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POWER SUPPLY INTERRUPTION COSTS: MODELS AND METHODS INCORPORATING TIME DEPENDENT PATTERNS

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Power supply interruption costs: Models and methods incorporating time dependent patterns

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Summary

The main results of this thesis are improved methods for the estimation of annual interruption costs for delivery points from electricity utilities to the end users. The improvements consist of a combined representation of time variation and uncertainties in the input variables. The time variation is only partly handled in methods reported in the literature. A particular result in this work is a unified representation of time variation in the input variables. This will enable the socio-economic costs of power supply interruptions to be determined more correctly. Consequently more credible estimates of this cost element can be provided as a basis for the optimization of the power system.

Recent customer surveys by the electric power industry on interruption costs provide better estimates of costs per interruption and more information on the characteristics of these costs, which can stimulate further studies of the annual costs. This is relevant as there is increased interest in the quality of power supply from both the customers and the regulation authorities. This calls for improved methods for assessment of interruption costs for delivery points at any system level.

Time variation and uncertainties

The annual costs from unexpected interruptions are determined by four variables: Failure rate, repair time, load and specific interruption cost. The customer surveys show that the cost per interruption has considerable variation depending on the time of occurrence. On average for the industrial and commercial sectors in Norway there is for instance a cost decrease of 40 % from working hours till midnight as well as from working days till weekends, while the monthly variation is up to 20 %. Examples from the failure statistics for distribution systems show that the probability of failures is three times higher in January than in May and about three times higher in working hours than at night. The repair times however, are about twice as high during night than during working hours and twice as high in winter as in summer. The failure statistics for the higher system levels in the transmission system show for instance that the probability of failures is three times higher in January than in summer and 60 % higher in working hours than at night, while the repair time is about 20 % higher in summer than winter and at night compared to day time.

These time dependent patterns indicate that there is a time dependent correlation between the input variables that might influence the annual costs. There are also stochastic variations in the input variables as well as other types of uncertainties, termed fuzziness in this thesis. A further result in this thesis is combining the representation of time variations and the additional uncertainties in the variables to show how these mechanisms may affect the annual interruption costs.

Models and methods
The time varying failure rate is represented by average cyclic variations based on observations of all types of failures, i.e., failures caused by climatical, technical and other causes (such as human). A description of these accumulated effects registered in the failure statistics is primarily suitable for the determination of expected variations in the long run. This makes use of the total number of failures observed for different types of components.

Both analytical methods and a Monte Carlo simulation method are developed using the same basic representation of time variation. The methods start with a list of outage events which may lead to interruptions at the delivery point. The annual interruption costs are thus found by summation of the contributions from the individual outage events. It is assumed that these outage events are predetermined by appropriate methods for load flow and contingency analyses. This approach allows the reliability assessment to be decoupled from time-consuming load flow analyses, and thereby simplifies the process of determining the annual interruption costs.

The uncertainties in input variables can be handled either by a Monte Carlo simulation giving probability distributions and confidence intervals for the reliability indices or by a fuzzy description giving the degree of fuzziness in the indices, represented by fuzzy memberships and intervals at a level of confidence. Both representations give valuable additional information.

Practical applications and case studies
The methods developed in this thesis are designed for practical applications in radial and meshed systems, based on available data from failure statistics, load registrations and customer surveys. The models and methods are illustrated for case studies ranging from simple examples to real cases from the transmission and distribution system.

One of the by-products from the methods is the calculation of traditional reliability indices, such as *annual interruption time*, and *power- and energy not supplied*. Depending on the method, all indices include the time variations and uncertainties in the input variables.

The methods are presented as algorithms and/or procedures which are available as prototypes. The algorithms can be implemented in existing tools for reliability assessment with the necessary extensions of models and data bases needed for different purposes.

Significance of time variation and correlation
The case studies show that the time dependent correlation may be significant for certain combinations of input variables. The correlation is particularly significant on a weekly and daily basis. Based on the failure statistics for distribution system, there is a strong positive correlation between the number of failures and cost per interruption, shown by a correlation factor about 0.8 both on weekly and daily basis for the industrial sector. This is counteracted

by a negative correlation between number of failures and repair time. The correlation factors are -0.6 and -0.7 on a weekly and daily basis respectively. In these examples the resulting correlation from the four input variables is not found significant for the annual interruption costs. Compared to the traditional method, the annual costs are reduced by 0 - 5 % while the energy not supplied is increased by about 10 %.

In radial systems each failure leads to an interruption, while in meshed systems interruptions occur only when the available capacity to supply the load is significantly decreased. This happens for a limited number of failures or outage events. If the probability of failures is high in periods when the load is high, the time varying failure rate may have a significant impact on annual reliability indices in transmission systems. This is illustrated for the transmission system case using two different relative time variations, the first with no characteristic pattern and the second with a strong positive correlation between number of failures and load. The correlation factors are about 0.5 and 0.8 on a weekly and daily basis respectively. In the last case energy not supplied is increased by 44 % and annual interruption costs by 24 % compared to the first case.

These conclusions are based on limited data and more studies are needed for radial and meshed systems to investigate the influence of the time variation on the annual indices. The methods developed in this work can be used to study this influence as well as the combined effect of time variations and uncertainties. A description which incorporates uncertainties in input variables will in most cases not influence the expectation values, but primarily give additional information. However, there are exceptions. The specific cost is a function of interruption duration. If this function is significantly nonlinear, the expected annual costs may be influenced. An example is included using two different probability distributions for the repair time: An exponential with variance 6.0 and a lognormal with variance 1.5. With a nonlinear cost function the exponential distribution gives about 6 % higher expected annual costs than the lognormal. The two distributions yield equal expected costs when the cost function is linear.

Application of specific interruption cost

Careful modelling of the data basis is necessary in the assessment of annual interruption costs. This work has shown that the application of a *normalized* interruption cost at a *reference* time may lead to significant underestimation of annual costs, i.e., when the normalization factor is *energy not supplied*. The absolute cost per interruption is divided by the energy not supplied providing the specific (normalized) cost. Thus, the time variation in the specific cost depends on the time variation in both the cost per interruption and the load. This yields for instance average specific costs on an annual basis which are 20 % and 57 % higher than the reference cost for an industrial load and a commercial load respectively. If a detailed time variation in the variables is not represented, the *annual average* cost function should be applied. Using the specific cost at reference time leads to an underestimation of the annual interruption costs of about 20-30 % in the transmission and distribution cases compared to not considering the time variation.

Table of contents

Appendices:

1. IEEE - Paper: RELRAD - An Analytical Approach for Distribution System Reliability Assessment
2. Estimation of covariance and correlation
3. Expectation method for radial systems
4. Paper presented at PSCC '96: Delivery point interruption costs: Probabilistic modelling, time correlations and calculation methods
5. Cost description: Customer costs and utility costs
6. Data and results for Chapter 7
7. Data and results for Chapter 8

List of symbols

APC	Available Power Capacity (kW or MW)
b	correction factor incl. time dependent correlation between EENS and the specific interruption cost
$\underline{c}$	vector describing the customers connected to a delivery point
c_P	customer specific interruption cost, for power not supplied (NOK/kW)
c_{Pref}, c_{Wref}	customer specific interruption costs at the reference time (NOK/kW and NOK/kWh)
$c_{Pref}(r_j)$	Customer Damage Function, for power not supplied (NOK/kW)
c_W	customer specific interruption cost, for energy not supplied (NOK/kWh)
c_{Wav}	customer specific interruption cost, average on an annual basis
c_{Wd}	customer specific interruption cost on weekdays (d)
c_{Wh}	customer specific interruption cost in hours (h)
$c_{W\,h,d,m}$	customer specific interruption cost in hours (h), weekdays (d) and months (m)
c_{Wm}	customer specific interruption cost in months (m)
$c_{Wref}(r_j)$	Customer Damage Function, for energy not supplied (NOK/kWh)
C	customer interruption cost (absolute) (NOK)
C_{ref}	customer interruption cost at the reference time (NOK)
C_d/C_{ref}	relative cost on weekdays (d)
C_h/C_{ref}	relative cost in hours (h)
C_m/C_{ref}	relative cost in months (m)
CDF	Customer Damage Function (describes the specific cost as a function of duration)
EENS	Expected Energy Not Supplied (kWh or MWh)
EIC	Expected Interruption Costs (NOK)
ENS	Energy Not Supplied
EPNS	Expected Power Not Supplied (kW or MW)
IC	Annual Interruption Costs (NOK)
IEAR	Interrupted Energy Assessment Rate = EIC/EENS (NOK/kWh)
k_{cd}	relative specific interruption cost on weekdays (d) = c_{Wd}/c_{Wref}
k_{ch}	relative specific interruption cost in hours (h) = c_{Wh}/c_{Wref}
k_{cm}	relative specific interruption cost in months (m) = c_{Wm}/c_{Wref}
$k_{\lambda P}$	correction factor, incl. time dep. correlation between λ and P, total annual factor
$k_{\lambda Pd}$	correction factor, incl. weekly time dependent correlation between λ and P
$k_{\lambda Ph}$	correction factor, incl. daily time dependent correlation between λ and P
$k_{\lambda Pm}$	correction factor, incl. monthly time dependent correlation between λ and P
$k_{\lambda Pc}$	correction factor, incl. time dep. correlation between λ, P and c, total annual factor
$k_{\lambda Pcd}$	correction factor, incl. weekly time dependent correlation between λ, P and c
$k_{\lambda Pch}$	correction factor, incl. daily time dependent correlation between λ, P and c
$k_{\lambda Pcm}$	correction factor, incl. monthly time dependent correlation between λ, P and c
$k_{\lambda Pr}$	correction factor, incl. time dep. correlation between λ, P and r, total annual factor

$k_{\lambda Prd}$	correction factor, incl. weekly time dependent correlation between λ, P and r
$k_{\lambda Prh}$	correction factor, incl. daily time dependent correlation between λ, P and r
$k_{\lambda Prm}$	correction factor, incl. monthly time dependent correlation between λ, P and r
$k_{\lambda Prc}$	correction factor, incl. time dep. correlation between λ, P, r and c, total annual factor
$k_{\lambda Prcd}$	correction factor, incl. weekly time dependent correlation between λ, P, r and c
$k_{\lambda Prch}$	correction factor, incl. daily time dependent correlation between λ, P, r and c
$k_{\lambda Prcm}$	correction factor, incl. monthly time dependent correlation between λ, P, r and c
k_{pd}	relative load on weekdays (d) = P_d/P_{av}
k_{ph}	relative load in hours (h) = P_h/P_{max}
k_{phd}	relative load in hours (h) on weekdays (d) = $P_{h\,(wd)}/P_{max}$ or $P_{h\,(we)}/P_{max}$
k_{pm}	relative load in months (m) = P_m/P_{av}
k_{rd}	relative repair time on weekdays (d) = r_d/r_{av}
k_{rh}	relative repair time in hours (h) = r_h/r_{av}
k_{rm}	relative repair time in months (m) = r_m/r_{av}
λ	symbol both for failure rate and interruptions
λ_{av}	average annual no. of failures or interruptions
λ_{cut}	equivalent annual no. of failures for a minimum cut
λ_d	portion of annual number of failures occurring on weekdays (d)
λ_h	portion of annual number of failures occurring in hours (h)
$\lambda_{h,d,m}$	expected portion of annual no. of failures in hours (h), weekdays (d) and months (m)
λ_m	portion of annual number of failures occurring in months (m)
LG	Local Generation (kW or MW)
n	number of years calculated
N_i	number of interruptions in year no. i
$\underline{p}$	vector describing the reliability level
P	load (kW or MW)
P_{av}	annual expected load (=W/8760)
P_d	expected load on weekdays (d), independent of the month
P_h	expected load in hours (h), independent of the weekday and the month
$P_{h,d,m}$	expected load in hours (h), weekdays (d) and months (m)
$P_{h\,(wd)}$	expected load in hours (h) on working days
$P_{h\,(we)}$	expected load in hours (h) at weekends
P_m	expected load in months (m)
P_{max}	annual maximum load (=W/T_b)
P_{ref}	expected load at reference time in customer surveys on interruption costs
$P(t_j)$	expected load in the time period $r(t_j)$
PNS	Power Not Supplied (kW or MW)
$q_{\lambda d}$	relative portion of annual number of failures occurring on weekdays (d), probability of failures on weekdays (d)
$q_{\lambda h}$	relative portion of annual number of failures occurring in hours (h), probability of failures in hours (h)

$q_{\lambda m}$	relative portion of annual number of failures occurring in months (m), probability of failures in months (m)
r	component repair time, time for restoration of supply, or duration of interruption (hours per failure or hours per interruption)
r_{av}	annual average component repair time, time for restoration of supply or duration of interruption (hours per failure or hours per interruption)
r_{cut}	equivalent repair time of failures caused by a minimum cut (hours per failure)
r_d	expected repair time on weekdays (d)
r_h	expected repair time for hours (h)
$r_{h,d,m}$	expected repair time in hours (h), weekdays (d) and months (m)
r_m	expected repair time in months (m)
$r(t_j)$	expected duration when the interruption occurs at t_j
SAC	System Available Capacity (kW or MW)
SCDF	Sector Customer Damage Function (NOK/kW)
T_b	Utilization time ($=W/P_{max}$) (hours)
t_j	time of occurrence of interruption no. j
U	Annual interruption time (hours/year)
W	Annual energy consumption (kWh or Mwh)
w	weight for composing aggregate CDFs, e.g. a customer group's proportion of W in the delivery point
$\underline{x}$	vector describing the loads at the delivery point
$\underline{y}$	vector describing the local generation or reserve facilities

1 Introduction

This chapter gives the background and motivation for the thesis. A brief introduction to different reliability methods is included, and uncertainties in reliability analyses and annual interruption costs are discussed. The main objectives and contributions of the thesis are described. Finally an outline of the thesis is included.

1.1 Background

The deregulation of the electricity supply sector that is an ongoing process in many countries, has resulted in a stronger market orientation and competition among the power companies. The customer has been put into focus, and the quality of supply is being given increased attention by customers, power companies and the central authorities.

There is pressure on the companies to be more cost effective in various respects, while the economic situation is less predictable. Future price regulations may prevent utility costs being automatically transferred to the customers. This could lead to a more cautious use of corporate funds, meaning postponed investments, a reduction in maintenance, fewer employees and so on, but also increased use of cost-benefit analysis. There will be trade offs between the customers' demand for quality and the interests of utilities in economic terms.

The current trend of operating power systems closer to their limits is expected to continue. Combined with the increased complexity of the systems, the reliability may decline. At the same time society's dependence on continuous supply and the vulnerability to power interruptions is increasing.

This situation obviously calls for better documentation of the quality of supply and better knowledge of customers' perceptions and requirements. Appropriate tools are needed to meet the challenges that arise in the different phases of planning, operation and maintenance of the system.

Traditionally deterministic criteria have been used to maintain the quality of supply or the reliability in system planning and operation. There are certain critical contingencies that the system is to withstand, the (N-1)-criterion etc., and during recent decades there has been an increased interest in probabilistic methods and criteria.

Several investigations have been conducted on customers' expectations and experience with the quality of supply and their perceptions of interruption costs. Usually customer surveys are used to collect the necessary information. In system planning, interruption costs have also been explicitly used to a certain extent [1].

In some countries there are explicitly stated requirements in the legislation concerning the quality of supply. An example is the Norwegian Energy Act, which states that the concessionaire (electricity utility) should inform the customers about the expected quality, and that quality aspects should be taken into account in planning, operation and maintenance of the power system. Furthermore the monopoly part of the system, the transmission and distribution, should be optimized from a socio-economic point of view. According to the Norwegian Water Resources and Energy Administration (NVE), the following cost elements should be considered:

- Investment costs
- Costs of electrical losses
- Operation and maintenance costs
- Interruption costs.

Another intention of this Act is that the price of the electricity product should be in accordance with the quality offered. Thus the quality of supply will become an important operational concept.

1.2 Reliability analysis

Reliability methods for transmission and distribution reliability analysis have been available for about 30 years [1]. The methods have been under considerable development since then. Here, there are two main approaches: Simulation methods (Monte Carlo) and analytical methods. Both methods have strengths and weaknesses.

Using Monte Carlo simulation the real system behaviour can in general be simulated and different operational strategies/policies can be included. Simulation is however a very time-consuming procedure compared to the analytical approaches which are computationally effective. Analytical approaches suffer from problems by representing complex systems analytically according to system behaviour, breaker- and operator-actions etc., and certain assumptions have to be made. Improvements have been made in both approaches and there are also methods available combining the two, the so-called hybrid methods.

Although reliability methods have been available for a long time, the methods are not extensively used by the power companies. Planning is still based on deterministic reliability criteria, while the probabilistic approaches may be used as a supplement to make relative comparisons between different operation schemes, different system alternatives and so on. The hesitation or reluctance to adopt such methods is often based on uncertainties associated with the calculated results, caused by limitations and inaccuracies in methods and reliability data. Up to now there have been few incentives to improve the data basis of different parameters involved due to the inadequacy of models and methods, and vice versa.

Organizations such as CIGRE, CIRED and UNIPEDE have been concerned about these topics for several years [2, 3], and there has been a lot of activity within this field in many countries, shown by a comprehensive body of published papers [1, 4]. There is increasing interest in the documentation of component failures and power supply interruptions and in the handling of the quality of supply in general.

The quantification of reliability and total interruption costs will be of primary importance in power system planning, both on the short- and long- term, in the evaluation of:

- different system alternatives
- different operational strategies/policies
- specific reliability measures
- different planning criteria
- expected quality of supply to customers
etc.

1.3 Uncertainties in reliability analyses and interruption costs

Uncertainties associated with the application of results from reliability and interruption cost calculations are attributed to aspects such as stochastic variations, lack of data or knowledge of different parameters, the use of past performance data to predict future reliability performance, and varying time horizons in the planning of power systems.

System planning typically covers a time horizon of 10-20 years, while the economic lifetime of the various system components can be much longer. With such long time constants, the decision making should be based on robust results. Compared to an optimization principle which takes into account the three cost elements of investments, maintenance and electrical losses, the inclusion of interruption costs *may* result in quite different investments. This is shown by several case studies, such as [5, 6].

There is no precise definition of the socio-economic interruption costs or the total costs imposed on society by curtailment of electricity supply. Such costs comprise both direct and indirect effects, which are difficult to observe and evaluate. According to NVE, for planning purposes the socio-economic interruption costs can be approximated by the sum of customers' total aggregate interruption costs and the electric utilities' direct costs of failures and interruptions. Hence these cost elements are assumed to be a measure of *worth of reliability* to society.

Reliability analyses typically comprise the determination and evaluation of consequences of component failures regarding electrical conditions within the system and the interruption of supply to delivery points and customers. The consequences are usually given by the expected frequency and duration of different problems, and there are several reliability indices in use. With the explicit application of interruption costs in system planning, total interruption costs are typically calculated using average specific costs for different customer groups, combined with expected power and energy not supplied. This process involves the combination of a reliability model, a load model and a cost model as illustrated in Fig.1.1.

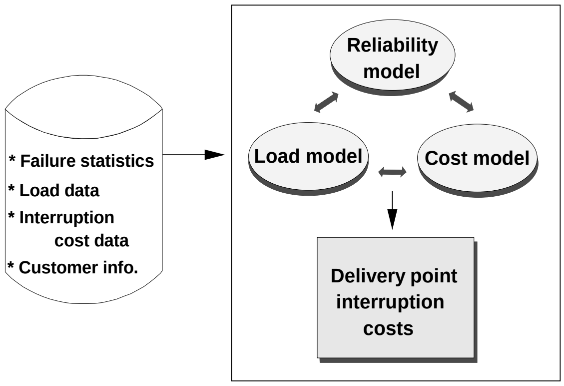


Fig.1.1 Assessment of annual interruption costs for general delivery points.

The main data sources needed to calculate annual interruption costs for delivery points/customers are:

- component failure- and repair rates
- load levels and load profiles
- customer interruption costs.

Reliability analyses are based on statistical information on component failures and repair rates and load variations, which are all stochastic in nature. The statistical material should ideally represent a large number of both years and objects to give reliable estimates of probability distributions and expectation values. In various countries power companies have been collecting information on component failures for many years. Despite the increasing amount of data collected, the material is and will be associated with some kind of uncertainty, such as:

- different interpretations of collecting schemes
- imperfect or insufficient data
- missing information, lack of data
- limited number of observations of some particular components.

The collected information covers existing and replaced components. Further uncertainty is introduced by the application of historical data for prediction of future interruption costs.

The knowledge of typical load profiles and utilization times for different load categories is quite comprehensive, and there are tools available to determine the peak demand for an area based on this kind of knowledge in combination with climatic information and load measurements. The prediction of the future demand is however uncertain due to changes in demographic, political and other social parameters etc., while the load level itself is vital for the probability of interruptions.

Customer interruption cost estimates are available from customer surveys conducted in various countries. The surveys show that these costs depend on the duration of interruptions, the load and the customer category, and the time of occurrence. The interruption costs vary considerably within and among the customer categories.

The cost estimates reflect the inconvenience and economic losses arising from interruptions of power supply, and to some extent they also reflect the customers' willingness to pay for a certain quality level. The cost estimates are based on both subjective and objective judgements, deduced from the direct economic consequences of interruptions. So far results from customer surveys are mostly given on a broad national basis. Only a few companies have made local investigations.

Of the above-mentioned variables, the customer interruption cost is probably the most uncertain or fuzzy variable associated with different kinds of uncertainty, such as subjectivity, imprecision or lack of knowledge.

1.4 Value Based Reliability Planning

Reliability cost/worth considerations and the use of cost-benefit analyses in the planning process is often called Value Based Reliability Planning (VBRP), see for example [31, 69, 70]. The objective of VBRP is to balance the utility's investment costs against the interruption costs experienced by its customers.

A qualitative illustration of the optimization problem and the reliability/cost relation is given in Fig. 1.2. The figure gives the total socio-economic costs as the sum of investment costs (T/D), costs of electrical losses (EL), operation and maintenance costs (OM) and interruption costs (IC). The cost curves are arbitrarily chosen.

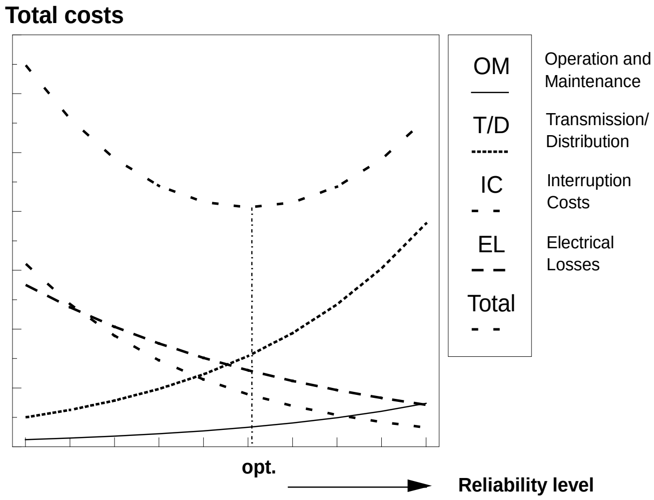


Fig. 1.2 Reliability/cost relation.

The optimum reliability level is reached where the total costs are at the minimum (marked in the figure). A higher reliability level than the optimum, to the right in Fig. 1.2, would give too high incremental T/D and/or OM compared to the reduction in IC (and EL). This means that over-investment has taken place, and the reliability level should be decreased. Similarly a lower reliability level, to the left in Fig. 1.2, would represent under-investment, which means that it is economically feasible in socio-economic terms to increase the quality level.

Theoretically it is possible to increase the reliability to nearly 100%, yielding unacceptable investment costs. Introducing more equipment, however, results in more sources of failure, which in fact can lead to increased interruption costs (or a declined reliability). Similarly, increased maintenance beyond a certain reliability level, would result in more disconnections and thus increased interruption costs. Costs of electrical losses will usually decrease by increasing the reliability level due to changes in network structure.

Although the electricity utilities have continually attempted to provide a reliability level in accordance with society's expectations, large variations in supply reliability are observed between different areas. Customers supplied by underground cable networks typically experience very few interruptions, while the reliability can be very poor in rural areas supplied by overhead lines. Cost-benefit analyses, e.g. in Norway, show that simplifications (savings in investment costs) can be made in the cable systems without any significant deterioration in reliability level, or even with increased level due to the reduction in the number of components. In overhead systems there can be a relatively high potential for savings in customer interruption costs, often as a result of relatively small investments [7, 8].

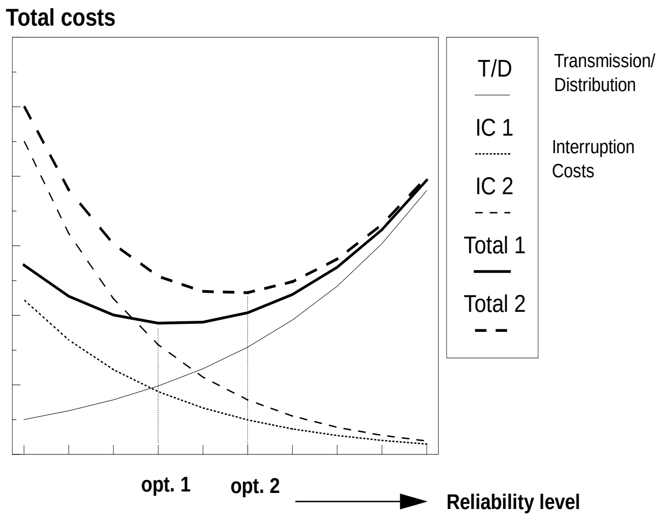


Fig. 1.3 Different optimum reliability level.

Traditional policy among the utilities has often been to try to level out quality differences in their supply area and also has the additional target of improving the reliability. The socio-economic optimization principle, however, implicitly involves a differentiation in the reliability level between different areas and customer groups. For a particular system plan and a supply area with a certain customer mix, the minimum cost approach results in a reliability level which can be quite different from another supply area. A customer mix with lower interruption costs will principally be provided with a lower reliability level. This is illustrated in Fig. 1.3. Lower specific interruption costs give a flatter interruption cost-curve.

The optimization principle implies discrimination of rural areas compared to central parts where a high level of reliability is reached with moderate cost. This could lead to very poor or unacceptable reliability in distant, low populated areas. A significant improvement in the quality level in rural areas would subsequently result in increased rates (tariffs) which can conflict with the correspondence between the quality and the price offered. Is it acceptable that rural customers pay equal or higher tariff than centrally located customers if they have lower supply reliability?

The customer mix in a supply area can be a significant parameter in the assessment of optimum reliability level. For instance, a few customers with a very high specific interruption cost may have a relatively high impact on the total interruption costs, yielding a higher optimum reliability level. Still this level may prove to be unacceptable for these particular customers, while the majority of the customers are provided too high reliability. It may be a question of establishing trade offs between supply side and demand side measures to satisfy both the customers' demand for reliable supply and the utilities' economic interests. A definition of minimum reliability levels may prove to be useful, this could be based on acceptance from different customer groups, in combination with the minimum cost approach.

1.5 Scope of work and contributions

Traditional methods combine expected power- or energy not supplied with a specific interruption cost to calculate annual interruption costs. Recent customer surveys have shown that the costs per interruption may have considerable variation depending on the time of occurrence, especially with the day of the week and time of the day. It is well known that the customer loads are characterized by typical daily, weekly and monthly cycles. Reports on failure rates and repair times reveal that these variables have similar time dependent patterns. It can be observed from the time profiles that peak values of the variables tend to occur at the same time.

Thus, the following questions become important: Is the time dependent correlation between the variables significant for the annual interruption costs? How can this time variation be represented in calculation models for annual interruption costs?

There are additional uncertainties in the input variables affecting the uncertainties in the annual interruption costs. How can a description of the uncertainties be combined with the representation of the time variation in the calculation models?

Can we come up with practical methods that can be recommended for the electricity utility industry to meet the new challenges about value based planning and cost-benefit analysis? How can the new aspects concerning interruption costs be combined with the comprehensive source of knowledge and experience on traditional reliability analysis?

The main objective of this research work has been to give an answer to these questions and the related issues. More specifically the approach adopted in order to answer the questions has been to develop models and methods for estimation of annual interruption costs for delivery points, with emphasis on the handling of time dependent patterns and uncertainties in the variables determining the annual costs. The development is based on an appropriate integration of the three models shown in Fig. 1.1.

The main contributions from this work can be summarized as follows:

- Analytical method for calculation of annual expected interruption costs for delivery points in radial systems, based on a radial reliability model. Time variations in variables are handled in the method.

- Analytical method for calculation of annual expected interruption costs for delivery points in meshed systems, based on a list of outage events (minimum cuts). It is assumed that these events are found in advance from load flow and contingency analyses. Time variations in variables are handled in the method.

- Monte Carlo simulation model which handles both time variations and stochastic variations in the input variables, based on the same list of outage events. This is a general procedure for radial and meshed systems. The method provides both expectation values and probability distributions for interruption costs from delivery points.

- A procedure for handling of uncertainties in input variables by a fuzzy description, giving annual interruption costs as a fuzzy membership function.

The methods are developed for practical applications in radial and meshed systems, based on available data from failure statistics, load registrations and customer surveys. As by-products from the methods traditional reliability indices are calculated, such as annual interruption time, power- and energy not supplied. Depending on the method, all indices include the time variations and uncertainties in the input variables.

The methods are presented as algorithms and/or procedures which are available as prototypes.

1.6 Outline of the thesis

The thesis is organized as follows:

Chapter 2 gives an overview of customer surveys to provide estimates for customers' interruption costs. The discussion concerning uncertainties in the application of cost estimates is summarized. The main interruption related and customer related factors affecting the cost estimates are outlined. Existing methods for assessment of annual interruption costs are discussed both in relation to expectation values and the handling of uncertainties in input variables.

In Chapter 3 a description of the general delivery point is given, based on an aggregate and detailed level. The assessment of interruptions to the delivery point, i.e., frequency and duration, is outlined for the general case in meshed and radial systems. Determination of power- and energy not supplied is described. Finally a description is given of the reliability model which is chosen for the development of methods.

Chapter 4 gives a presentation of the available historical data on failures, repair times, loads and interruption costs. The data are taken from Norwegian data bases as examples of typical data for these purposes. Focus is placed on time variations and stochastic variations.

In Chapter 5 the problem of assessing annual interruption costs and the handling of time variations and uncertainties is described in general. The reliability, load and cost models are presented with the extensions needed to handle the time variation. A general formulation of the annual interruption costs for a general delivery point is given.

Chapter 6 gives the description of the models and methods developed in this work. Analytical methods for radial and meshed systems are presented which take time variation in input variables into account. A Monte Carlo simulation method is developed which handles both time variation and stochastic variation. The method can be equally applied to radial and meshed systems. A procedure for the handling of uncertainties by a fuzzification of the input variables is described in relation to the analytical method for radial systems.

In Chapter 7 the calculation methods are illustrated for some simple examples using the example data from Chapter 4. The influence of time variation and time dependent correlation is demonstrated and a comparison is made with the traditional analytical method. Various types of probability distributions are used to show the influence of stochastic variation in the different variables. It is shown how a fuzzy description of the variables can be handled to determine the uncertainty in annual interruption costs.

In Chapter 8 the methods are applied to two more realistic examples, a transmission system and a distribution system. Typical local and global decision problems are first described to provide the context for the application of results from these methods. For both cases the methods are used to calculate reliability indices, and in the distribution system case a cost-benefit analysis (local decision problem) is included to illustrate possible applications of the results.

Chapter 9 gives a discussion of the different methods developed in relation to the main issues studied in this research work. The main conclusions from the work are summarized and some recommendations for further work are given.

A list of symbols is included before Chapter 1.

Appendix 1 includes a paper describing the radial reliability model used as a basis for the developed expectation method for radial systems. Some modelling details for this method are given in Appendices 2 and 3. A paper describing major parts of the work is included in Appendix 4. Appendix 5 gives a more detailed description of the customers’ and utilities’ variable costs according to interruptions. Some data and results for the case studies in Chapters 7 and 8 are given in Appendices 6 and 7.

2 Assessment and application of customer interruption costs - an overview

Results from a literature survey on customer interruption costs are given in this chapter. Typical results from customer surveys on interruption costs are presented. Reference is made to the discussion concerning uncertainties in the application of the cost estimates provided from the surveys. The main factors affecting the cost estimates are outlined. Existing methods for estimation of annual interruption costs are discussed, both in relation to expectation values and the handling of uncertainties.

2.1 Customer specific interruption costs

The socio-economic costs of interruptions, or the worth of reliability to society, are often approximated by the costs incurred by customers due to interruptions in the electricity supply [18]. According to the Norwegian authorities (NVE) the socio-economic interruption costs can be approximated by the sum of the total aggregate customer interruption costs and the electricity utilities' direct costs of failures and interruptions [19, 20], see Chapter 1. This thesis now focuses on the assessment of customers' interruption costs.

Different approaches and methods have been used to provide estimates of customers' interruption costs [18]. During the past decade the customer survey method has become accepted and seems to be the most appropriate approach for this purpose discussed in [21, 22, 30] amongst others. This section attempts to give a broad review of this method and does not intend to go deeper into the discussion about this or other methods to estimate customers' interruption costs. In following chapters, cost estimates are used, based on the Norwegian survey conducted in 1989-1991 [20].

2.1.1 Customer surveys

Several customer surveys are reported in the literature in the recent years [23 - 36]. The surveys are usually conducted as mailed questionnaires, sometimes followed by telephone interviews. A thorough presentation of the development of the survey approach as well as a discussion on strengths and weaknesses of this method is given in [18], for example.

In the survey method customers are asked to estimate their costs and losses for different interruption scenarios. Hypothetical questions seem to be preferred to give predictions and expectations for future interruptions of varying duration, and at different times of the day and year. These predictions will be based on the perceptions of past interruptions. For some types of customers (e.g., industrial and commercial) the direct costs incurred are relatively easy to determine, while for other categories such as residential, cost estimates will be more based on users' opinions.

Customers are typically classified or grouped into major customer categories such as industrial, commercial, agricultural and residential. A Standard Industrial Classification (SIC) system is commonly used for further classification within the major categories. The SIC system is country-specific [33].

Questionnaires are designed for each of the major categories, adjusted to the type of customers. In general the questionnaires might contain questions on aspects such as customer demographics, principal use of electricity, perceptions on past interruptions, available standby, and energy and demand information, in addition to the cost evaluation part.

Different cost evaluation approaches might be used in the survey. There are three methods to be mentioned here:

- Direct costs evaluation
- Indirect worth evaluation
- Contingent worth evaluation.

The direct costs evaluation is applicable to the industrial and commercial sectors, whose direct costs are easily identified for given interruption conditions. Guidance can be offered as to which cost elements should be included. Typical cost elements are lost production and lost sales, costs of wages for overtime, damaged equipment and start-up costs.

Indirect worth evaluation may consist of different aspects. One approach that is often used in the residential sector, is the evaluation of preparatory actions such as insurance policies and standby generators. The cost estimates derived from this indirect worth evaluation are considered to be the customer's valuation of avoiding different interruption consequences.

In the contingent worth evaluation, customers are asked what they are willing to pay to avoid the interruption, or conversely what they would be willing to accept in compensation for having an interruption. The willingness to pay (WTP) is considered to represent the valuation of marginal increments in reliability. Likewise the willingness to accept (WTA) would represent the valuation of marginal decrements in reliability. Theoretically WTP and WTA estimates should be nearly equal. However, results from this evaluation approach yield WTP-estimates that are significantly less than the WTA-estimates.

The questionnaires typically contain hypothetical questions on cost valuation for *different interruption scenarios*, such as:

- momentary interruptions
- interruptions of 1 hour, 4 hours, 8 hours and 24 hours
- cost reduction for planned interruptions
- cost variation for different months, days of the week and hours of the day.

The interruption scenarios are usually given for a base case, or a *reference time*, such as a Thursday in January at 10:00 a.m.

Results from the customer surveys are usually presented as *normalized* cost estimates per sector for the different scenarios. Normalized cost estimates are costs per interruption referred to annual energy demand, peak load or energy not supplied. The normalization is conducted in order to provide comparable cost estimates for the different customers and customer groups. Another reason is that power system planning methods are mostly based on power demand and energy consumption.

2.1.2 Results from Norwegian and Nordic surveys

This section gives some results from the Norwegian survey [20] conducted in 1989 - 1991 and the Nordic survey [29] conducted in 1992 - 1993. These are examples of cost estimates provided by customer surveys on interruption costs.

The main results from the Norwegian survey are presented in three reports in Norwegian [34-36] and the background for the survey is given in [22]. In this survey the direct, indirect and contingent evaluation approaches are used. The cost estimates are normalized by *energy not supplied* for the different durations, in NOK/kWh. The main results are given in Table 2.1, costs updated to account for inflation up to 1995. The reference time (base case) is January, see below.

Table 2.1 Specific interruption costs in NOK per kWh *energy not supplied* for unexpected interruptions. Cost level 1995.

Customer category	Interruption duration		
	1 hour	4 hours	8 hours
Industrial	55.3	43.7	43.3
Commercial	38.7	40.4	46.4
Agricultural	1.2	4.0	8.5
Residential	2.4	9.1	10.8

For the industrial and commercial sectors cost estimates for a 1 minute interruption are found to be:

Industrial:	10.8 NOK/kW
Commercial:	7.4 NOK/kW

These are referred to the load at reference time (which is practically equal to the annual peak load).

The above cost estimates are based on the following:

Industrial and Commercial	*Direct costs* referred to unexpected interruptions on a *Thursday* in *January* at *10:00 a.m.*
Agricultural	*Direct costs* referred to interruptions on a *Thursday* in *January* at *06:00 a.m.*
Residential	*Willingness to pay* to avoid interruptions occurring one *afternoon* in *January*.

The cost estimates in Table 2.1 are expectations (or means) for each sector. There is considerable variation in costs among SIC groups in each sector and within each SIC-group. Variations within groups are usually much less than between groups [18, 34-36].

A cost function can be established based on the discrete values given for the surveyed interruption durations, like those in Table 2.1. The cost function gives the cost in NOK/kW as a function of interruption duration. Such functions are usually referred to as Customer Damage Functions (CDF). CDFs for the major customer categories or sectors are often denoted Sector Customer Damage Functions (SCDF). Cost estimates for intermediate interruptions are found by linear interpolation [32].

The Sector Customer Damage Functions for the 4 major categories in Table 2.1 are shown in Fig. 2.1.

The Nordic survey was conducted in 1992 - 1993 in Denmark, Finland and Iceland, and results were compared with the Norwegian survey and a Swedish survey conducted in 1992-1993 [66]. The results are presented in [21, 29]. The reference time or base case in the Nordic survey is winter weekdays. The SCDFs for unexpected interruptions in the five Nordic countries are given in Figs. 2.2 and 2.3 in DKK/kW, cost level 1993. For the residential sector, the SCDFs are not comparable, due to the different methods applied to evaluate the costs. However, the willingness to pay for a 1 hour interruption is shown in Fig. 2.3.

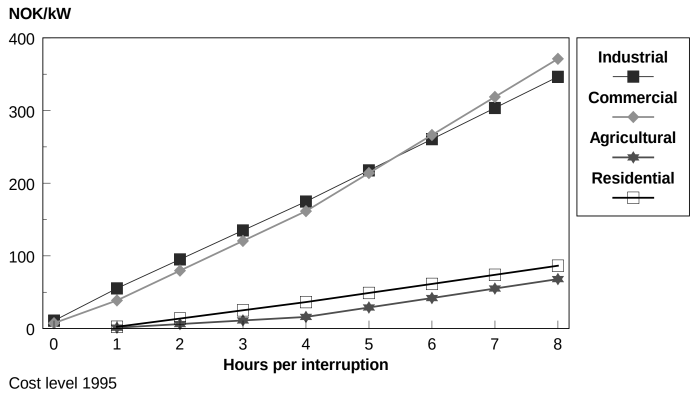


Fig. 2.1 Sector Customer Damage Functions from the Norwegian survey. Cost level 1995.

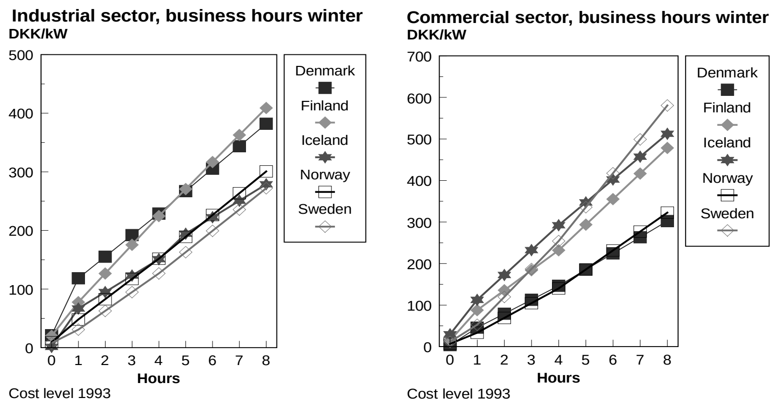


Fig. 2.2 Comparison of SCDFs for industrial and commercial customers in the Nordic countries. Cost level 1993.

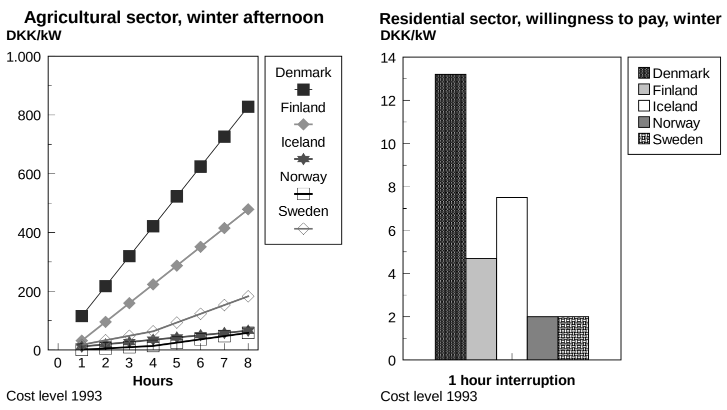


Fig. 2.3 Comparison of SCDFs for agricultural and residential customers in the Nordic countries. Cost level 1993.

Figs. 2.2 and 2.3 show that the results differ among the Nordic countries. The differences are partly due to different worst cases for interruptions and differences among the customer groups. For instance, the agricultural sector in Denmark is more industrialized than in the other countries.

2.1.3 Uncertainties in application of cost estimates

Uncertainties associated with estimates of customer interruption costs and the application in power system planning is discussed by several authors, referred to in [18, 32, 37] amongst others.

The specific interruption costs which are provided as results from customer surveys are based on both objective and subjective evaluations. Direct costs of hypothetical interruptions will be associated with uncertainties due to quality expectations and predictions about the future. The willingness to pay is similarly based on users' opinion of changes in the reliability level.

Cost valuation at the time of conducting the survey will be based on earlier experience with interruptions and on predictions based on the existing reliability level. Thus the cost estimates will be a function of the reliability level itself and as such they will be relative in time. Interruption costs will change over time due to the changes in the use of and dependence on electricity. Comparisons between studies conducted at different times have shown that the interruption costs have increased more than inflation [66].

Cost estimates like those presented in the previous section are mean values for broad customer categories. The dispersions in costs are considerable among the SIC groups in the different major sectors, but also within each SIC group. The cost estimates are usually given for a *reference time* (or base case), while the costs may vary considerably with time of the year, day of the week and time of the day, as shown in the next section.

Different customer surveys may give significantly different results (cost estimates) even if they are conducted in the same time period. The differences may be due to the use of different normalization factors and different reference times. For commercial customers for instance, in an English study [25] the reference time is a Wednesday in October at 04:00 p.m., in a Canadian study [26] a Friday at 10:00 a.m. at the end of January, while in the Norwegian survey the reference time is a Thursday in January at 10:00 a.m. Other factors are different types of customers, variations in reliability level and climatic as well as social and demographic differences. The content and design of the questionnaire and the types of questions may vary, and the questions may be interpreted differently by customers.

It is also being discussed which interruption scenarios the cost estimates are viable for. Many customers have little if no experience with very long or very frequent interruptions, and the specific interruption costs are hardly valid for interruptions with a duration more than 24 hours etc. Several authors assume that the interruption scenarios used in customer surveys are within the normal variations. As such the cost estimates should be appropriate for planning purposes, with the limitations mentioned above.

The vast majority of interruptions are of a local character, limited to a portion of the distribution system and affect a limited number of customers. Failures in the transmission system however, can lead to area-wide blackouts. Such events may affect a very large number of customers. The impact may be comparable to rare events like extremely bad weather (heavy storms) leading to lots of failures and long interruptions in the power supply. Application of cost estimates based on customer surveys when considering catastrophic events is a matter of discussion [37]. Under such conditions an aggregation of the customers' cost estimates may result in considerably underestimating the total costs of the area-wide blackout. In such cases the cost estimates may provide a lower bound for cost-benefit analyses.

2.2 Main factors affecting cost estimates

The customer surveys have focussed on varying characteristics of interruptions. Results show that there are several factors affecting the customers' expectations and perceptions of the quality of supply. These factors can be divided in two main categories: *interruption* related and *customer* related factors. This section deals with the most important factors considered and discussed in the literature.

2.2.1 Interruption related factors

The most important interruption related factors are:

- frequency of interruptions
- duration of interruptions
- time of occurrence
- time for advance warning in case of planned interruptions.

In some surveys the influence of the *frequency* of interruptions on the cost per interruption is studied. An example is given in [39] for residential customers where the willingness to pay for a 4 hour weekly interruption is higher than for a 4 hour monthly interruption. However, 1 hour daily interruption does not show any larger costs per interruption than the weekly interruption. A saturation effect seems to appear for very frequent interruptions. Studies referred to in [41] indicate that the cost per interruption decreases with increasing frequency. In the Nordic survey [29] it was shown that three repeated short interruptions within 15 minutes due to automatic breaker reclosure for instance, yield higher costs than a 1 minute interruption.

There seems to be some ambiguity in the results reported in the literature according to the relation between frequency and cost per interruption. Cost estimates from the customer surveys are usually not given as a function of frequency, see next section. According to [47], a cost description which is independent of the frequency of interruptions is a reasonable assumption within the range of frequencies normally considered.

Results reported from the various surveys show that the *duration* of interruptions is a dominant factor for the consequences to customers. Some customers are vulnerable to very short interruptions, in the range of seconds to some minutes, while others have responded zero cost for short interruptions and increasing costs for increasing duration. The variation in cost estimates with varying duration are different for the various customer sectors. In general the cost functions do not linearly increase with greater duration. This is seen from the specific costs in Table 2.1 and the cost functions in Figs. 2.1, 2.2 and 2.3. A common approach is to assume a piecewise linear function between the studied durations.

Some of the customer surveys conducted have also studied the cost variation with different *times of occurrence*, with month of the year, day of the week and time of the day. There is a significant cost variation on a weekly and daily basis reported from the Norwegian survey. Examples are given in Fig. 2.4 for the commercial sector, for cost per interruption (NOK). Similar results are reported in [26] for Canadian customers.

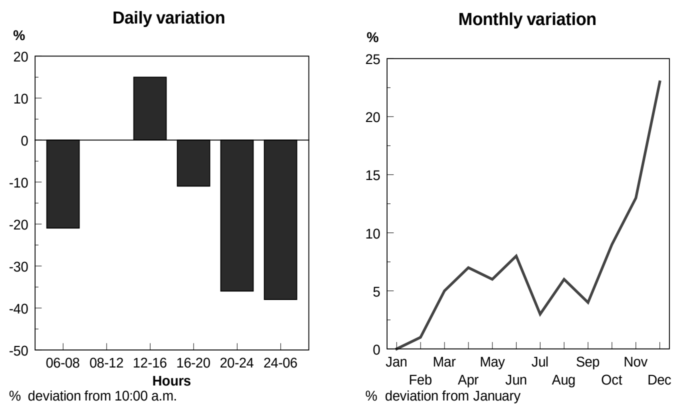


Fig. 2.4 Variation in cost per interruption referred to the reference interruption (base case), commercial sector, Norwegian survey.

The relative cost variation in Fig. 2.4 is a weighted average for the commercial sector. The weighting used is the cost for 4 hour interruption at reference time. The figure shows that the cost reduction is nearly 40 % at midnight compared to the reference time at 10:00 a.m., while there is a cost increase of up to 23 % in December compared to January. On average January is in fact the month with the lowest cost for this sector. The time variation in interruption cost varies among the SIC classes, especially in the industrial sector.

If customers receive advance warning in the case of planned interruptions, the costs may be considerably decreased. The time for advance warning considered necessary varies from 8 hours to 25 hours for industrial customers in the Nordic survey. This survey shows that the largest cost reductions are achieved for the short interruptions of less than 1 hour. The cost reductions differ among the SIC classes, for industrial customers the cost reduction is typically 50 - 70 %. In the Norwegian survey an average of about 30 % reduction was found for the industrial and commercial sectors with 24 hour advance warning. The corresponding percentage reduction from the Canadian survey from 1991 [27] is about 50 % for both the industrial and commercial sectors.

2.2.2 Customer related factors

The most important customer related factors considered are:

- Power demand/energy consumption
- Type of customer/customer category
- Availability of reserve supply (standby)
- Geographical/demographic factors.

In the Canadian study reported in [26] it was observed that the cost per interruption was influenced by the business size, characterized by area, annual sales and number of employees. After normalization of the cost by energy consumption or peak demand, other customer specific factors were found to be of no importance for a particular customer group. The normalization approach makes the interruption costs comparable. Such comparisons show that the cost in general is a function of the power and *consumption*, see for instance [42].

The customer surveys reveal considerable differences in cost estimates between the major *customer categories*, but also among the SIC classes. An example is shown in Fig. 2.5 for the industrial SIC classes used in the Norwegian survey, for 1 hour interruption at reference time.

The cost varies from 6 NOK/kWh for oil production & mining to 107 NOK/kWh for graphic industry, while the average for the industrial sector is about 55 NOK/kWh for a 1 hour interruption.

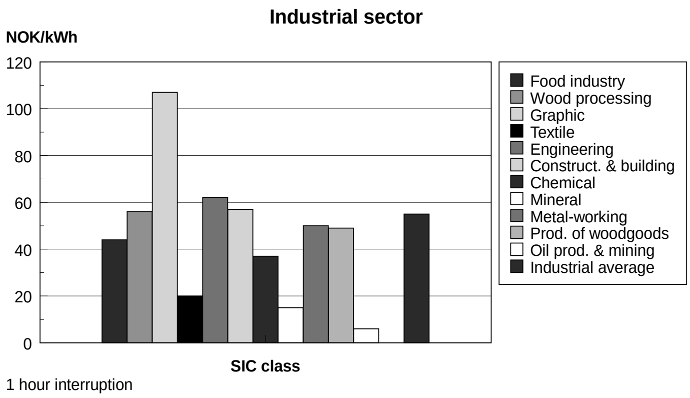


Fig. 2.5 Specific interruption costs for industrial subsectors, Norwegian survey, cost level 1995.

The direct costs associated with an interruption are obviously a function of the *types of electrical processes (loads)* within the business and the use of electricity. In most of the surveys conducted the respondents (industrial and commercial) are asked to estimate the direct costs of various *functions* influenced by the interruption, but not for different loads. The advantage of dividing the total cost per interruption in costs per process is emphasized in [25]. This makes it possible to separately consider computer backup, reserve supply investments and other aspects such as the valuation of interruptible and critical loads.

The relation between interruption costs and the availability of *reserve supply* is investigated in [38] for industrial customers and in [40] for commercial customers, from a Canadian survey. Businesses with available reserve supply (standby generator or battery backup) have considerably larger energy consumption than those without any reserve. The normalized costs were lower for those with a reserve supply than for those without. This is probably due to the higher consumption thus giving lower specific cost when the cost per interruption is divided by consumption.

In the survey reported in [25] the respondents were asked to estimate costs assuming <u>no</u> available reserve. This was due to the fact that the valuation of the reserve supply is based on expectations of future reliability. Reserve investments are not permanent, and cost estimates as a function of availability of reserve supply therefore have certain limitations in use. The literature on this point does not show any unambiguous relation between cost estimates and reserve supply. Reserve supply possibilities should rather be handled specifically when considering particular customers.

The transferability of specific cost estimates from one *geographical* area to another is investigated in [39]. Eight different supply areas are compared in Canada, and considerable variations among the areas are observed. As mentioned earlier, customer cost estimates have a local characteristic and are based on the existing reliability level which may be different from region to region. Cost estimates as a function of geographical regions are neither reported in the Norwegian nor the Nordic survey, but the results from the Nordic survey showed some large differences among the Nordic countries.

In the Norwegian survey the residential specific cost estimates (willingness to pay) vary with *demographic* aspects such as dwelling type and degree of urbanization [35]. The cost estimates (normalized costs) for single family houses are lower than for apartments, and the costs are higher in urban areas than in rural areas. These results are confirmed by the Canadian study [39]. However, the residential sector customer damage function (the *average* cost function for the residential sector) in [39] is found to be insensitive to this aspect.

2.3 Methods for estimating annual interruption costs

This section gives a brief overview of the application of specific costs in the assessment of annual interruption costs (IC).

2.3.1 Expectation values

Assessment of total aggregate interruption costs for an area implies the assessment of interruption costs for individual customers and delivery points. To determine the expected annual costs (EIC), the customers' interruption costs would ideally have to be known for any interruption. This would require comprehensive information, and in practice it is necessary to base the calculations on cost estimates such as those provided by customer surveys for different scenarios.

Traditionally EIC is determined in connection with reliability analyses [1], by combining a *reliability model*, a *load model* and a *cost model*. A reliability analysis is necessary to provide predictions of the number of interruptions (λ) and duration (r) for the delivery points (load points). Expected power- (EPNS) and energy not supplied (EENS) are calculated, and EPNS is then multiplied with the specific cost per kW or EENS with the specific cost per kWh. A general formulation of EIC for a delivery point is given in the following:

$$EIC = \lambda P r c_W$$
$$EIC = EENS \cdot c_W \qquad (2.1)$$

where P is the expected load at the delivery point and c_W is the specific cost for energy not supplied.

The variables in Eq. (2.1) are average or expectation values. The interruption time r is a dominant variable since the specific cost is a function of interruption time. The literature shows that the inputs to this formulation have been varying, which means that the calculation of annual expected interruption costs have been based on more or less detailed information. In the simplest version EIC is found for an area using average figures of number and duration of interruptions in the area together with the average load for the area as a whole and the average (composite) specific cost c_W for the average duration r.

[43] and [46] give a comparison of the total aggregate interruption costs calculated in three different ways for various parts of the ‘RBTS’ test system [80]. In the first method (I), EIC is calculated for each *delivery point* in the area by computation of the contribution to EENS and EIC for each and every interruption expected to occur during a year. The expected frequency and duration of each failure giving interruption to the delivery point, in combination with the expected load and the specific interruption cost for each interruption duration are used to obtain the delivery point EIC.

The second method (II) makes use of the average interruption time with the corresponding specific interruption cost for the delivery points. Method III uses the system index CAIDI, the average interruption time for all delivery point interruptions in the area [10], together with the corresponding composite specific cost. The comparison of the three methods is based on the IEAR (Interrupted Energy Assessment Rate) index:

$$IEAR = \frac{EIC}{EENS} \tag{2.2}$$

By comparison with Eq. (2.1) it is seen that the specific cost c_W in Eq. (2.1) corresponds to IEAR when a single delivery point is considered. In general IEAR represents the resulting average specific interruption cost for a given system configuration.

When calculating IEAR, the simplified approximate methods II and III are quite close to each other for different parts of the distribution system, but these methods underestimate IEAR by 35-50 % compared to method I which is based on a detailed calculation for each delivery point. Both an analytical and a Monte Carlo simulation approach are applied, giving approximately the same results. These two techniques are also compared in [45].

The conclusion from this comparison is that the approximate methods do not generally provide good estimates of IEAR and that a detailed calculation of interruption indices per delivery point should be performed. The main reason for this is the varying interruption time for each failure or outage event and the (in general) nonlinear cost curve. This conclusion is supported by [47] which provides results from a study of the effect of interruption time distributions on the annual interruption costs. It is found that using the average interruption duration, large errors in the annual cost can result, if the cost function is nonlinear.

Examples of the utilization of IEAR in cost-benefit analyses at different levels in the power system are given in [44, 49], for example. The assessment of EIC and IEAR involves application of the customer specific cost functions for different durations and implies an *aggregation* of costs for various customers or customer groups. The aggregated cost as a function of duration for different delivery points is established on the basis of SCDF for the different customer sectors connected to the delivery point. The individual SCDFs are weighted with the sector's portion of the energy consumption (or peak demand for short interruptions) to obtain a Composite Customer Damage Function (CCDF) for the delivery point, see for instance [43, 48-49]. The CCDF depends on the customer mix.

In a preliminary study conducted in this work, the objective was to investigate if time dependent correlations between input variables have any influence on the total result. This is reported in [50]. Recent customer surveys show that interruption costs may have a significant time variation, see examples in Fig. 2.4. Analyses of available data from failure statistics show similar variations in failure rates and repair times, and it is well known that such characteristic variations in load profiles occur. The preliminary study indicated that the time dependent patterns may significantly affect the total result (EIC).

2.3.2 Stochastic variations

Conventional reliability evaluation is generally concerned with the expectation (or average) values of the reliability indices. These are the key factors in decisions related to reliability cost/worth. In the last decade or so different authors have put focus on techniques to evaluate the probability distributions associated with the indices to provide additional information about the stochastic variation around the expectations [54-62]. There are both analytical techniques and Monte Carlo simulation techniques for this purpose.

The probability distributions provide information such as the number of interruptions or interruption time greater than specified values and the dispersion in annual interruption costs from year to year for the different delivery points.

Analytical techniques for estimation of distributions are available for distribution systems. In meshed systems it is complicated to generate the probability distributions analytically [54, 55]. Monte Carlo simulations, however, directly provide the stochastic variations in results and is a general procedure for any type of network, for this purpose.

In [54, 55] the influence of the probability distribution of the interruption time on the annual cost is considered, and a Monte Carlo procedure is developed to establish the probability distributions of reliability indices for the delivery points. The probability distribution for the interruption time is used in conjunction with the CDFs to calculate the annual expected interruption costs analytically. Case studies show the importance of using the whole distribution and not only the average interruption time, which is in accordance with the discussion in the previous section.

Different types of probability distributions (exponential and lognormal) for the interruption time are used in these case studies. The distributions give different expectation values for the annual interruption costs. This is due to the nonlinearity of the cost functions. The shape of the probability distribution for the interruption time will therefore affect the degree to which the nonlinear portions of the cost function will contribute to the annual expected costs [54, 55]. This was also found in the studies reported in [47].

SCDF is the traditional cost model applied in the assessment of annual interruption costs and is an average cost function for a customer sector. In [15] a method called the probability distribution approach is described, incorporating the dispersions in the interruption cost data. The conventional customer damage function describes the average normalized costs as a function of duration. Calculation of these average normalized values is often performed by summing the costs for the respondents in the sector and dividing it by the total peak load or energy demand for the sector [16]. This aggregating process suppresses the effect of pairs of high cost estimates and low energy consumption, leading to lower average values than using the individual respondents' normalized costs to calculate average (or mean) values. If the probability distribution approach using the distribution of the respondents' normalized costs is applied instead of the conventional CDF approach, the annual interruption costs and IEAR become significantly larger [15]. Probability distributions are used to describe the dispersion in interruption cost data under the assumption that these kinds of data have a random or stochastic nature.

However, as mentioned in the previous section, the interruption cost estimates are associated with other types of uncertainties than just statistical, due to subjectivity, lack of data on all kinds of interruptions etc. Fuzzy techniques have proven to be useful for the handling of these types of uncertainties. Rather than representing the dispersion in the data basis, the cost function (CDF) can be represented as a fuzzy variable. The fuzzy set theory is applied with success to a great number of problems concerning power systems [63], and there are also a few publications where the interruption cost is represented as a fuzzy variable, such as [64, 65].

2.4 Summary and discussion

There is growing interest in the assessment of power system reliability worth, or the total aggregate interruption costs, as a basis for cost/worth considerations in power system planning, operation and maintenance. A lot of research has been done in recent years in the field of assessing customer interruption costs and in the development of methods for estimating annual costs.

Customer surveys seem to be the preferred method for the estimation of customer interruption costs. These should contain hypothetical questions for different interruption scenarios within the normal ranges of frequencies and durations. The cost valuation should be based on the direct, indirect or contingent approach, or a mix of these, depending on the customer category. Cost estimates are expected costs, predicted for the different scenarios at a *reference* time, and they are *normalized* with peak demand, energy consumption or energy not supplied. Research is limited concerning the *application* of interruption costs, and the kind of planning purposes etc. A description of the problem is partly missing according to this. What should the cost model look like for different purposes and for considerations affecting a single customer, for several customers or a large area? The cost models used consist of SCDFs or CCDFs which normally are cost functions referred to a base case or *reference* time. These cost functions are again average cost estimates for broad customer categories or SIC classes. Results show that there is a large variation in interruption costs between, but also within, the SIC classes.

The cost estimates are associated with uncertainties due to the lack of knowledge on hypothetical interruptions, estimates are partly based on subjective valuations, the customer surveys only cover a selection of interruption scenarios for a selected classification of customers etc. These are inherent uncertainties which characterize these kinds of data.

Uncertainties associated with the application of the cost estimates for the assessment of total annual interruption costs are related to factors such as uncertainties in data from failure and interruption statistics, load data, the use of broad average cost estimates, and not the least the formulation of annual costs (Eq. (2.1)). The methods reported in the literature have represented the main factors affecting the interruption costs due to unexpected interruptions in the formulation, which are (from Section 2.2)

- Duration of interruption
- Power demand/energy consumption
- Type of customer/customer category

One factor which seems to be vital for the interruption cost for particular customer groups is the *time of occurrence*. This aspect is partly included in some of the reliability methods for composite and transmission systems, through the representation of time-varying loads [e.g. 51-53]. Methods representing the time variation in the specific cost together with a time-varying failure rate and repair time are not found reported in the literature.

The assessment of annual interruption costs is made in conjunction with reliability analysis, by a combination of a reliability model, a load model and a cost model. The techniques used can either be based on an analytical approach or a Monte Carlo simulation approach. The total annual costs should be based on detailed calculations of costs for each interruption for each delivery point. The customer mixture in the delivery point is vital for the specific cost as a function of the duration, represented by the CCDF.

The conventional CDF approach will significantly underestimate the annual interruption costs if the aggregate average specific cost is lower than the mean of the individual respondents specific cost for a particular customer category. An alternative approach is to use the probability distributions of the interruption cost data to determine the annual costs and IEAR.

If the stochastic variations and uncertainties in the different input variables are included, this will provide additional information to the expectations. Examples are: the number of interruptions or interruption time greater than specified values and the dispersion in annual interruption costs for the different delivery points.

The main focus of this work is the development of methods to determine annual interruption costs including *time of occurrence* and time dependent patterns as well as the handling of *uncertainties*. The first aspect involves extensions of the reliability model, the load model and the cost model. It is assumed that interruption cost data are available from customer surveys. Data from the Norwegian survey are used as examples. The basic description is given in Chapters 4, 5 and 6.

3 Delivery points and reliability models

This chapter gives a description of the general delivery point, at an aggregated and detailed level. The assessment of interruptions to the delivery point is outlined for the general case, in meshed and radial systems. Determination of power- and energy not supplied is described. The chapter also includes a description of the reliability models that are chosen for the further study of delivery point interruption costs.

3.1 The general delivery point

The definition of *delivery point* is taken from [2, 11]. A delivery point is a busbar (or a point) where electric power is delivered (or may be delivered) to consumers or between different network owners. In [11] it is recommended that interface points between different voltage levels within a utility's own network are regarded as delivery points. Examples of delivery points are shown in Fig. 3.1. The definition is general and practically any point (busbar) in the system could be chosen as a delivery point.

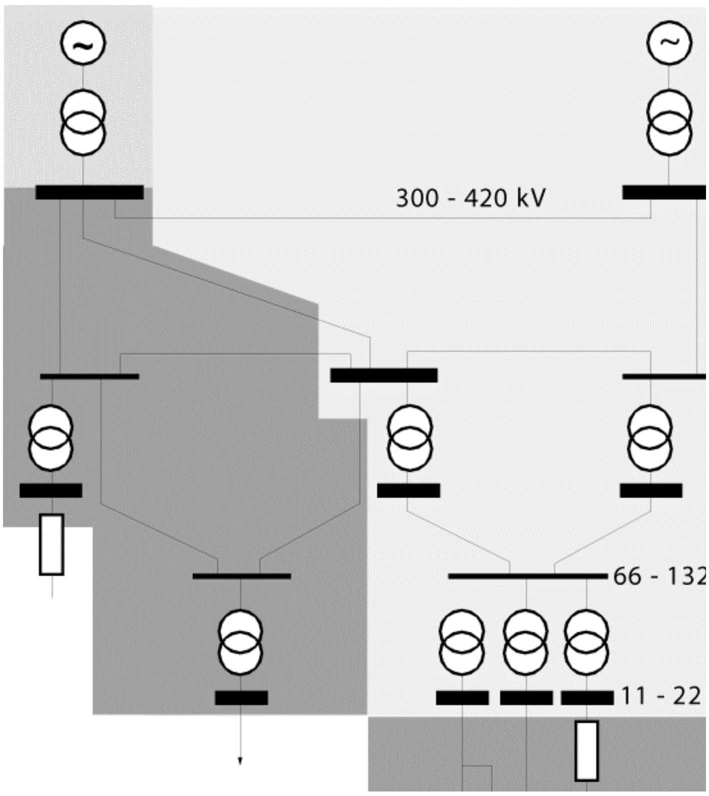


Fig. 3.1 Examples of delivery points.

The delivery point is used in this thesis as the “meeting point” for utilities and customers. The description is included to provide a basis for identification of processes (loads) affected by interruptions and different measures affecting the reliability.

3.1.1 Delivery point description

A single delivery point can represent a load point in the LV, MV or HV distribution system or a load point in the transmission system. Further it can represent either a single customer, a few customers or an interface point to a lower network level, supplying several delivery points or customers. Examples are shown in Fig. 3.2.

A ‘general delivery point’ represents the interface between the utility and a customer. The term is established for the purpose of describing the relation between the supply side and demand side. The term ‘customer’ is extended to represent either an end consumer, another utility (network owner) or a lower system level within the utility’s own network. It may even represent a producer of electricity.

The general delivery point consists of the *supply terminals* [12], loads ($\underline{x}$) and some local generation ($\underline{y}$). The supply terminals represent in this context a fictitious busbar and not necessarily the electrical connecting point for the processes.

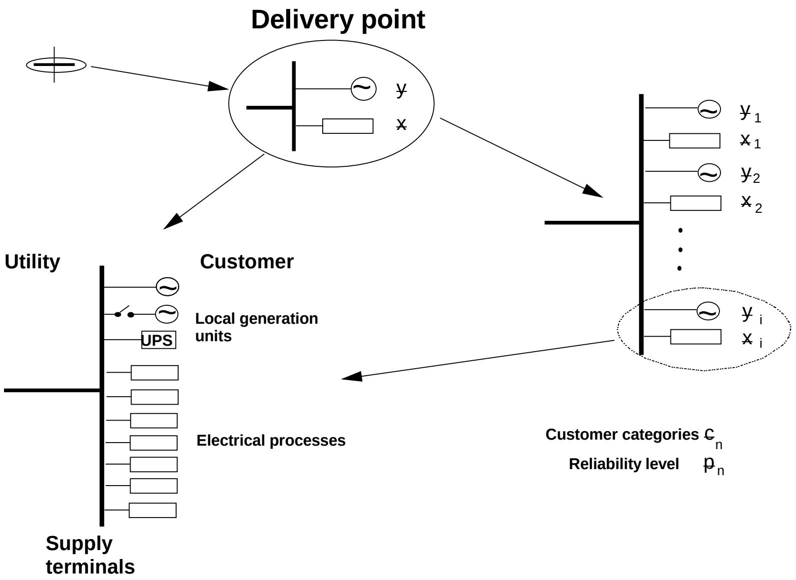


Fig. 3.2 Description of delivery points.

Referring to Fig 3.2, vectors x and y can be interpreted differently whether the decision problem affects a single customer, a single delivery point (with one or more customers), or more than one delivery point.

In case of a single customer (at the lower left of Fig. 3.2) x describes the different *electrical processes*, while y describes the different *local generation units*. ‘Local generation units’ is used as an umbrella term, covering local electric power generation, alternative energy resources and different types of reserve supply units.

For a delivery point supplying more than one customer the x-vector now consists of the various customers connected, at an aggregated level (to the right in Fig. 3.2). This vector will depend on the different customer categories c connected to the delivery point. The y-vector can now represent the equivalent local generation facilities for the delivery point (local generation and reserve supply possibilities).

A bulk supply point (interface point between transmission and HV distribution or HV/MV distribution) represents a delivery point at the most aggregated level (unless there is a single large customer connected). The description to the right in Fig. 3.2 will in this case represent different delivery points at the lower system level. The y-vector represents the local generation in the area or reserve supply from the underlying network (lower network levels).

Each delivery point can be characterized by its specific reliability level p and by different customer categories c.

3.1.2 Reliability: frequency and duration

The reliability level p at the supply terminals is defined by the basic indices:

- number of interruptions (λ)
- duration of interruptions (r).

These variables are determined by outage events in the transmission and distribution system and by the customer’s reserve supply possibilities (y). The reliability level p is therefore determined by both demand side investments and investments in the system (supply side), as well as by maintenance.

The system available capacity (SAC) in the supply network is mainly determined by failures and repair on the components in the system (as will be further outlined in next section). Failures and repair are stochastic variables, as well as the load P and the local generation (LG). Consequently SAC and the reliability level are also stochastic variables. They have a random nature and some typical cyclic variations as shown in Chapter 4. The reliability level can thus be characterized by:

- expectation values of λ and r
- dispersion from the expectation values
- time variation in expectation values.

The dispersions and time variations are included in Chapter 5. The basic principles for determination of the reliability level is considered in the next section.

3.2 Assessment of reliability level

There are numerous models and computer programs for reliability assessment. These can be grouped into Monte Carlo (simulation) methods and analytical methods. Methods for reliability assessment in transmission or meshed systems are quite different from methods in use for distribution or radial systems. The problem of assessing delivery point reliability is nevertheless quite general, even though the developed models and computer programs may be considerably different in type and complexity. This section addresses this generality and some basic principles, while the reliability models chosen for the further study of annual interruption costs are described in Section 3.3.

3.2.1 Interruptions in meshed and radial systems

The occurrence of interruptions depends in general on the available capacity to supply the load P. The available capacity in the supply system is called System Available Capacity (SAC). The available power capacity (APC) at the supply terminals is the sum of SAC and the local generation (LG). *Interruption* occurs when

$$SAC + LG < P \tag{3.1}$$

This is valid in the general case, except when LG represents reserve supply facilities which are connected after interruption has occurred. In such cases interruptions occur when SAC < P, which is usually the case in radial systems. It should be noted here that this is a general and simplified description of the problem of assessing interruptions. Eq. (3.1) represents the stationary situation after dynamic responses have faded away and after possible actions to prevent interruptions or reduce the consequences have taken place.

An example of a system available capacity (SAC)-curve is shown in Fig. 3.3. By superimposing the SAC-curve on the curve for local generation (LG), the available power capacity (APC) profile is obtained (shown in the Fig. 3.3).

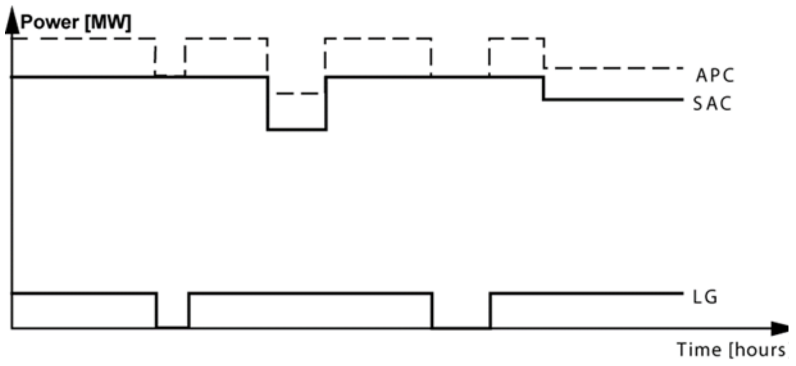


Fig. 3.3 Available capacity models for a general delivery point.

The superimposition of the APC-curve on the hourly load curve gives the available margin. A negative margin implies that load has to be disconnected, giving power- and energy not supplied. The *duration* of the interruptions is given by the periods of negative margins. An example is shown in Fig. 3.4.

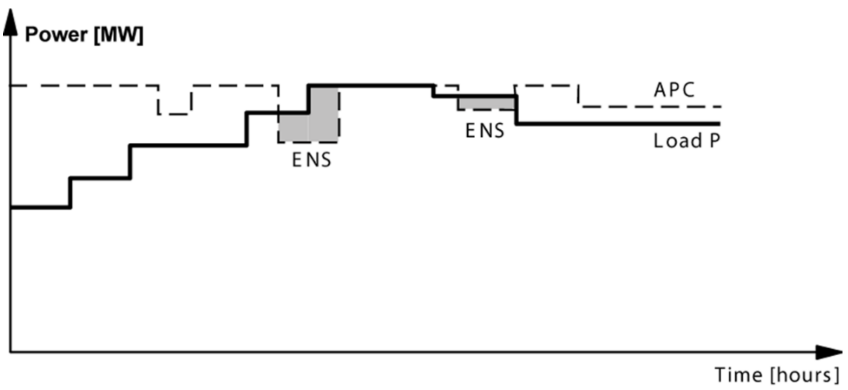


Fig. 3.4 Superimposition of APC-curve on the hourly load curve for a general delivery point.

The procedure described here could be the general approach to the assessment of interruptions. APC is however obtained differently in meshed and radial system.

The simplest way of assessing reliability is for radial distribution systems. Any failure in components in the system will (with very few exceptions) cause interruptions to all the delivery points supplied by the same radial, and the total load is disconnected. It is therefore also quite simple to determine the power not supplied (PNS) and the energy not supplied (ENS).

For composite systems and meshed distribution systems, the reliability assessment is more complicated. Only a few serious contingencies will lead to total interruptions. But any contingency can lead to a reduction in available power capacity to meet the load demand. Depending on the loading conditions and load demands during a contingency, some of the loads may be disconnected due to violation of operating constraints. Corrective actions and preventive measures can be taken, to prevent disconnection of loads or reduce the volume of load curtailments. Examples of such measures are rescheduling of generation, alleviation of overload and load shedding. In radial distribution systems, a preventive measure often used, is alternative supply from reserve connections. If disconnection of loads is necessary, the least critical load may (if possible) be disconnected first and so on.

Since contingencies seldom lead to total interruptions of loads in transmission systems, it is relevant to look at the available power capacity in different time periods. For a bulk delivery point (local area), the situation will be like the one illustrated in Figs. 3.3 - 3.4.

A similar capacity curve can in principle be obtained for a delivery point in a radial distribution system. In a radial system however, for each component failure SAC will be zero, which means that the total load is disconnected. APC however, can be different from zero if there is any reserve supply available. In that case the power will be interrupted, but the amount of ENS will be reduced. Fig. 3.5 shows an SAC-, APC- and a load curve for a delivery point fed from a radially operated system.

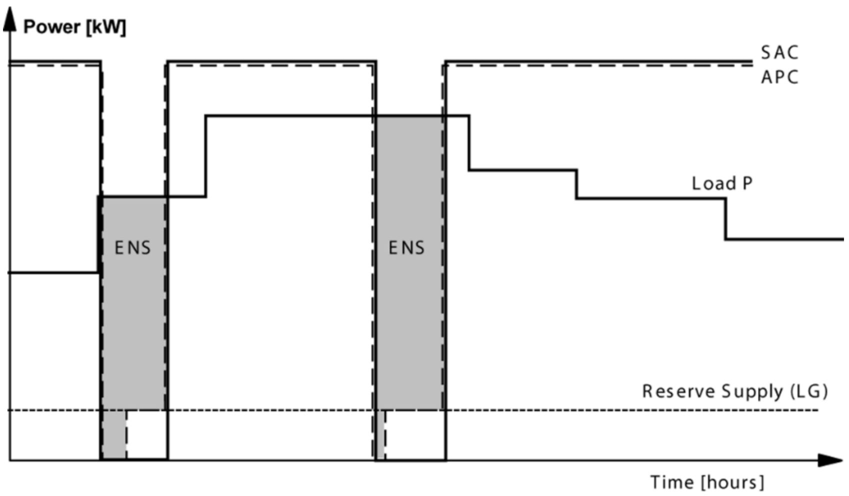


Fig. 3.5 SAC and APC for a distribution delivery point.

Hence for reliability assessment in radial systems, it is not necessary to establish the SAC- and APC-curves to determine PNS and ENS, as will be shown in the next section. Fig. 3.5 is included to show the similarity with the assessment of reliability for a bulk delivery point.

For simplicity SAC is held at a constant level in Figs. 3.3 - 3.5, except in periods of component failure.

3.2.2 System Available Capacity, frequency and duration

SAC is determined by independent and dependent failures on the components in the system, overlap between failures and maintenance, and by system problems (violation of system constraints). The more meshed the system, the more complicated is the determination of SAC and the reliability level. If we consider failures on components only, the SAC profile can be obtained by combining the components' operating cycles, which are established from the stochastic failure/repair process for each component in the system. This is described in [13], and an example with two components is shown in Fig. 3.6. The components are here represented by two states, either up or down.

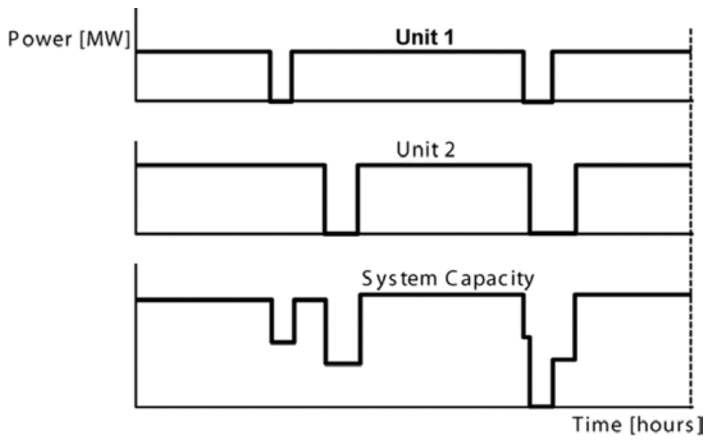


Fig. 3.6 Example of System Available Capacity [13].

In large meshed systems it is too demanding to analyse all possible contingencies. There are different techniques available for screening and ranking the most important or most severe contingencies. Such contingencies are often outages of more than one component, since most systems are dimensioned to withstand outages of one major component ((N-1)-criterion).

All combinations of contingencies that will lead to delivery point interruptions according to Eq. (3.1), can be viewed as the minimum cuts for a particular delivery point. The cuts may consist of :

- single component failures
- double (or more) component failures, independent or dependent
- overlap between failures and maintenance
- system problems (overload, high/low voltage, high/low frequency etc.).

Each cut represents an outage event and will give a certain level of SAC. The occurrence of this level is determined by the equivalent numbers of failures of the cut, λ_{cut}, while the duration is determined by the equivalent duration r_{cut}. If we are able to determine the most important minimum cuts (outage events) and their corresponding SAC, we are able to establish the reliability level. The delivery point's reliability level is in principle given by the following equations:

$$\lambda = \sum_{k=1}^{K} \lambda_{cut_k} \tag{3.2}$$

$$r = \frac{\sum_{k=1}^{K} \lambda_{cut_k} r_{cut_k}}{\sum_{k=1}^{K} \lambda_{cut_k}} \tag{3.3}$$

where K = number of minimum cuts. These formulas are in accordance with the formulas for series systems, given for instance in [10].

The problem of assessing λ_{cut}, r_{cut} and SAC is not considered further. In the following chapters it is assumed that the reliability level can be determined on the basis of the outage events. The contributions from the minimum cuts (outage events) to different reliability indices will be analysed separately and summarized according to the model in Eqs. (3.2) - (3.3). The term "minimum cuts" will be replaced by "outage events" in the following chapters.

3.2.3 Power and energy not supplied

An interruption occurs when the available capacity is unable to match the load. A negative margin (Figs. 3.3 and 3.4) implies that load has to be disconnected. The power not supplied is thus determined by:

$$PNS = P - APC = P - SAC - LG \tag{3.4}$$

Eq. (3.4) might give an optimistic estimate of the power not supplied, as it assumes that it is possible to disconnect only the amount represented by the negative margin.

Examples of energy not supplied (ENS) are shown in Figs. 3.4 and 3.5. In principle ENS should be calculated on the basis of the expected load curve in the interruption time period. In that case the interruption time would give the starting point of the load profile and ENS could be found by integrating the profile during the interruption time. (An eventual higher load after the interruption is not considered.). This is shown in principle in Fig. 3.7 and Eq. (3.5) for the case when the total load is interrupted:

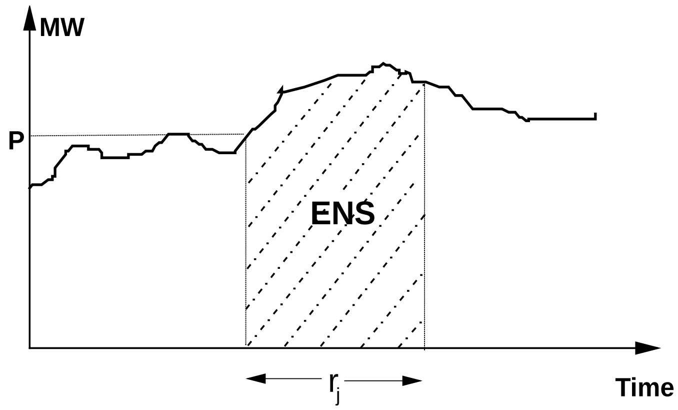


Fig. 3.7 Load curve and energy not supplied.

$$ENS_j = \int_{r_j} P(t)dt \tag{3.5}$$

where:

ENS_j = ENS for interruption no. j
r_j = duration of interruption no. j.

This approach is rather unrealistic due to the extensive amount of data required for each delivery point. A common way of representing the load is by hourly values, i.e. an average load per hour. This leads to approximate integration of ENS.

Using the average hourly values of the load, the expected ENS for the interruption can be determined approximately as shown in Fig. 3.8. ENS can be calculated by summation of the contribution from each interval during the interruption, the contributions being the expected load in the different hours of the interruption:

$$ENS_j = \int_{r_j} P(t)dt = \sum_{i=1}^{I} P_i \cdot \delta r_i \qquad (3.6)$$

where:

- I = number of intervals during r_j
- P_i = average load in interval no. i
- δr_i = duration of interval no. i.

The intervals are equal to one hour, except possibly for the first and last intervals, given a daily load curve with 24 expected values. Eq. (3.6) is valid for the case when the total load is interrupted.

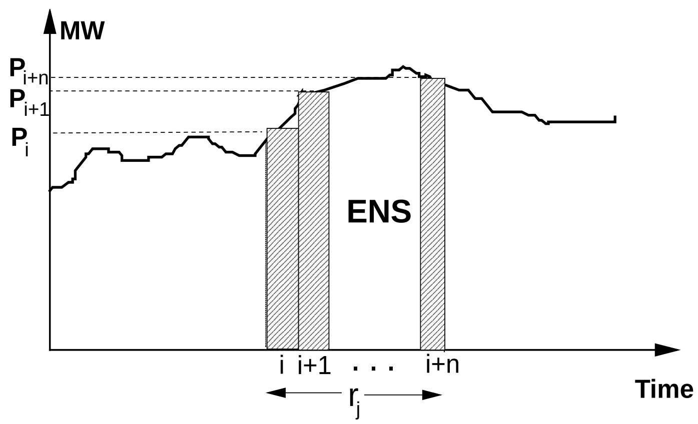


Fig. 3.8 Approximate calculation of energy not supplied (ENS).

3.3 Reliability models

As pointed out, the total interruption costs for a particular delivery point are dependent on the reliability level. A reliability method is required which is able to estimate the number and duration of interruptions. This is conceptually the same matter for any type of transmission/distribution system.

The reliability model chosen for the further study of annual interruption costs is shown in Fig. 3.9. The power system supplying the delivery point is represented by one compact element containing all potential network components between the supply point and the load. Failures of components and other incidents in the system are represented as outage events. In the general case it is assumed that these events may be predetermined by appropriate methods for load flow and contingency analysis. The annual reliability indices are thus found by a *summation of contributions* from different outage events.

For radial systems, however, the reliability and cost assessment will subsequently be based on the radial model RELRAD. RELRAD is described in a paper [9], included in Appendix 1. This model is slightly different from the method presented in [10, Ch. 7]. RELRAD determines the contribution from each component to different delivery points, as opposed to the method in [10] which determines the individual reliability of delivery points directly by the minimum cut sets. Both methods are based on the network topology, and no electrical considerations are included (except for the handling of reserve supply). For the model in Fig. 3.9 the minimum cut set and RELRAD methods will act in the same way. The two methods give the same results for the basic reliability indices described below.

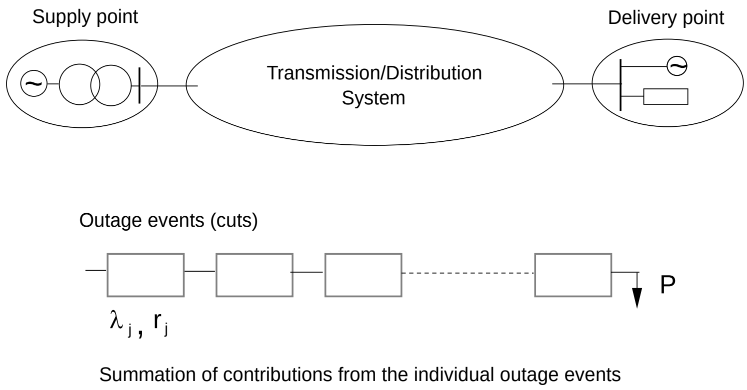


Fig. 3.9 System- and reliability model for estimation of annual interruption costs for a general delivery point.

The basic reliability indices for a delivery point can be obtained using the following equations.

Annual number of interruptions:

$$\lambda = \sum_j \lambda_j \qquad [interrupt./year] \tag{3.7}$$

Annual interruption time:

$$U = \sum_j \lambda_j \cdot r_j \quad [hours/year] \tag{3.8}$$

Average interruption time:

$$r = \frac{U}{\lambda} = \frac{\sum_j \lambda_j r_j}{\sum_j \lambda_j} \quad [hours/interrupt.] \qquad (3.9)$$

where:

λ_j = expected failure rate for component or outage event no. 'j'

r_j = expected repair time for component or outage event no. 'j', or restoration time.

I addition to the basic equations Eqs. (3.7) - (3.9), the expected power not supplied (EPNS) and expected energy not supplied (EENS) can (in principle) easily be determined in radial systems:

Expected power not supplied:

$$EPNS = \lambda P \quad [kW/year] \qquad (3.10)$$

Expected energy not supplied:

$$EENS = UP = \lambda r P \quad [kWh/year] \qquad (3.11)$$

where:

P = expected load at the delivery point.

Eqs. (3.10) and (3.11) are valid for radial systems only and will be modified for meshed systems as described in Chapter 6. Power- and energy not supplied are in the general case determined on the basis of Eqs. (3.1), (3.4) and (3.6). In Eq. (3.6) the total load should be replaced by the load interrupted as a function of time.

It should be noted that the indices given in Eqs. (3.7) - (3.11) are all expectation values. Eqs. (3.10) and (3.11) represent the traditional analytical calculation methods for EPNS and EENS which uses the average values of the variables involved. This method neither includes a representation of uncertainty of any variable nor the time dependency between them.

4 Reliability-, load- and cost data: Characteristics and representation

Available historical data on failures, repair times, loads and interruption costs are presented. The data are taken from Norwegian data bases as examples of typical data for the purposes in this study. Attention is paid to time variation and stochastic variation.

4.1 Time profiles and stochastic variations

A load is characterized by cyclic time behaviour and randomness. It is well known that a load has typical profiles for different load categories, depending on the general activity and climate. The average load level at a particular time is described by such profiles. In addition, the load has a random nature due to varying temperature and activities. This is illustrated in Fig. 4.1 showing the daily load curve for an industrial load. The stochastic variation is given by the standard deviation (sd) in the figure.

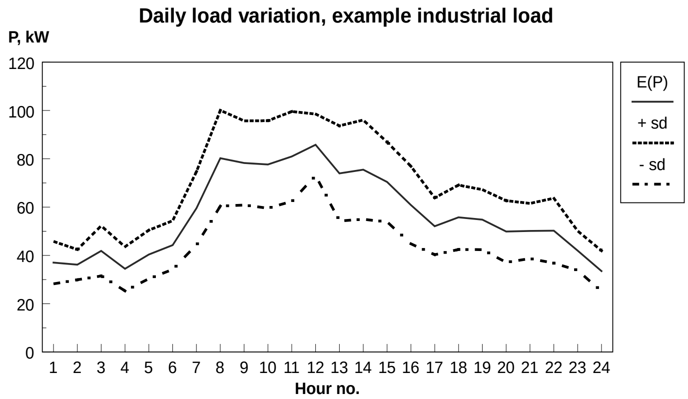


Fig. 4.1 Daily load profile and dispersions for an industrial load.

The expectation E(P) in Fig. 4.1 represents the average cyclic behaviour during the day. The load will follow typical cycles along the time axis both on a daily, weekly and annual basis. Within a year the average load level is time dependent.

The stochastic variation occurs vertical to the time axis, as the load in a particular time period may be higher or lower than the expectation value. The relative dispersion may also vary with time. In principle the stochastic variation might as well be represented by time dependent figures, for instance by a time dependent relative standard deviation.

Similar characteristics are found for failures and restoration times. These are also random variables in the sense that failures occur randomly in the system. Restoration times depend on the types of failures, number of employees on duty, available equipment etc. Reports on failures and interruptions show that failures and restoration times have similar time profiles as the load, showing a time dependency in these variables too. Furthermore recent customer surveys have shown that the same is true for the interruption costs, see example in Fig. 2.4.

The development of models in this work aims to represent both time variations and stochastic variations in the variables determining the annual interruption costs for a general delivery point:

- component failures
- restoration times
- loads
- specific interruption costs.

Time profiles and empirical probability distributions based on available historical data are described in the following sections. It should be noted here that the data presented are examples on available data and not analysed in deep. They will be used as examples in Chapters 7 and 8.

4.2 Failures and repair times

Data on failures and repair times are taken from a 6-year Norwegian database (FAS) comprising about 50 % of the MV distribution system (≤ 40 kV) in Norway. The data is collected for the period 1989 - 1994. From 1995 a new reporting system called FASIT [11] is put into use. Data on failures presented in this section represent failures leading to disturbances. Failures discovered by inspection are not included. Such failures are usually repaired by scheduled maintenance or planned interruptions. The data presented are examples of typical time variation in failures and repair time. Examples of transmission data are given in Chapters 7 and 8.

4.2.1 Failures

Monthly-, weekly- and daily distribution of failures are shown in Fig. 4.2 based on all failures reported in the period. The figure shows the portion of annual number of failures occurring in different months, weekdays and hours respectively.

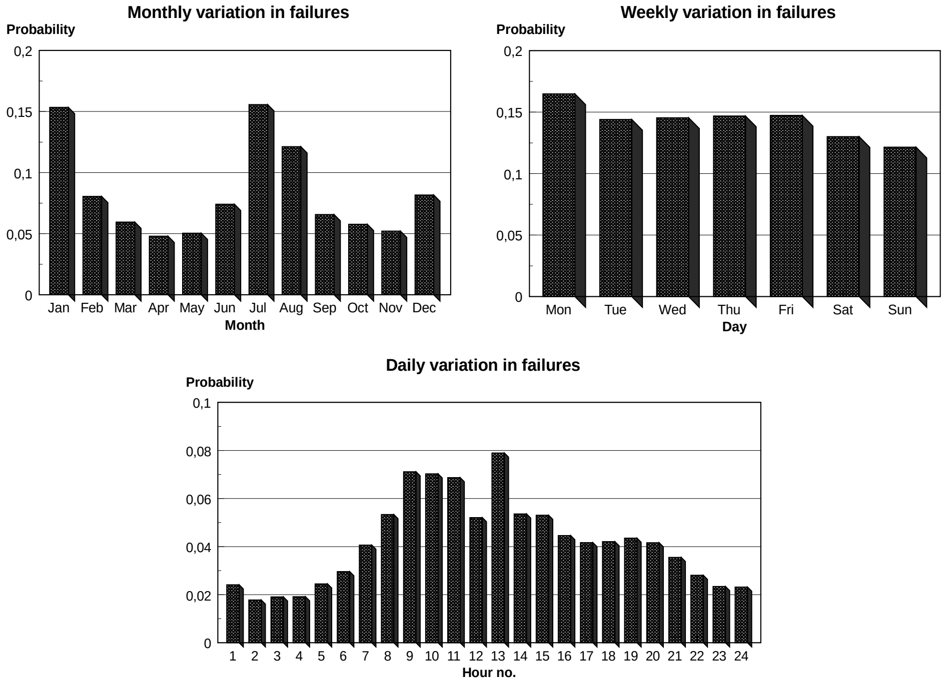


Fig. 4.2 Time variation in failures. All failures 1989 - 1994, MV distribution system (≤ 40 kV).

According to Fig. 4.2 most failures occur in winter (December and January) and in summer (July and August). There are more failures on working days than at the weekend, and most of the failures occur in working hours. This figure indicates that the failure frequency depends on the climate on an annual basis, with typical winter storms and thunder in summer. On a weekly and daily basis the number of failures seem to vary with social activities. In the daily pattern there is a dip in the 12th hour which is lunch time.

Similar histograms for failures on overhead lines and cables are given in Figs. 4.3 and 4.4 respectively. The same pattern over the year can be observed for failures in overhead lines, but the lines are more exposed to winter storms, icing etc. For failures in cables the pattern is smoothed out, with slightly higher probability of failures in the summer months (May - August). The distributions of failures over the week do not show any significant pattern for overhead failures, while failures in cables are likely to occur increasingly during working days with a significant decrease during the weekend. Both for failures in overhead lines and cables the probability of occurrence is highest in working hours with a dip in the 12th hour.

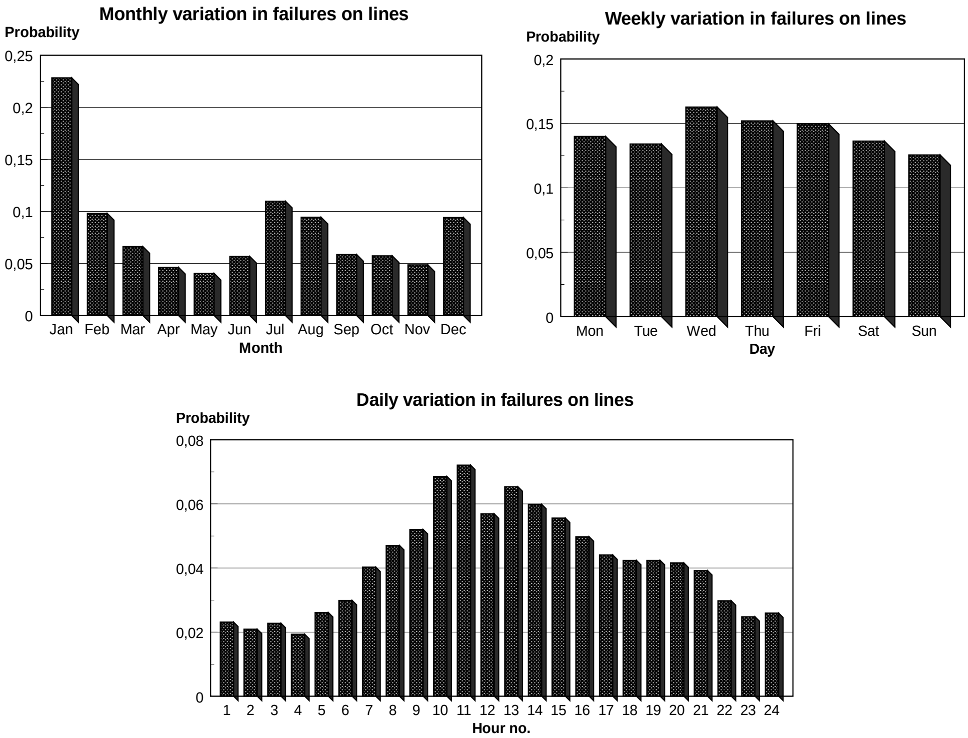


Fig. 4.3 Time variation in overhead failures, 1989 - 1994, MV distribution system (≤ 40 kV).

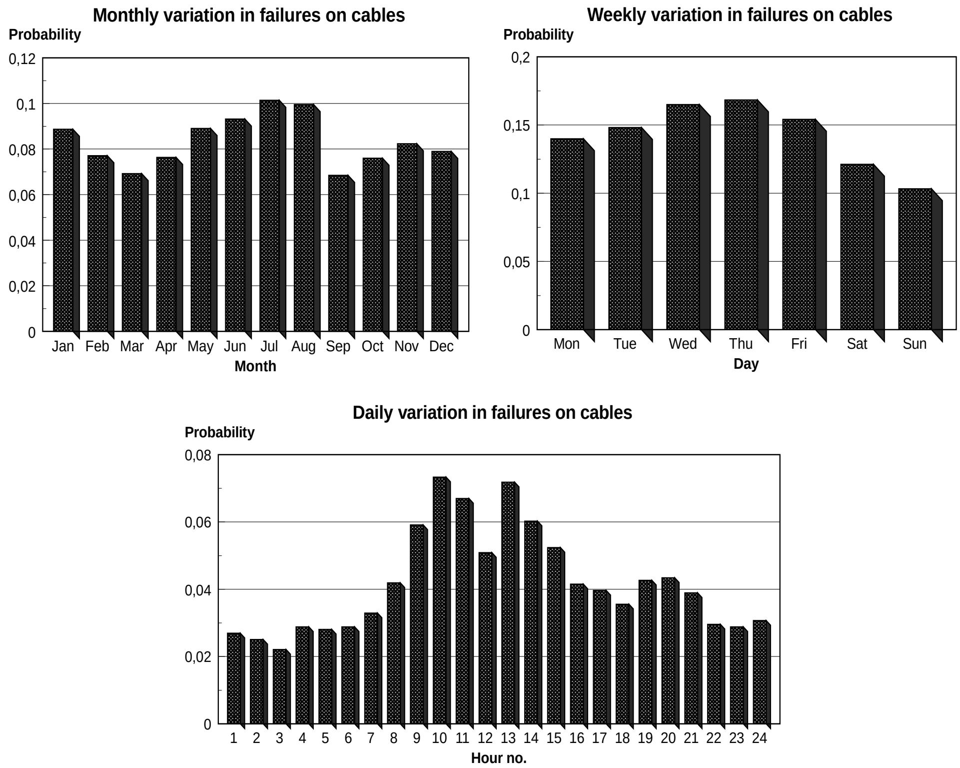


Fig. 4.4 Time variation in cable failures, 1989 - 1994, MV distribution system (≤ 40 kV).

Figs. 4.2 - 4.4 show the cyclic time variation of failures, representing a *varying failure rate* within a year. From year to year the average failure rate can be considered a constant as long as the system is in its normal operating phase. A constant failure rate is in accordance with the assumption that the occurrence of failures agrees with a Poisson distribution. The stochastic variations in failures from year to year is therefore described by a Poisson distribution with the parameter equal to the average failure rate λ_{av}.

4.2.2 Repair time

The interruption time is determined by the restoration procedures after the occurrence of disturbances. The restoration may be performed by automatic breaker reclosure, remote control, manual sectioning, repair or by a mixture of these. In a simulation of the system behaviour upon disturbances and failures, the different restoration times and operating procedures should be considered to obtain a description of the conditions for the different delivery points. A reliability analysis is usually based on a simulation of failures on the components in the system, and we are therefore interested in sectioning times in different parts of the system and repair times for the components.

The available data material does not give separate information on time for sectioning or repair. The restoration times are put in a single variable, representing the mentioned mixture. This variable is an indicator for the interruption time and is in the following also considered as an indicator of the repair time. These data are from now on taken as examples of repair time. FASIT will provide separate information on the different types or parts of the restoration time.

4.2.2.1 Time variation in repair time

Monthly-, weekly- and daily variation in repair time is given in Fig. 4.5 for all distribution failures reported in FAS. The variation is given by relative figures, where the average repair time in each time period (m, d or h) is referred to the annual average r_{av} for all failures.

The long repair times are observed to occur in winter, i.e., in January, February and December. Over the week it seems that the repair time is a little higher at the weekend, while the shortest repair times occur in working hours. Similar diagrams for repair time for failures in overhead lines and cables are given in Fig. 4.6.

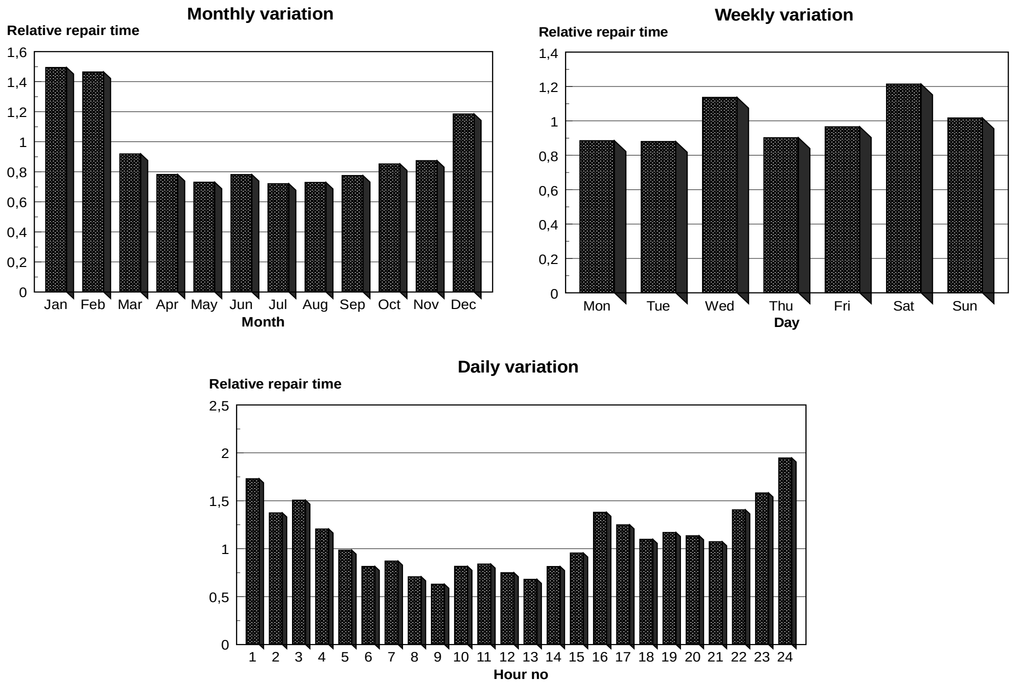


Fig. 4.5 Variation in repair time. All failures 1989 - 1994 (≤ 40 kV).

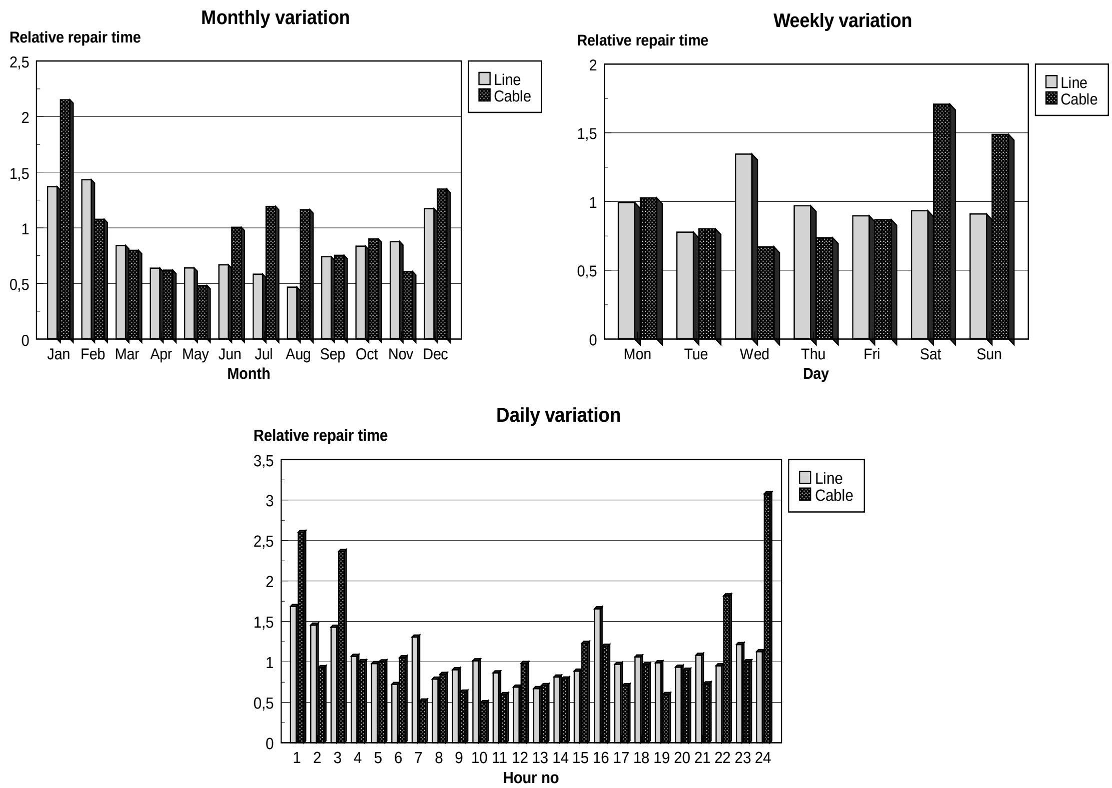


Fig. 4.6 Variation in repair time for overhead lines and cables. 1989 - 1994 (≤ 40 kV).

The variation in repair time is similar to the one in Fig. 4.5 for both cables and overhead lines, with a few exceptions. The repair time for cables is significantly higher (relatively) at weekends and around midnight, and it is higher than the average also in the summer months. Such differences are probably due to the longer times required for the repair of cables than overhead lines. Since there are usually more alternative supply possibilities in cable networks, the repair can be postponed to time periods assumed to be less critical for the consumers. In this context one should keep in mind that the repair time presented in Figs. 4.5 and 4.6 represent a mixture of restoration times and not only time for repair. The top in relative repair time for overhead lines on Wednesdays is hard to explain.

4.2.2.2 Stochastic variation in repair time

A description of the stochastic variations in repair time is similarly based on the limited data presented above, and the mixture of restoration times is considered an indicator for the repair time. The histograms of the reported data for the period 1989 - 1994 are shown in Fig. 4.7 for failures in overhead lines and cables separately. These data are considered examples of typical data in the following chapters.

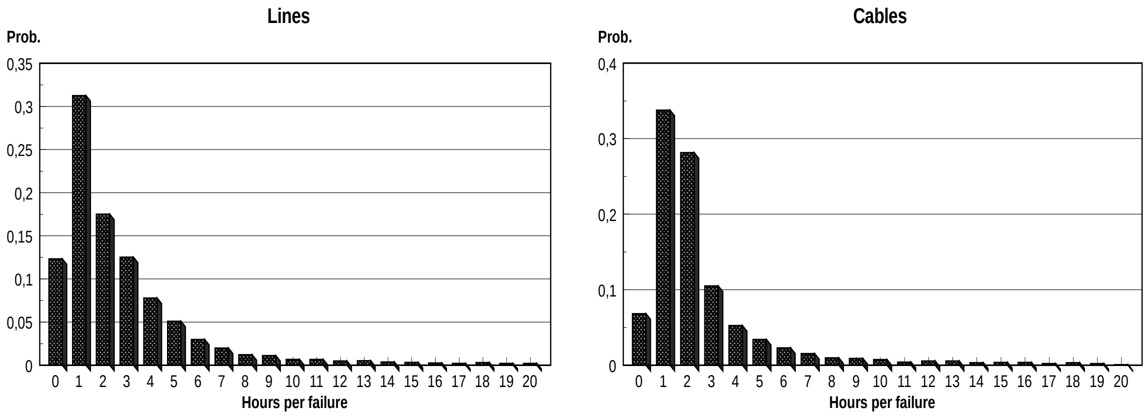


Fig. 4.7 Histogram of repair time, 1989 - 1994 (≤ 40 kV).

Different parametric distributions are fitted to the data given in the histograms. These are the exponential, the Weibull and the lognormal distributions, and the results are given in Fig. 4.8.

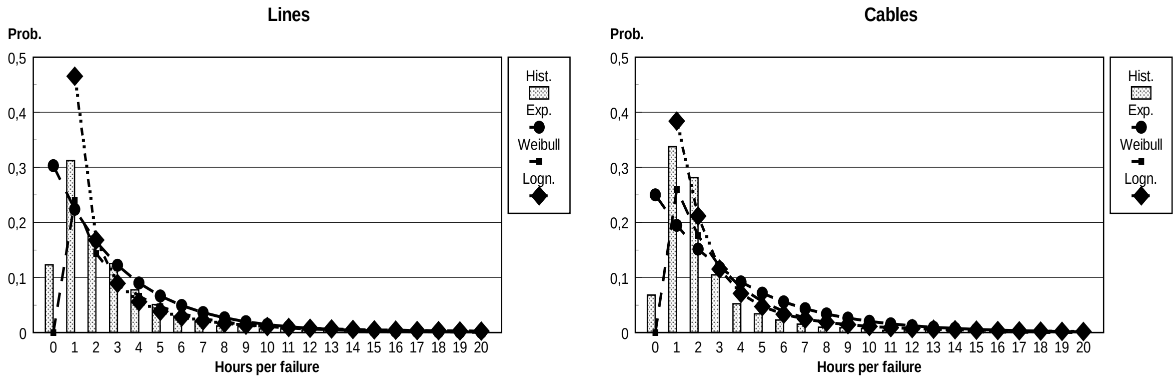


Fig. 4.8 Parametric distributions fitted to the histograms of repair time in Fig. 4.7.

Neither of the parametric distributions seem to fit the data for repair times less than one hour. For longer repair times, the Weibull and lognormal distributions seem to fit the data at best, although the differences are not very significant except for cables. The lognormal distribution seems to follow the histogram for cable repair time best.

As an example of goodness of fit the expectation and the 50 and 90 percentiles are calculated for the fitted distributions. The exponential distribution is shown to give the expectation and 90 percentile closest to the similar statistics calculated from the observed data. However, if the short interruptions (≤ 3 minutes) are excluded from the data base, the repair time is found to be lognormal.

These analyses and the data basis are too limited to draw any conclusions about the distribution of repair time for different components. For simplicity the exponential distribution is used in following chapters to describe the stochastic variations in repair time.

4.3 Loads

The time variation in loads was mentioned in Section 4.1. The availability of data on load registrations differs in the power system. Some industrial and commercial managements have their own load registrations. There are seldom continuous measurements or registrations for delivery points in the distribution system, whereas there are registrations only for some breakers, representing several load points. In the transmission system however, the load is registered continuously, which means that load curves for the individual bulk supply points may be established. This section presents examples of relative load profiles for a single customer and for bulk delivery points.

Stochastic variation in loads are represented by a Normal distribution, which is a common assumption for the load.

4.3.1 Single customers and distribution delivery points

As an example it is chosen to show average load variations for an industrial load with one shift a day and the commercial load by the commodity trade. These data are taken from a database of load registrations for the period 1980 - 1994. The load registrations are performed by the Norwegian Electric Power Research Institute (EFI). This database can be used to establish general load profiles for different types of loads [67]. The industrial and commercial load data presented here will be used as examples in following chapters.

Relative monthly-, weekly- and daily load curves are shown in Fig. 4.9 for industrial loads and in Fig. 4.10 for commercial loads. The daily load variation is referred to P_{max}. The weekly- and monthly variation is referred to the annual average load P_{av}.

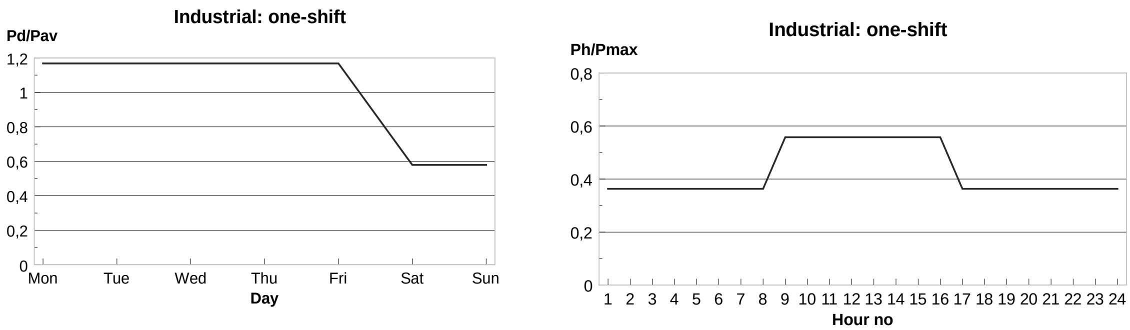


Fig. 4.9 Relative load profiles for industrial loads, type: One shift a day.

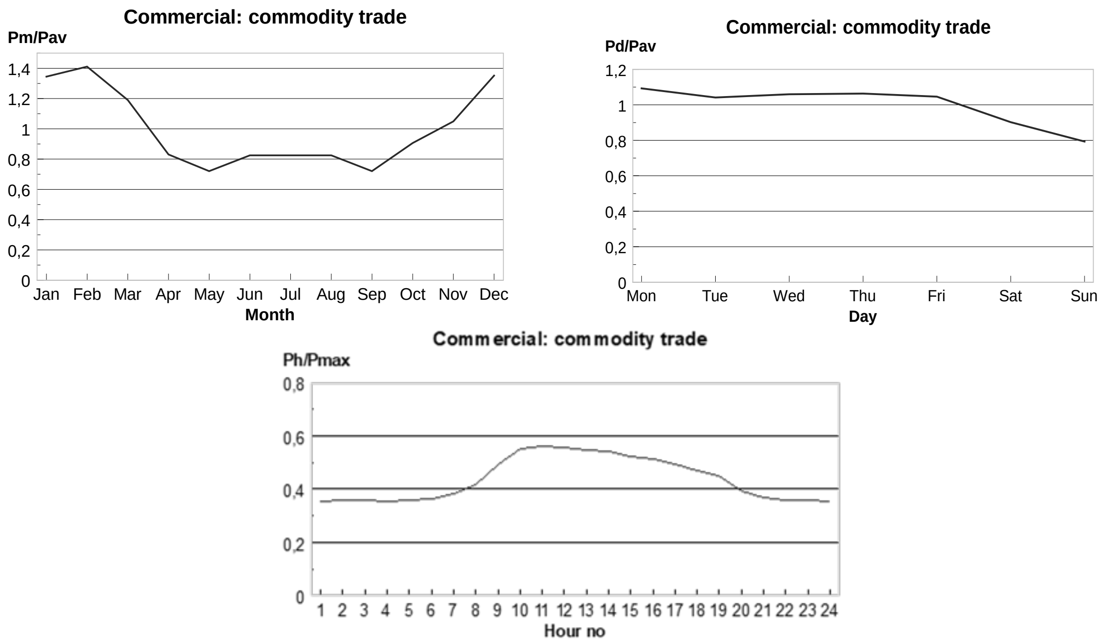


Fig. 4.10 Relative load profiles for commercial loads, type: Commodity trade.

The industrial loads are very diversified. This sector is not homogeneous in the use of electricity and the consumption depends on the climate to a very little extent. Therefore general stylized load curves are established for one-shift, double shift etc. based on load registrations for different types of industrial load. No monthly variation in industrial loads is assumed.

The load factor is approximately 0.43 for both load types, representing a utilization time of approximately 3750 hours. The relative daily load profiles depend on this relation, since they are referred to P_{max}.

Load profiles for distribution delivery points are usually established as general curves based on load registrations for different types of loads. The delivery points may be of an industrial or commercial type or a mixed type with a large residential part for instance.

4.3.2 Bulk delivery point

The example of load variations in a bulk delivery point is taken from a case presented in Chapter 8. The delivery point represents a local area in the southern part of Norway. Relative monthly-, weekly- and daily load variation is shown in Fig. 4.11. These three curves are established on the basis of the expected annual sequential load curve (8760 values) for the area. The relative figures are given in the same way as for the industrial and commercial loads in the previous section.

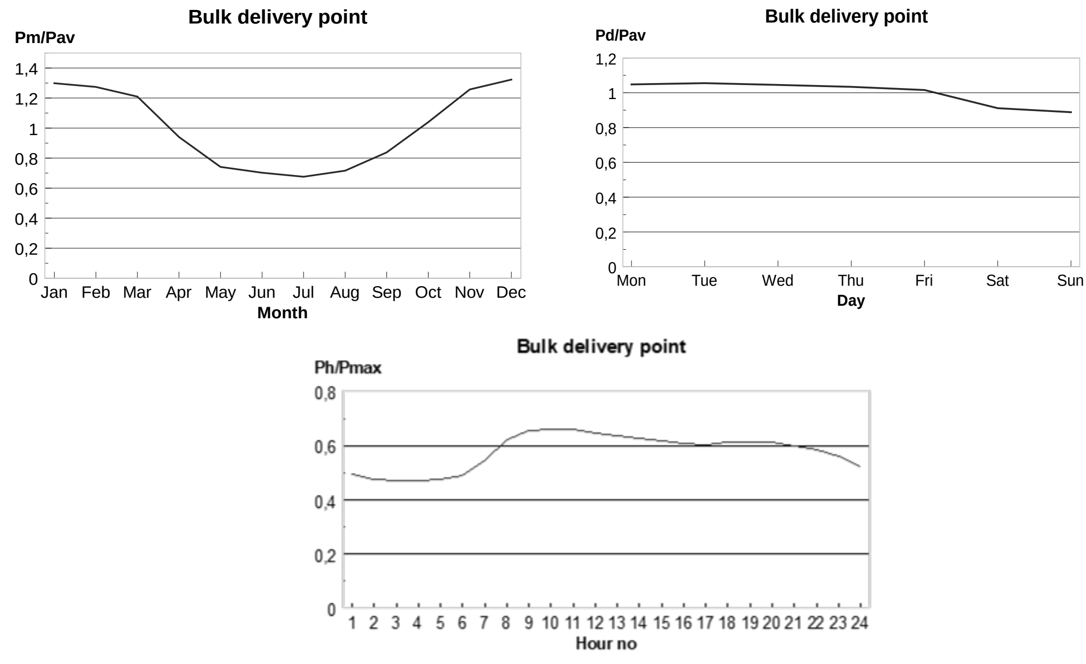


Fig. 4.11 Relative load variation for a bulk delivery point.

The bulk load represents a delivery point at the most aggregated level. The characteristic pattern from the individual loads are retained even at this level, showing the climatical dependency over the year and a load variation depending on the social activities during the day and week.

4.4 Interruption costs

4.4.1 Time variation

An example of time variation in interruption costs is given in Chapter 2, Fig. 2.4. This is taken from the Norwegian customer survey from 1989-1991, and represents the weighted average deviation from the cost at reference time for the commercial sector. In the calculation of annual interruption costs the normalized or specific cost as a function of interruption time will be used in conjunction with power or energy not supplied (see Chapters 2 and 5).

The weighted average variation given in Fig. 2.4 is the deviation in the *cost per interruption*. To obtain the relative variation in the *specific* cost, the relative variation in the normalization factor, which in this case is the energy not supplied, should be considered as well. When the normalization factor is a constant like the maximum load or annual energy consumption, the time variation in interruption cost may be taken care of in a different way. This is discussed in Chapter 6.

Time variation in the specific cost is determined in the following manner. The specific cost c_W for a particular interruption time r is the cost per interruption C(r) divided by the energy not supplied for the interruption EENS(r).

$$c_W(r) = \frac{C(r)}{EENS(r)} \quad [NOK/kWh] \tag{4.1}$$

For a given interruption time r, this is equal to dividing by the product of expected load for the same period and the duration r. The relative time variation in the specific cost is thus given by:

$$\frac{c_{Wj}}{c_{Wref}} = \frac{\dfrac{C_j}{EENS_j}}{\dfrac{C_{ref}}{EENS_{ref}}} = \frac{\dfrac{C_j}{P_j r_j}}{\dfrac{C_{ref}}{P_{ref} r_j}} = \frac{C_j}{C_{ref}} \frac{P_{ref}}{P_j} \tag{4.2}$$

where:

c_{Wj} = specific cost at a particular time j, in NOK/kWh, $c_{Wj} = c_W(r_j)$
C_j = absolute cost at a particular time j, in NOK, $C_j = C(r_j)$
$EENS_j$ = expected energy not supplied at time j, in kWh, $EENS_j = EENS(r_j)$
P_j = expected load at a particular time j, in kW
$EENS_{ref} = P_{ref}\, r_j$.

All variables in Eq. (4.2) are referred to the base case or reference time used in the customer survey. It is seen from this equation that the relative time variation in the specific cost is different from the relative variation in the absolute cost due to the variation in load (P_j).

Since results from the surveys are usually presented as normalized values, the absolute cost C_j (or C_{ref}) is not given explicitly. However some surveys give information on the relative variation in cost per interruption (C_j/C_{ref}). The load P_j at a particular time may be found using the relative profiles in the previous section. The load P_{ref} at reference time is often approximately equal to P_{max}. The cost- and load models used in the further study are described in Chapter 5.

The relative time variation in both specific cost and cost per interruption are given in Fig. 4.12 for industrial loads and Fig. 4.13 for commercial loads. The relative deviation in cost per interruption is given in the customer surveys as discrete values for certain time periods. The variation in specific cost is presented by continuous curves in order to show the difference in time variation between the specific and absolute cost.

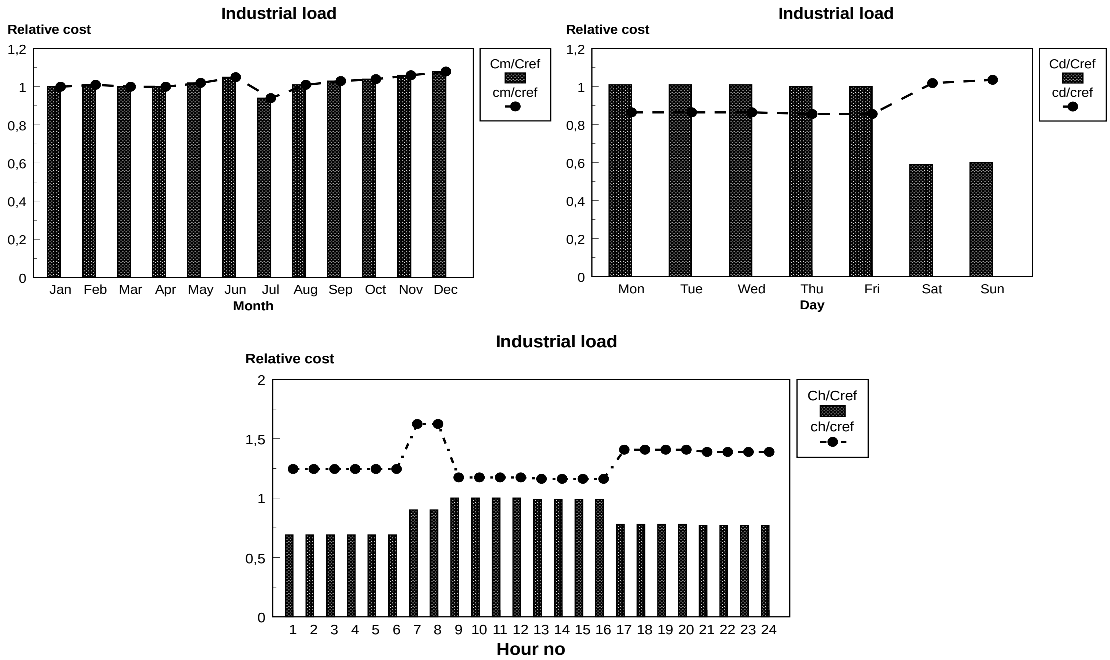


Fig. 4.12 Relative time variation in specific cost and cost per interruption for industrial loads.

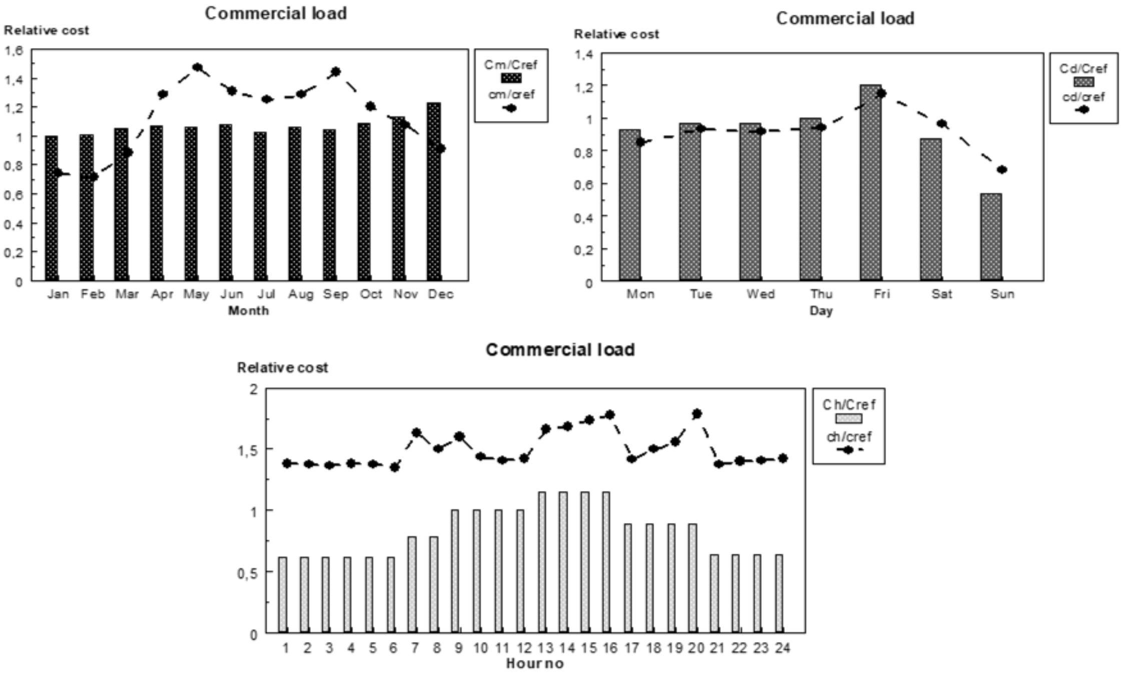


Fig. 4.13 Relative time variation in specific cost and cost per interruption for commercial loads.

The time variation in cost per interruption represents the weighted average for the major industrial and commercial sectors, while the *time variation in specific costs are examples* for industrial and commercial loads using the load profiles from section 4.3.1. The time variation in the specific cost is proportional to the time variation in cost per interruption and inversely proportional to the load profile, and this explains the rather peculiar curves.

It is seen from Fig. 4.12 that the time variation in specific cost for the industrial load coincides with the time variation in cost per interruption due to the constant load on a monthly basis. The average monthly variation in interruption costs for the industrial sector is moderate (within 8 % from the reference cost). The cost is practically equal during working days with an average cost reduction of about 40 % in the weekend. The cost reduction is up to 30 % around midnight.

For the commercial sector the cost variation is larger both on an annual-, weekly- and daily basis. The interruption cost is higher than the January cost in all months, there is a cost increase during the week till Friday which has the highest cost, with an average reduction of nearly 50 % during the weekend. On a daily basis the cost reduction is about 40 % around midnight, and the cost is higher after lunch than at the reference time 10:00 a.m.

The relative curves in Figs. 4.12 and 4.13 can be used to calculate an average interruption cost on an annual basis, referred to the reference cost. These are given in Table 4.1 for both the cost per interruption and the specific cost.

Table 4.1 Average cost per interruption and average specific cost for industrial and commercial loads.

Customer sector	Average cost per interruption	Average specific cost [1)]
Industrial	$C_{av} = 0.76\ C_{ref}$	$c_{Wav} = 1.20\ c_{Wref}$
Commercial	$C_{av} = 0.83\ C_{ref}$	$c_{Wav} = 1.57\ c_{Wref}$

1) These are examples for the two load types in 4.3.1

The large value for the commercial specific cost indicates that there is a large variation in interruption costs as well as a larger load variation for this load type. It should be noted however that the average specific costs in Table 4.1 are based on the particular industrial and commercial loads in Figs. 4.9 and 4.10.

4.4.2 Dispersions in interruption costs

As mentioned in Chapter 2 there are large dispersions in interruption costs within each major customer category, i.e. among the SIC classes, but also within each SIC class. The cost estimates provided by the customer surveys can be presented in a histogram to show this dispersion. An example is given in Fig. 4.14 based on data from the Norwegian survey.

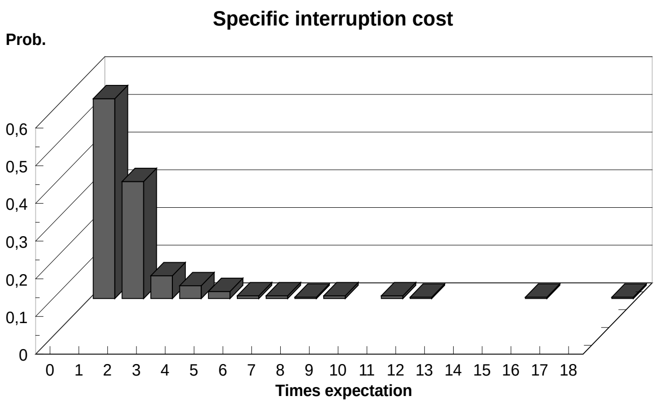


Fig. 4.14 Example of histogram for interruption cost estimates for the industrial sector.

The histogram shows the relative portion of the reported cost as a function of the mean (expectation) value. The form of the distribution is typical for the data collected by customer surveys, with a large portion of the respondents having zero cost, especially for the shorter interruptions. The cost distribution is highly skewed, though the form may vary for different interruption times. This is shown also in [16].

In [15, 16] a probability distribution approach is introduced to describe the dispersion in cost data, and the reported data are transformed to continuous Normal distributions. This is made under the assumption that the cost data are truly random or statistical in nature. For the Norwegian survey any proper probability distribution describing the dispersion in the data has not been evaluated. However, it is possible to use the histograms for each duration as a discrete probability distribution to handle the dispersions. The problem with intermediate durations can be dealt with following the procedure described in [15, 16], if not the same discrete distribution can be used for all durations.

In the development of methods and case studies presented in this thesis, the Normal distribution is selected to describe the dispersions in specific interruption cost, due to its simplicity. The cost data reported for the industrial and commercial sectors are not Normally distributed according to Fig. 4.14. The cost data represent estimates (cost predictions) for a limited number of interruption scenarios and are as such not statistical in nature. Real interruption costs might be random, but interruption costs provided by customer surveys suffer from different types of uncertainties as discussed in Ch. 2.

An example of using the histogram in Fig. 4.14 is included in Ch.7.

5 Estimation of annual interruption costs. Basic description

This chapter gives the foundation for the specific contributions of this thesis. The problem of assessing annual interruption costs and the handling of time variations and uncertainties are described in general. The reliability, load and cost models are presented with the extensions needed to handle time variation and stochastic variations. A general formulation of the annual interruption costs is given.

5.1 Introduction

5.1.1 Problem description

In Value Based Reliability Planning the objective is to determine the *optimum reliability level* and the trade-offs between utility investments and customer investments in short-, medium- and long- term, by minimization of total costs with regard to interruption constraints (Ch. 1). The general optimization problem concerning a delivery point can be described by the following objective function:

$$\min_{\underline{U},\underline{C}} \left(I_U + UAC + I_C + CIC \right) \qquad \underline{g} \leq 0 \tag{5.1}$$

where:

$\underline{U}$	=	Vector of utility reliability measures
$\underline{C}$	=	Vector of customer reliability measures
$\underline{g}$	=	Vector of inequality interruption constraints
I_U	=	Utility investments
I_C	=	Customer investments
UAC	=	Utility Action Costs, depending on the reliability level (λ, r)
CIC	=	Customer Interruption Costs, depending on the reliability level (λ, r).

This equation describes the main cost elements involved in a reliability cost/worth consideration. The investment costs I_U and I_C are the fixed costs representing the *decision variables*, while the variable costs UAC and CIC are the *dependent variables*. UAC represent the utility's direct costs associated with failures and interruptions, such as labour costs and costs of equipment needed for restoration of supply. The variable costs are described in more detail in Appendix 5. In Eq. (5.1) the cost elements represent the discounted costs for a period of analysis.

The *state variables* are primarily the number of interruptions (λ) and the interruption time (r), giving the reliability level. The *constraint set* $\underline{g}$ contains interruption constraints. Actual interruption constraints may be related to a maximum number of interruptions or a maximum interruption time:

$$\lambda \leq \lambda_{max} \Rightarrow \lambda - \lambda_{max} \leq 0$$
$$r \leq r_{max} \Rightarrow r - r_{max} \leq 0$$

The general optimization problem can be stated differently according to the type of decision problem. The above equation represents a local decision problem, where only reliability cost/worth is included in the optimization. For a global decision problem, costs of electrical losses and maintenance costs should also be considered. Decision problems are described in Chapter 8.

The customer interruption cost (CIC) is an essential cost element in the optimization process. The main objective of this work is to provide improved models and methods for estimation of annual interruption costs for delivery points, with emphasis on the handling of time variation and uncertainties in the input variables. The focus is the assessment of CIC, or the annual interruption cost, hereafter called IC.

The assessment of annual interruption costs (IC) involves a combination of a reliability model, a load model and a cost model according to Ch. 1 and [1, 10, 13], for example. The problem to be solved can be stated as the following:

Estimate the annual interruption costs (in the long term) for a general delivery point, given

1) A reliability model
2) A load model
3) A cost model

under consideration of variations with time (day, week and month) and uncertainties in input variables.

The estimation of annual interruption costs implies prediction of future interruption costs in existing and future systems. The predictions are based on historical data for the types of components involved in the particular system solutions under study and available information on interruption cost estimates from customer surveys.

The *delivery point reliability level* (number and duration of interruptions) is adopted as the starting point for the development of calculation methods to estimate annual interruption costs.

The basic representation of reliability level, the load and cost model is given in the next section. Fig. 5.1 gives a schematic presentation of the assessment of annual interruption costs for a general delivery point. Reliability indices that will be determined are given in this figure.

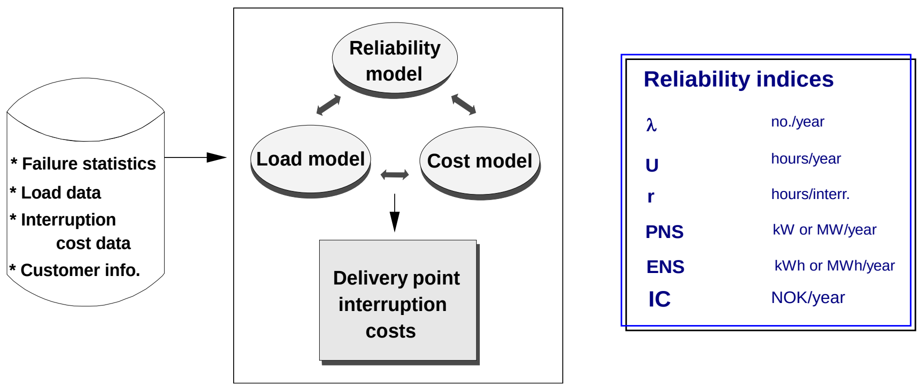


Fig. 5.1 Assessment of annual interruption costs for general delivery points.

5.1.2 Time variation

In Chapter 4 the time dependent patterns in failures are represented as three independent profiles, giving the typical variations with time of the day, day of the week and month of the year. These are average cyclic variations based on observations over several years. The time variation in failures represent the average accumulated effect of all kinds of causes of failure. This way of representing the time-varying failure rate is in analogy with the representation of average load variations. The load profiles are established on the basis of comprehensive load registrations at a particular delivery point or for loads of the same type.

A description of the varying failure rate by such average cyclic variations differs from the classical two- or three weather state description [2, 13]. In a weather-based representation, the occurrence of failures are determined by the estimated weather conditions and different failure rates in normal and adverse weather. This requires both failure data and weather information.

5.1.3 Uncertainties

The classical way of representing uncertainties in a variable is by using probability distributions to describe stochastic variations. The stochastic variation represents the dispersion from the expectation, as illustrated in Fig. 4.1. This variation is statistical in nature, in the sense that a random variable can be measured or registered. The individual observations illustrate the statistical variation in the data.

A statistical representation of the dispersions assumes a certain level of confidence in the average values (expectations). A minimum number of registrations is necessary to provide a degree of certainty about the average or mean value. Adding a description of the stochastic variation gives the dispersions around the mean (expectation), but does not change the mean value as long as the probability distribution used to describe the stochastic variation provides the same expectation.

From this point of view, there is no doubt about the order of magnitude of the average value, or the level of the expectation. Collecting more information may provide more accurate average values, but will not lead to significant changes in the level. Any uncertainty in the expectation may be described by confidence intervals, for example.

For a particular variable we may have little or no confidence in the information available, due to lack of data, lack of knowledge of the nature of the variable, limited number of registrations, data based on subjective judgements, imprecise data due to different interpretations of collecting schemes and so on. In such cases the variable is associated with uncertainties which are not only statistical, and may lead to significant uncertainties in the expectation value itself. For instance only a few observations may give a fuzzy expectation, even if the variable is well-defined and can be properly registered.

As mentioned in Ch. 2 these kinds of uncertainties can be described by fuzzy theory. The basic theory of fuzzy sets is described in [73, 74, 77], for example. Applications of the theory to power systems are described in [63, 72, 75] and in reliability analysis in [71, 79]. The major advantage of this theory is the ability to model human judgements and imprecise data, and the simplicity of the calculation techniques compared to probability calculations.

In fuzzy set theory the concept of possibility is applied (in analogy to the concept of probability). Possibility is like probability defined by a number between zero and one. A fuzzy variable x can be described by a membership function $\mu(x)$ which tells *to which degree* the element x belongs to a fuzzy set *A*. If $\mu(x)$ equals zero, x is definitely not a member of the set, and similarly if $\mu(x)$ equals one, x is completely a member of the set. In probability theory an element *is* a member or *is not* a member of the set. In fuzzy set theory an element can in addition be a member to a certain degree ε [0, 1].

These kinds of uncertainties are dealt with in classical methods by assigning subjective probability distributions to the variables (in analogy to fuzzy memberships). Uncertainties in input variables will be handled both by probability distributions and by fuzzy membership functions. The purpose of this work has been to provide two different representations for the uncertainties in annual costs, depending on the information available. The two descriptions are not combined. However this might be possible, by for instance representing repair times and loads as stochastic variables and the specific interruption cost as a fuzzy variable.

5.2 Reliability, load and cost model

5.2.1 Reliability model and reliability indices

The reliability model chosen for the assessment of delivery point reliability is described in Chapter 3. The development of methods for estimation of IC is based in the general case on a list of outage events (minimum cuts). These may lead to interruptions at the delivery point for certain loading conditions. The outage events are represented by failures on the individual components for radial systems, while for meshed systems the possible outage events are assumed to be predetermined by load flow and contingency analyses.

This work has not been concerned with how to derive the minimum cuts or outage events (critical contingencies). It is assumed that these can be determined by other methods or combination of methods. There are highly developed methods available for this purpose, these are both analytical and Monte Carlo methods [1, 2].

This approach allows the reliability and cost assessment to be decoupled from time-consuming load flow analyses. The estimation of IC starts with the assessment of the reliability level of the delivery point from the outage events. The reliability level is found by simulating different outages and registering interruptions and durations determined by the equivalent failure rates and repair times for the outage events. Annual interruption costs can thus be found by summation of the contributions from individual outage events, according to the model presented in Ch. 3.

The reliability indices (interruption indices) to be calculated are those presented in Section 3.3:

-	Annual number of interruptions	λ	(numbers per year)
-	Annual interruption time	U	(hours per year)
-	Average interruption time	r	(hours per interruption)
-	Annual power not supplied	PNS	(kW or MW per year)
-	Annual energy not supplied	ENS	(kWh or MWh per year)
-	Annual interruption costs	IC	(NOK per year).

The presentation in this chapter will emphasize the annual interruption costs (IC) since this is the main focus of the work.

5.2.2 Reliability level - basic representation

The reliability level is defined in Chapter 3:

- number of interruptions (λ)
- duration of interruptions (r).

The number of interruptions is determined by a sum of contributions from failures of the components involved in a particular system or other outage events. For the estimation of annual interruption costs in the long run, the period of analysis is considered to have a constant average failure rate λ from year to year. Thus the failures occur according to a homogeneous Poisson process (hP). The number of failures per year has a Poisson distribution, with parameter λt (t = 1):

$$P(X = x) = \frac{(\lambda t)^x e^{-\lambda t}}{x!} \tag{5.2}$$

where X = number of failures per year.

A hP-process is characterized by having *independent* and *stationary* increments and there are no simultaneous increments. (If the time intervals are small enough the last assumption will be true). The number of events are Poisson distributed, and the inter-arrival times are exponentially distributed. The events can therefore be sampled by drawing the time to next event from an exponential distribution with parameter λ. This is a common assumption used in reliability assessment of power systems, for instance in Monte Carlo methods [13].

We have observed (Ch. 4) that even though the failure rate λ is constant from year to year there are cyclical and seasonal variation within each year due to varying social and climatic behaviour. The number of events in a year therefore cannot be assumed to be uniformly distributed, since the probability of occurrence in a particular month, on a particular weekday or a time of the day is varying through the year. On a short term (one year) this can be characterized as being a non-homogeneous Poisson (nhP) process with a time-varying failure rate λ(t). The nhP has *independent* but *non-stationary* increments, and the inter-arrival times are not identically distributed.

The combination of short- and long- term considerations to describe the stochastic variations from year to year and the cyclical and seasonal time variation within a year gives a combination of an hP and an nhP process:

Let event *A* be the occurrence of one or more failures in a year. The probability of *A* is (from the Poisson distribution):

$$P(A) = P(X \geq 1) = 1 - P(X < 1) = 1 - P(X = 0) = 1 - e^{-\lambda t}, t = 1\ year \quad (5.3)$$

The timing of failures (or interruptions) within a year is determined in the following way:

A year is divided into time units according to the cyclic (load) variations on daily, weekly and monthly basis:

- daily variation, 24 values (per year)
- weekly variation, 7 values (per year)
- monthly variation, 12 values (per year)

giving 24·7·12 = 2016 time units, one unit being one hour.

The expected number of failures at a specific time, $\lambda_{h,d,m}$, is given by the proportion of the *annual* number of failures occurring in the particular hour (h), weekday (d) or month (m):

$$q_{\lambda h} = \frac{\lambda_h}{\lambda_{av}} = \frac{\lambda_h}{\sum_{h=1}^{24} \lambda_h}, \sum_{h=1}^{24} q_{\lambda h} = 1.0$$

$$q_{\lambda d} = \frac{\lambda_d}{\lambda_{av}} = \frac{\lambda_d}{\sum_{d=1}^{7} \lambda_d}, \sum_{d=1}^{7} q_{\lambda d} = 1.0 \quad (5.4)$$

$$q_{\lambda m} = \frac{\lambda_m}{\lambda_{av}} = \frac{\lambda_m}{\sum_{m=1}^{12} \lambda_m}, \sum_{m=1}^{12} q_{\lambda m} = 1.0$$

such that

$$\lambda_{h,d,m} = \frac{\lambda_h}{\lambda_{av}} \frac{\lambda_d}{\lambda_{av}} \frac{\lambda_m}{\lambda_{av}} \lambda_{av} \quad (5.5)$$

where λ_{av} is the annual average number of failures. Eq. (5.5) gives the number of failures occurring in a particular time period (h, d, m) of the year, in the long run. In $\lambda_{h,d,m}$ all types of failures are included, i.e., failures caused by climatic, technical or other conditions such as human. It represents an average variation based on the available observations.

The relative failure rates 'q_λ' in Eq. (5.4) are interpreted as the conditional probabilities of having failures in hour (h), on weekday (d) and in month (m) respectively. These probabilities are assumed to be independent:

Let event *B* be the occurrence of failures in hour 'h', on weekday 'd' and in month 'm'. We are interested in the probability of event *(B)* conditioned on *(A)*, i.e., given that certain failures occur in the actual year. This probability is given by:

$$P(B \mid A) = q_{\lambda h} q_{\lambda d} q_{\lambda m} \tag{5.6}$$

The conditional probabilities are given as discrete figures, representing the probability distributions used for the timing of interruptions.

The time variation in the repair time of components or outage events is represented by a similar cyclic variation as the number of interruptions, with relative variation referred to the annual average duration. For an interruption occurring in hour (h), on weekday (d) and in month (m), the expected repair time is:

$$r_{h,d,m} = \frac{r_h}{r_{av}} \frac{r_d}{r_{av}} \frac{r_m}{r_{av}} r_{av} \tag{5.7}$$

where:

- r_h = expected repair time for hours (h), independent of the weekday and the month
- r_d = expected repair time on weekdays (d), independent of the month
- r_m = expected repair time in months (m)
- r_{av} = annual average repair time.

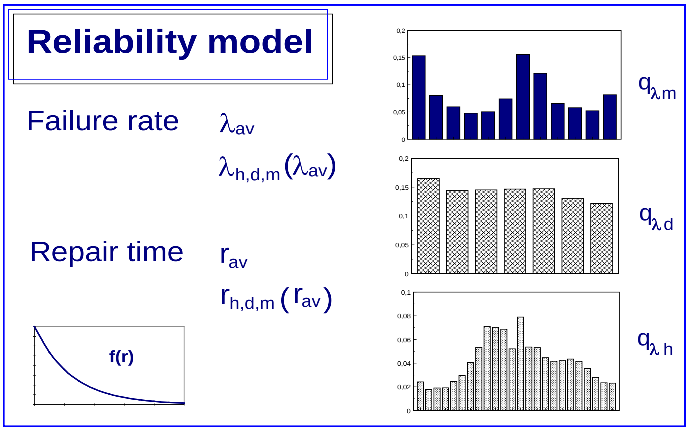


Fig. 5.2 Reliability model.

The reliability model is extended by inclusion of the three independent time profiles. The model is shown in Fig. 5.2. The stochastic variation in the repair time can be represented by an appropriate probability distribution. The *exponential distribution* is chosen for the development of the models.

5.2.3 Load model

The basic representation of the load is to use relative load profiles in analogy with the variation in failures. These are independent daily-, weekly- and monthly load profiles, based on hourly values for the load. The profiles are relative, referred to the annual maximum load and the annual average load respectively. For an interruption occurring in hour (h), on weekday (d) and in month (m), the expected load is:

$$P_{h,d,m} = \frac{P_h}{P_{\max}} \frac{P_d}{P_{av}} \frac{P_m}{P_{av}} P_{\max} \tag{5.8}$$

where:

- P_h = average load in hours (h), independent of the weekday and the month
- P_d = average load on weekdays (d), independent of the month
- P_m = average load in months (m) for a given temperature
- P_{max} = the annual maximum load
- P_{av} = the annual average load.

Alternatively, the time variation in load can be represented by separate daily profiles for working days and weekends:

$$\begin{aligned} P_{h,d,m} &= \frac{P_{h(wd)}}{P_{\max}} \frac{P_m}{P_{av}} P_{\max} \quad d = 1,...,5 \\ P_{h,d,m} &= \frac{P_{h(we)}}{P_{\max}} \frac{P_m}{P_{av}} P_{\max} \quad d = 6,7 \end{aligned} \tag{5.9}$$

where:

- $P_{h\,(wd)}$ = average load in hours (h) on working days
- $P_{h\,(we)}$ = average load in hours (h) at weekends.

In the following the representation in Eq. (5.8) will be used. Stochastic variations are represented by the Normal distribution.

The load model is shown in Fig. 5.3.

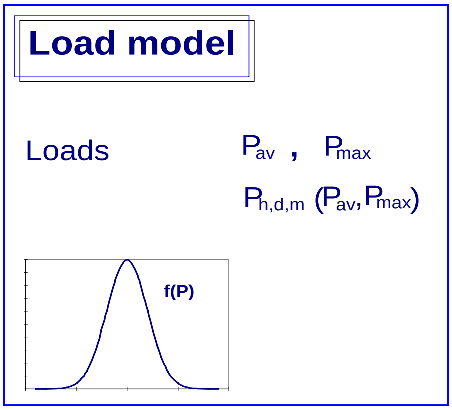


Fig. 5.3 Load model.

5.2.4 Cost model

The expectation of the specific interruption cost c_W for a given duration is represented in a similar manner as the other variables, by three independent time profiles:

$$c_{W\,h,d,m} = \frac{c_{Wh}}{c_{Wref}} \frac{c_{Wd}}{c_{Wref}} \frac{c_{Wm}}{c_{Wref}} c_{Wref} \qquad (5.10)$$

The profiles are relative, referred to the specific cost at reference time (cfr. Chapters 2 and 4). The relative profiles are determined from the relative time variation in the cost per interruption, like it is shown in Section 4.4, Eq. (4.2). The specific cost at reference time is found from the Customer Damage Function for the delivery point. The same relative profiles for any interruption time r are assumed. The cost model is shown in Fig. 5.4. A Normal distribution is initially assumed for the interruption costs for the general description of dispersions.

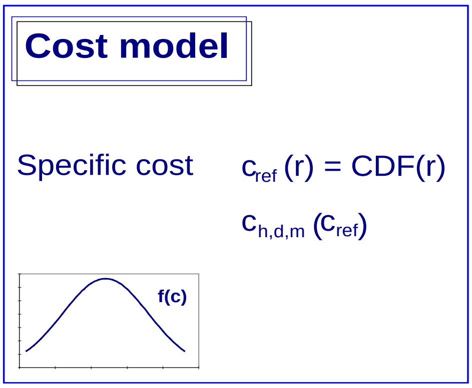


Fig. 5.4 Cost model.

5.3 Annual interruption costs

This section gives a formulation of the annual costs (IC) for a general delivery point, based on a *radial reliability model*. The delivery point is considered a “black box”, meaning that different customers, customer groups or types of loads are not considered. These aspects are included in Section 6.5 in the generalization of the model.

The annual interruption costs for a delivery point are according to Chapter 2, generally determined by the number (λ), duration (r) and time of occurrence (h, d, m) of interruptions during a year, and by the cost per interruption (C). The reliability level (λ, r) is determined by a sum of contributions from failures in different network components and other outage events in the system.

If information of costs per interruption were available, the calculation of annual interruption costs would be a matter of counting incidents, estimate the time of occurrence and duration and accumulate the costs per interruption. However, data on customer interruption costs are given as normalized values or specific costs for major customer groups, referred to a demand (P) or a volume (ENS). The cost estimates are referred to a base case or reference time. In traditional methods the calculation of annual costs is based on assessment of energy not supplied (ENS), connecting a specific cost (c_W) for that volume.

The formulation of annual costs is in the following based on such normalized costs for different interruptions, and makes use of *specific* costs referred to energy not supplied like in the Norwegian survey (see Ch. 2). A formulation based on the absolute cost per interruption is included in Section 6.5.

5.3.1 Formulation of annual expected interruption costs

If the customers’ costs of interruptions were known for any interruption scenario, i.e., for interruptions occurring at random times and of random duration, the actual annual costs could be expressed as:

$$IC = \sum_j C_j = \sum_j P_j \, r_j \, c_W(r_j) \quad [NOK/year] \tag{5.11}$$

where:

IC	=	annual interruption costs
j	=	variable describing *actual* interruptions
C_j	=	cost of interruption no. ‘j’ in NOK
r_j	=	duration of interruption no. ‘j’

P_j = actual interrupted load for interruption no. ‘j’
$c_W(r_j)$ = specific cost for interruption no ‘j’ in NOK/kWh.

Eq. (5.11) requires an extensive amount of information, as it uses the *actual* values of the variables for each and every interruption. In practice it is necessary to base the calculations on available information, which means historical data on failures and repair/restoration times, load registrations and load forecasts, and the limited information on interruption costs from customer surveys.

The simplest analytical expression for the annual expected interruption costs EIC is the multiplication of *expectation* values of the variables involved, by calculating expected energy not supplied from Eq. (3.11) for a radial model, and then multiply by the specific interruption cost:

$$\begin{aligned} EENS &= \lambda P r \\ EIC &= EENS\ c_W \end{aligned} \qquad (5.12)$$

where:

λ = annual number of failures (interruptions)
P = average load
r = average duration of interruption
c_W = expected specific interruption cost for average duration.

Eq. (5.12) is only valid for delivery points in radial systems, where each failure (disturbance) leads to interruption of the total load P.

5.3.2 Aspects to be included in the cost description

The expected *number* of interruptions per year (λ) in Eq. (5.12) is one of the two elements defining the reliability level. Also the *duration* of interruptions (r) is included, but only the average for all interruptions. As the duration is of high importance for the interruption cost, Eq. (5.12) should be extended to include this aspect:

$$EIC = \sum_j P\, r_j\, c_W(r_j) \qquad (5.13)$$

where:

r_j = expected duration of interruption no. ‘j’
$c_W(r_j)$ = expected specific cost for duration r_j.

Equation (5.13) can be solved by simulating failures on the different components (or minimum cuts) involved, e.g. using the RELRAD model [9] for radial systems. The duration r_j is determined by repair of the failed component or restoration of supply to the delivery point by switching operations.

To incorporate the time variation and possible time dependent correlation in the variables involved in the annual interruption costs, the expectation value EIC should be determined by solving the expected product of the variables in Eq. (5.12):

$$EIC = E(\lambda P r \, c_W(r)) \tag{5.14}$$

Using the definition of the expectation and the probabilities from Eqs. (5.4) and (5.6), and including the individual durations, this can be further expressed as in Eq. (5.15):

$$E(\lambda P r \, c_W(r)) = \lambda \sum_{k=1}^{2016} P_k \, r_k \, c_{Wk}(r_k) \, q_{\lambda k} \tag{5.15}$$

where:

- λ = the average annual rate
- k = time period (hour) no.
- P_k = expected load in period k
- r_k = expected duration in period k
- c_{Wk} = expected specific interruption cost in period k for duration r_k
- $q_{\lambda k}$ = probability of failures in period k (Eq. (5.6)).

Eq. (5.15) represents an extension of both Eqs. (5.12) and (5.13) by the inclusion of time variation. This formula is a general representation according to a radial model. Practical methods for estimation of the expectation in Eq. (5.15) are given in Chapter 6 both for radial and meshed systems.

In order to solve Eq. (5.15) we need corresponding values of the variables, and we need a lot more information than for the solution of Eqs.(5.12) and (5.13). In Eq. (5.15) the *time of occurrence* is a key parameter. This determines the value of the load, the duration and the specific cost to be used in the solution process, due to the time dependency between occurrence of failures and the other variables.

5.4 Stochastic variations and fuzziness

The most important aspects or characteristics of interruptions for a general delivery point are included in the previous section, in Eq. (5.15). We have been able to represent the time variation and the eventual time dependency between the variables. Two questions are now raised: How can we represent the uncertainties due to stochastic variations and fuzziness, and how can we combine these with the time variation?

5.4.1 Handling of stochastic variations

The time variation in variables is represented by the time-varying average values. The stochastic variation occurs vertical to the time axis and may be different in different time periods.

If the annual costs and the variables in the cost function in Eq. (5.15) are described as stochastic variables, they can be represented by their probability distributions. The probability distributions give information on the possible values of the variables and the probabilities of different outcomes. The probability distribution of the annual costs is in general given by the following expression:

$$F_{IC} = \int_{IC} f_{IC}(\lambda, P, r, c_W)\, d_{IC} \qquad (5.16)$$

where:

F_{IC} = cumulative distribution function for annual interruption costs

f_{IC} = probability density function for annual interruption costs.

Since the annual costs are a function of four stochastic variables, the probability distribution for IC is determined by the convolution of the variables' density functions. The expectation value of IC can be derived from the distribution using the general definition of expectation. This convolution will be too complicated to solve analytically.

A solution for one possible outcome is illustrated in Fig. 5.5. For convenience the probability of occurrence of failures (interruptions) is described by a continuous density. IC_i is the annual interruption cost for outcome no. i, corresponding to one year.

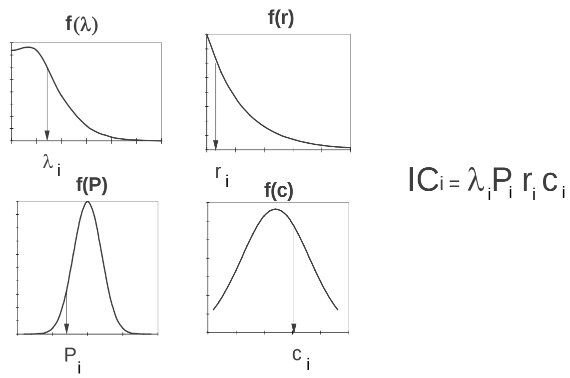


Fig. 5.5 Annual costs for outcome no. i of the variables

The problem can be solved by Monte Carlo simulation, where the solution procedure can be based on this formulation. The convolution is replaced by random drawings from the individual probability distributions, as explained in Section 6.3.

The next step is to combine the stochastic variations and the time variations. The problem can be solved by a two-stage Monte Carlo process:

1) Find the time period ‘k’ (hour, weekday, month) of next interruption ‘j’, based on the probability of occurrence, q_λ from Eqs. (5.4) and (5.6)

2) Determine the variables P_k, r_k and c_k valid for the time period ‘k’ by drawings from the probability distributions

In this process we need separate probability distributions for each time period. An illustration is given in Fig. 5.6, showing the density functions. An interruption occurs in period ‘k’ of year no. ‘i’, with probability $q_{\lambda k}$. The variables are given by the probability densities in period ‘k’. The product represents the contribution from interruption no. ‘j’ to the annual costs IC_i.

The aspect of stochastic variations in failures from year to year is separated from the variations within each year given by the q_λ-factors in Eq. (5.4). In the Monte Carlo process this can be handled by first drawing the number of failures to occur next year from the Poisson distribution, and secondly determine the timing of failures (period ‘k’) from the probability of failures in different time periods. The probability of failures in period k, $q_{\lambda k}$, is assumed constant.

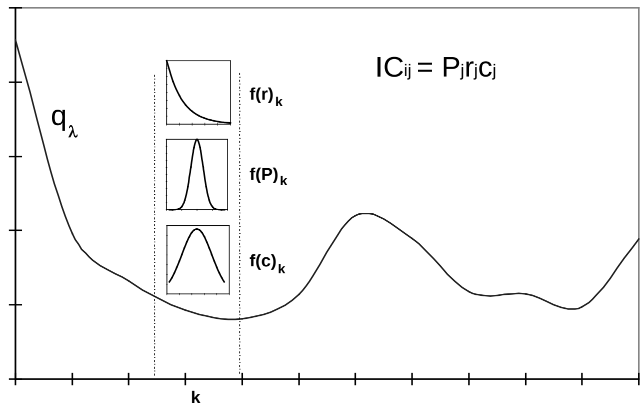


Fig. 5.6 Contribution to the annual costs from interruption no. 'j' for one outcome of the variables.

The Monte Carlo simulation process result in the probability distribution for IC. The distribution gives the dispersion in annual costs from year to year (and from interruption to interruption), adding valuable information to the expectation in Eq. (5.15).

5.4.2 Fuzzy description of uncertainties

In a fuzzy description of uncertainties, the annual costs and input variables in Eq. (5.15) are described as fuzzy variables and represented by fuzzy membership functions. In analogy to the probability distributions these memberships give information about the possible range for each variable and the possibilities of different outcomes.

If the fuzzy set theory and the concepts of possibility are applied to the failure rate, for instance, an expert judgement could be like

> *"The failure rate for component L is at least 0.1 per year and not larger than 0.4. About 0.2 will be the best estimate"*

From this statement we see that it is possible that the failure rate lies between 0.1 and 0.4 with the highest degree of possibility around 0.2. In conventional probability theory the failure rate would have been assigned a crisp value of 0.2, equal to the expectation.

For the repair time a similar statement could be

> *"The repair time for overhead lines is most possibly between 4 and 6 hours. It is never below 2 hours and never more than 10 hours"*

Membership functions, $\mu(x)$, are often established on the basis of linguistic terms like the ones above, or they can be established on the basis of the data available. There are different methods for this reported in the literature. Typical membership functions are triangular and trapezoidal functions, i.e. functions which are described by the four corners a_1, a_2, a_3 and a_4 for a trapezoidal function with $a_2 = a_3$ for a triangular function. Examples are given in Fig. 5.7.

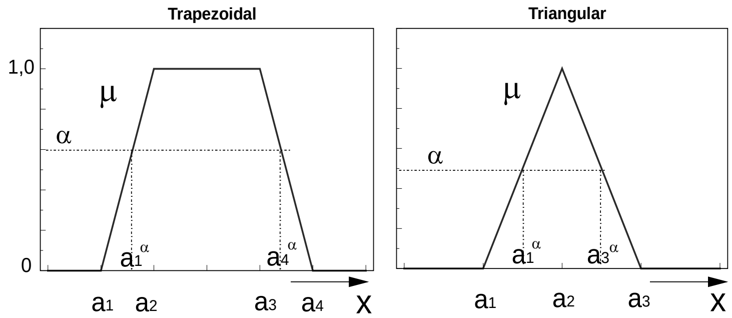


Fig. 5.7 Triangular and trapezoidal membership function.

For a trapezoidal fuzzy number *A*, the following notation is used:

$$A = [\, a_1, a_2, a_3, a_4 \,] \tag{5.17}$$

In the example with the repair time above, $a_1 = 2$, $a_2 = 4$, $a_3 = 6$, $a_4 = 10$.

According to [77] we can define a α-cut which is parallel to the horizontal axis, giving an interval of confidence for the fuzzy number. Examples are given in Fig. 5.7. The fuzzy number can alternatively be represented by the interval of confidence at level α:

$$A_\alpha = [\, a_1^{(\alpha)}, a_4^{(\alpha)} \,] = [(\, a_2 - a_1)\alpha + a_1, -(\, a_4 - a_3)\alpha + a_4 \,] \tag{5.18}$$

Operations on fuzzy numbers can be based on the interval of confidence at each level α. The rules for arithmetic operations on fuzzy numbers are taken from [75, 77]. Addition and subtraction of two fuzzy numbers can be based on the corners of the membership functions. In the nonlinear operations such as in multiplication, the shape of the membership function does not remain trapezoidal, but it is considered a relatively good approximation for practical purposes [75, 77]. Multiplication can be performed correctly using the intervals of confidence as shown in [77].

Examples of summation and approximate multiplication of two fuzzy numbers *A* and *B* are given in Eqs. (5.19) and (5.20).

$$A + B = [\, a_1 + b_1, a_2 + b_2, a_3 + b_3, a_4 + b_4 \,] \tag{5.19}$$

$$\begin{aligned} A \bullet B = [\, &\min(a_1 \bullet b_1, a_1 \bullet b_4, a_4 \bullet b_1, a_4 \bullet b_4), \\ &\min(a_2 \bullet b_2, a_2 \bullet b_3, a_3 \bullet b_2, a_3 \bullet b_3), \\ &\max(a_2 \bullet b_2, a_2 \bullet b_3, a_3 \bullet b_2, a_3 \bullet b_3), \\ &\max(a_1 \bullet b_1, a_1 \bullet b_4, a_4 \bullet b_1, a_4 \bullet b_4) \,] \end{aligned} \tag{5.20}$$

With a fuzzy representation of the variables in Eq. (5.15), IC is represented by a membership function μ_{IC}:

$$\mu_{IC}(\lambda, P, r, c_W), \quad \mu_{IC} \in [0,1] \tag{5.21}$$

This membership is determined by the convolution of the membership functions for the input variables. If trapezoidal fuzzy numbers are used, the membership function for IC can also be approximated by a trapezoid according to the assumption above, with corners C_1, C_2, C_3, C_4.

The expectation value of IC, or crisp value of IC, can be derived from the membership function by using a defuzzification method. Different methods for this are described in [72], where the Centre of Gravity (COG) is regarded as giving the most accurate result. In this method all elements in the space of possible outcomes are weighted with their membership values. With trapezoidal functions, operating on the 4 corners, the crisp value is found by the smallest and largest elements having membership equal to one. This is called the Mean of Max, which gives practically the same results as COG for regular functions.

The crisp value of IC or the expected annual cost is thus given by Eq. (5.22) using the corners for IC:

$$EIC = \frac{C_2 + C_3}{2} \tag{5.22}$$

The time variation and eventual time dependent correlation will be handled in the same way as for the analytical expectation method, i.e. expected (constant, crisp) time profiles are used. A practical procedure including the duration for each interruption is described in Section 6.4.

6 Models and methods for estimation of annual interruption costs in radial and meshed systems

The chapter describes the models and methods developed in this work. An analytical model is described for the estimation of expectation values for annual reliability indices with focus on annual interruption costs. Practical methods are developed for both radial and meshed systems, taking into account time variation and time dependent correlation. A Monte Carlo simulation model is developed which handles time variation and the additional stochastic variations. Practical calculation procedures are described for both radial and meshed systems. Furthermore a procedure for handling of uncertainties by a fuzzy description of variables is given in relation to the analytical method for radial systems.

6.1 Assumptions, simplifications and data

The formulation of annual interruption costs (IC) in Chapter 5 is the basis for the development of methods for the estimation of IC. The basic assumptions and simplifications used in these methods are given below. They are partly discussed in the following chapters.

- The models are developed for planning purposes (system planning, planning of operation and maintenance). As they stand they are not suitable for other purposes such as short term operation planning or in the operating phase.

- The models are developed for the estimation of annual interruption costs due to unexpected incidents and not particularly planned interruptions.

- Reliability and cost assessment is based on the types of components involved in a specific system solution, and the annual costs are estimated for this system solution.

- The average annual failure rate is assumed constant for the system solution and period considered, which represents the normal operating phase of a given system. This means that the failure rate is only influenced by stochastic variation and time variation in the failures of components and not by ageing (leading to increased failure rates).

- The time variation is separated in three *independent* average time profiles according to the data usually available. Hourly load curves may be available, on an annual basis with 8760 values. However, for the other variables, the data basis is more limited.

- Reasonable estimates of customers' interruption costs are assumed, and specific costs for energy not supplied are used in the models. The problems with the dispersions in the available cost estimates and the use of specific costs are discussed elsewhere.

- The general delivery point is considered a "black box" with a load P and a specific cost c_{W}, but a generalization for different types of customers or loads is given in Section 6.5.

- The variables determining the annual interruption costs are assumed independent except for the time dependency between them. The specific cost is however represented as a function of interruption time.

- For simplicity the calculation of energy not supplied (ENS) is made by multiplication of interrupted load and duration at the time of interruptions. In other words, the calculation does not follow the more accurate procedure in Eq. (3.6).

Data base required

The data required for the different methods can be grouped according to outage events and delivery points:

Outage events and system:

- failure rates and repair times
- sectioning times for the system (particularly radial systems)
- relative time profiles for failures, repair- and sectioning times
- System Available Capacity (SAC).

Delivery points:

- loads: P_{max}, P_{av} or utilization time
- Local Generation (LG)
- types of customers and their CDFs
- relative time profiles for the types of loads
- relative time profiles for the CDFs.

In addition, appropriate probability distributions for the input variables are required for the Monte Carlo simulation method.

6.2 Expectation method taking into account time dependency

6.2.1 Basic description

The basic description is based on the radial model (Chapters 3 and 5). Practical methods are however described for both radial and meshed systems in the following sections.

A formula for the expectation value EIC which includes the time dependency is given in Eq. (5.15). The assessment of the expectation in Eq. (5.15) implies estimation of the covariance. This is described in general in Appendix 2 for the product of two stochastic variables. It is shown that the expectation of the product can be estimated by multiplying the pairwise observations at points t_1, t_2, ..., t_n, and taking the average of these sub-products, Eq. (A2.8). This result is applied to deduce the expectation method. The expectation method for radial systems is described in more detail in Appendix 3.

The expectation in Eqs. (5.14) and (5.15) can be estimated by:

$$\begin{aligned} E(\lambda P r\, c_W(r)) &= \frac{1}{n}\sum_{i=1}^{n}\Big(\sum_{j=1}^{N_i} P(t_j) r(t_j) c_W(r(t_j))\Big)_i \\ &= \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} \lambda_{h,d,m} P_{h,d,m} r_{h,d,m} c_{W\,h,d,m}(r_{h,d,m}) \end{aligned} \tag{6.1}$$

where:

n	=	Number of years considered
N_i	=	Number of interruptions in year no ‘i’
t_j	=	Time of interruption no ‘j’ = $(h, d, m)_j$
$P(t_j)$	=	Expected load when the interruption occurs at $t_j = P_{h,d,m}$
$r(t_j)$	=	Expected duration when the interruption occurs at $t_j = r_{h,d,m}$
$c_W(r(t_j))$	=	Expected specific interruption cost when the interruption occurs at t_j, with duration $r(t_j)$, = $c_{w\,h,d,m}(r_{h,d,m})$
$\lambda_{h,d,m}$	=	Expected number of failures in time period (h, d, m).

In Eq. (6.1) ENS is determined by the product of $P(t_j)$ and $r(t_j)$. Since this implies an approximation to the more accurate calculation of ENS in Eq. (3.6), $P(t_j)$ should be interpreted as the expected load in the time period $r(t_j)$, when the interruption occurs at t_j. The load is in principle a function of the duration.

The expected costs in Eq. (6.1) represent the annual costs in the long run for a particular load stage. $P(t_j)$, $r(t_j)$ and $c_W(r(t_j))$ are pairwise observations at the time of interruptions t_j. The expectation values $P(t_j)$, $r(t_j)$ and $c_W(r(t_j))$ are determined from Eqs. (5.8), (5.7) and (5.10) respectively.

The number of years 'n' and the number of interruptions 'N_i' are replaced by the average number of failures at t_j, from Eq. (5.5). This means that the number of interruptions are determined by simulation of failures on different components and outage events. Eq. (6.1) is valid for one component or outage event and when the total load is interrupted. The formulation is modified in the practical methods described in the following sections.

6.2.2 Correction factors for radial models

In the model for radial systems, the time dependent expectations in Eq. (6.1) are replaced by the relative profiles and reference figures from Eqs. (5.5), (5.7), (5.8) and (5.10):

$$\begin{aligned} EIC &= \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} \lambda_{h,d,m} P_{h,d,m} r_{h,d,m} c_{W\,h,d,m}(r_{h,d,m}) \\ &= \lambda_{av} P_{\max} r_{av} c_{Wref}(r_{av}) \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h} q_{\lambda d} q_{\lambda m} k_{ph} k_{pd} k_{pm} k_{rh} k_{rd} k_{rm} k_{ch} k_{cd} k_{cm} \\ &= \lambda_{av} P_{\max} r_{av} c_{Wref}(r_{av}) k_{\lambda Prc} \end{aligned} \tag{6.2}$$

The summation of the products of the relative factors describing the time variation is replaced by a factor $k_{\lambda Prc}$. This factor is a correction factor which includes the time dependent correlation. The factor is referred to the maximum load P_{max} in accordance with Eq. (5.8). A description of correction factors is given below. Such factors can be applied to radial systems only, since they are based on a total interruption of load for each failure. An analytical method for meshed systems is described in Section 6.2.4.

An approximation is introduced in Eq. (6.2). It can be noticed that the specific cost is not represented as a function of $r_{h,d,m}$ in the last part of the formula. The time dependent specific cost is represented as a function of the average interruption time caused by the component and not as a function of the time dependent duration. This assumption is introduced to make it possible to *precalculate* correction factors for radial systems without having to represent all the data involved in the relative factors in the applications of the method. The assumption has no significant influence if the cost function is quite linear. This is further discussed in Chapter 7.

The magnitude of the time dependency in the variables can be expressed by the covariance. The covariance is given by the difference between the expected product in Eq. (5.14) and the product of the expectations in Eq. (5.12), see Appendix 2, Eq. (A2.1):

$$Cov(\lambda,P,r,c) = E(\lambda Prc) - \lambda_{av} P_{av} r_{av} c_{Wav}$$
$$= \lambda_{av} P_{av} r_{av} c_{Wav} \left(\frac{P_{\max}}{P_{av}} \frac{c_{Wref}}{c_{Wav}} k_{\lambda Prc} - 1 \right) \tag{6.3}$$

The second term in Eq. (6.3) is the product of expectation (‘av’ = average) values. The covariance will be denominated as annual costs, for instance in NOK per year.

Correction factors like $k_{\lambda Prc}$ in Eq. (6.2) contain the time dependency among the variables and are calculated on the basis of *expected* time profiles. The idea is to precalculate such factors for a certain area or, in more detail, for different types of components and types of loads in a particular system. The expected time profiles used are all relative profiles, referred to some chosen reference values. The choice of the references depends on the typical figures and data that are available. The reference figures used here are:

λ_{av} = the average annual number of failures
r_{av} = the annual average repair- or restoration time
P_{max} = the annual maximum (peak) load
c_{Wref} = the customer specific cost at the reference time.

Since the expected time profiles for daily, weekly and monthly variations are assumed to be independent, correction factors for each type of variation can be calculated separately, giving the total annual correction factor as the product of the day-, week- and month-factors.

Appendix 3 describes how these factors are calculated, and total correction factors are given for both U, EPNS, EENS and EIC:

Correction factor for the assessment of annual expected interruption time U:

$$k_{\lambda r} = k_{\lambda rh} k_{\lambda rd} k_{\lambda rm} \tag{6.4}$$

Correction factor for the assessment of annual expected power not supplied EPNS:

$$k_{\lambda P} = k_{\lambda Ph} k_{\lambda Pd} k_{\lambda Pm} \tag{6.5}$$

Correction factor for the assessment of annual expected energy not supplied EENS:

$$k_{\lambda Pr} = k_{\lambda Prh} k_{\lambda Prd} k_{\lambda Prm} \tag{6.6}$$

Correction factors for the assessment of annual expected interruption costs EIC:

$$k_{\lambda Pc} = k_{\lambda Pch} k_{\lambda Pcd} k_{\lambda Pcm}$$
$$k_{\lambda Prc} = k_{\lambda Prch} k_{\lambda Prcd} k_{\lambda Prcm} \qquad (6.7)$$

There are two factors in Eq. (6.7) for the assessment of EIC. The first one is a factor for annual costs of short interruptions, while the second is for long interruptions. A possible way of discriminating between costs for short and long interruptions is outlined in Appendix 3.

The total annual correction factors in Eqs. (6.4) - (6.7) will be less than, equal to or greater than 1.0, depending on the choice of reference figures. An example of the correction factor $k_{\lambda Prc}$ is given in Appendix 3 for a commercial load. With the reference figures above, $k_{\lambda Prc}$ is calculated to 0.66. More examples are given in Chapter 7.

On basis of Eqs. (6.6) and (6.7) a factor ‘b’ can be established:

$$b = \frac{k_{\lambda Prc}}{k_{\lambda Pr}} \qquad (6.8)$$

This factor is a correction factor for the specific cost, providing an *annual average specific cost,* including the additional time dependent correlation between this cost and the other variables.

6.2.3 Practical calculation method for radial systems

By the deduction of correction factors, an expectation method is provided, which includes the time dependent correlation between variables. As the formulas in the previous sections show, the correction factors can be used in conjunction with the simple expectation method presented in Chapter 3 and in Eq. (5.12).

The formula in Eq. (6.2) is primarily a general formulation according to a radial model, considering only one component. In this section a practical approach is presented. It is described in more detail in Appendix 3.

An alternative to the direct approach presented in the previous sections is to calculate energy (or power-) not supplied first and secondly the annual interruption costs. The calculation method is based on *simulation of failures* on the components in the supply network, using the analytical model RELRAD, described in Appendix 1.

General procedure

Determination of annual expected interruption costs for a particular delivery point:

1) Simulate failures in the components in the supply network to determine which components contribute to interruptions (λ, r) in the delivery point.

2) For each component ‘j’, calculate the contribution to annual expected energy not supplied and expected costs:

$$
\begin{aligned}
&1)\ EENS_j = \lambda_j P_{\max} r_j k^*_{\lambda Pr_j} \\
&\approx \lambda_j P_{\max} r_j k_{\lambda Pr} \\
&2)\ EIC_j = EENS_j c_{Wref}(r_j) b^*_j \\
&= \lambda_j P_{\max} r_j c_{Wref}(r_j) k^*_{\lambda Pr_j} b^*_j \\
&= \lambda_j P_{\max} c_{Pref}(r_j) k^*_{\lambda Prc_j} \\
&\approx \lambda_j P_{\max} k_{\lambda Prc} c_{Pref}(r_j)
\end{aligned}
\tag{6.9}
$$

where:

$EENS_j$ = contribution to expected energy not supplied from component no. ‘j’
EIC_j = contribution to annual costs from component ‘j’
λ_j = average failure rate for component ‘j’
r_j = average duration in the delivery point caused by component ‘j’
$c_{Wref}(r_j)$ = specific cost for duration r_j , reference value (= $c_{Pref}(r_j)/r_j$)
b^*_j = resulting correction factor, including time dependent correlation between $EENS_j$ and specific interruption cost for the delivery point
$k^*_{\lambda Prj}$ = correction factor for component ‘j’, calculated from Eqs. (6.6) and (A3.47)
$k^*_{\lambda Prcj}$ = correction factor for component ‘j’ and the delivery point, calculated from Eqs. (6.7) and (A3.44).

b^*_j for each component is determined using Eq. (6.8) with the component specific k-factors.

3) Sum up the contributions from each component to determine the annual figures EENS and EIC:

$$
\begin{aligned}
EENS &= \sum_{j=1}^{J} \lambda_j P_{\max} r_j k^*_{\lambda Pr_j} \\
&= P_{\max} \sum_{j=1}^{J} \lambda_j r_j k^*_{\lambda Pr_j} \\
&\approx P_{\max} k_{\lambda Pr} \sum_{j=1}^{J} \lambda_j r_j
\end{aligned}
\tag{6.10}
$$

$$
\begin{aligned}
EIC &= \sum_{j=1}^{J} EENS_j \; c_{Wref}(r_j) b^*_j \\
&\approx P_{\max} k_{\lambda Prc} \sum_{j=1}^{J} \lambda_j c_{Pref}(r_j)
\end{aligned}
\tag{6.11}
$$

where J is the total number of components.

In Eqs. (6.10) and (6.11) the specific interruption cost is represented in two different ways: $c_{Wref}(r_j)$ is given in costs per kWh and $c_{Pref}(r_j)$ in costs per kW. The last representation is often referred to as a Customer Damage Function (CDF), see Chapter 2.

Notice that in Eq. (6.9) correction factors per component are introduced. In this way it is possible to use separate precalculated correction factors for different components. The general correction factors for the area include all types of failures and not only the types of components and failures included in the system solution under study. Using the general factors will thus give less accurate results. Whether it is possible to precalculate factors for different components, depends on the data available. Using individual correction factors permits the use of different time profiles for different components.

A flow chart for the calculation procedure is given in Fig. 6.1.

If we are able to precalculate correction factors for a certain area, this expectation method gives a simple analytical approach to calculate the annual expected costs, while considering the time dependent correlation between variables. By referring the factors to some known (or easily derived) reference values, the formulas presented here and in Appendix 3, give a practical approach to the assessment of annual expectations of reliability indices for delivery points in radial systems. The main results from this method are expectation values of the reliability indices and correction factors including the time dependent correlation. The method can be used to study the influence of the time variation.

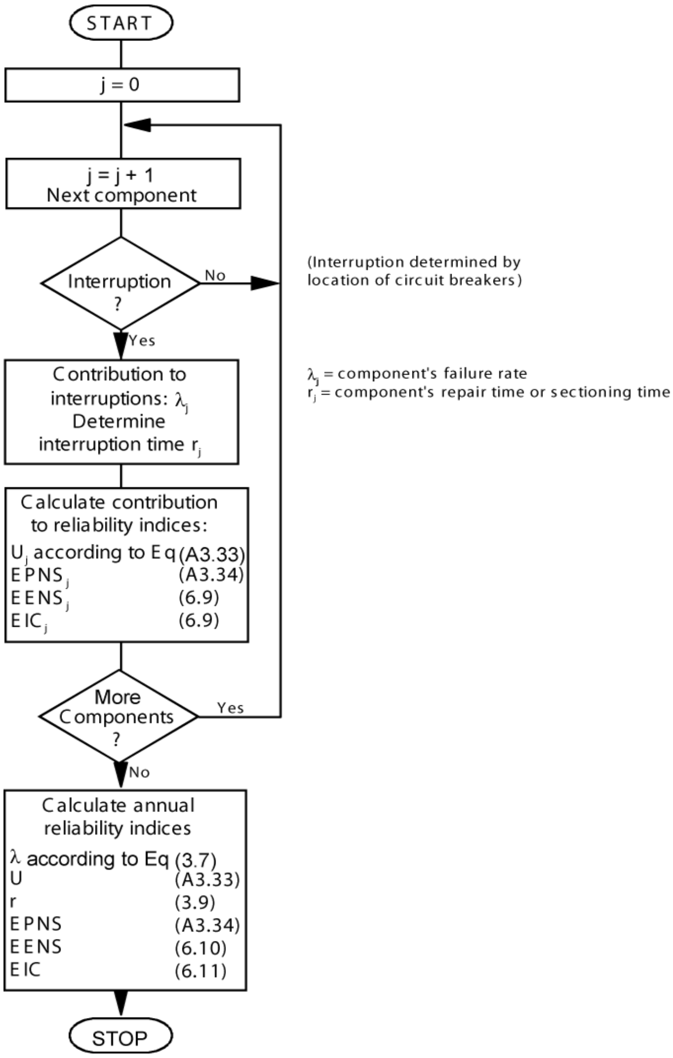


Fig. 6.1 Flow chart: Algorithm for analytical assessment of annual interruption costs for delivery points in radial systems.

6.2.4 Practical calculation method for meshed systems

As mentioned in Section 6.2.2, the correction factors cannot be applied directly to meshed systems. The estimate of EIC in Eq. (6.1) is now determined using the probabilities of failures at particular times (h, d, m) given by Eqs. (5.4) and (5.6). The method is based on a list of the predetermined minimum cuts or outage events giving interruptions to the delivery point. For each time period it should be checked if an interruption occurs according to Eq. (3.1) and if so, the amount of load to be disconnected according to Eq. (3.4).

In this procedure different time profiles for failures and repair time can be applied for the different outage events. The System Available Capacity (SAC) corresponding to each outage event j as well as the Local Generation (LG) in the delivery point can in principle be represented by a time variation.

For each outage event ‘j’ the following procedure can be followed:

1) Determine the time of occurrence (Loop through the months (m = 1, .., 12), weekdays (d = 1, .., 7) and hours (h = 1, .., 24))

2) Determine the number of failures in hour h, on weekday d and in month m:

$$\lambda_{j\,h,d,m} = \lambda_j \, q_{\lambda jh} \, q_{\lambda jd} \, q_{\lambda jm} \tag{6.12}$$

where λ_j is the equivalent failure rate for the outage event.

3) Determine the expected load $P_{h,d,m}$ from Eq. (5.8)

4) Does an interruption occur: $P_{h,d,m} > SAC_{h,d,m} + LG_{h,d,m}$? (Eq. (3.1))

5) If so, determine the power interrupted: $\Delta P_{h,d,m} = P_{h,d,m} - SAC_{h,d,m} - LG_{h,d,m}$ (Eq. (3.4))

6) Determine expected duration $r_{j\ h,d,m}$ of the interruption from Eq. (5.7), using the equivalent repair time r_j for the outage event.

7) Determine expected interruption cost $c_{h,d,m}(r_{h,d,m})$ from Eq. (5.10) and the CDF

8) Calculate the contribution to the reliability indices from time period (h, d, m):

$$\begin{aligned}
(\Delta\lambda)_j &= \lambda_{j\,h,d,m} \\
(\Delta U)_j &= \lambda_{j\,h,d,m} \, r_{j\,h,d,m} \\
\Delta EPNS_j &= \lambda_{j\,h,d,m} \, \Delta P_{h,d,m} \\
\Delta EENS_j &= \lambda_{j\,h,d,m} \, r_{j\,h,d,m} \, \Delta P_{h,d,m} \\
\Delta EIC_j &= \Delta EPNS_j \, c_{h,d,m}(r_{j\,h,d,m})
\end{aligned} \tag{6.13}$$

9) If no interruption occurs at (h, d, m), go to step 1)

10) Calculate the contributions to the annual indices for the delivery point, from outage event ‘j’ by summation of the contributions from each time period, 2016 all together (only EIC_j is shown) :

$$EIC_j = \sum_{h=1}^{24} \sum_{d=1}^{7} \sum_{m=1}^{12} \Delta EIC_{j\,h,d,m} \tag{6.14}$$

11) Sum up the contributions from all outage events:

$$EIC = \sum_{j=1}^{J} EIC_j \tag{6.15}$$

where J is the total number of outage events affecting the delivery point.

Notice that the time dependency between interruption cost and duration is represented in this method (step 8). A flow chart for this algorithm is given in Fig. 6.2.

The main results from this method are expectation values for the reliability indices. Time variation in the indices can be provided. This method can be used to study the influence of the time variation.

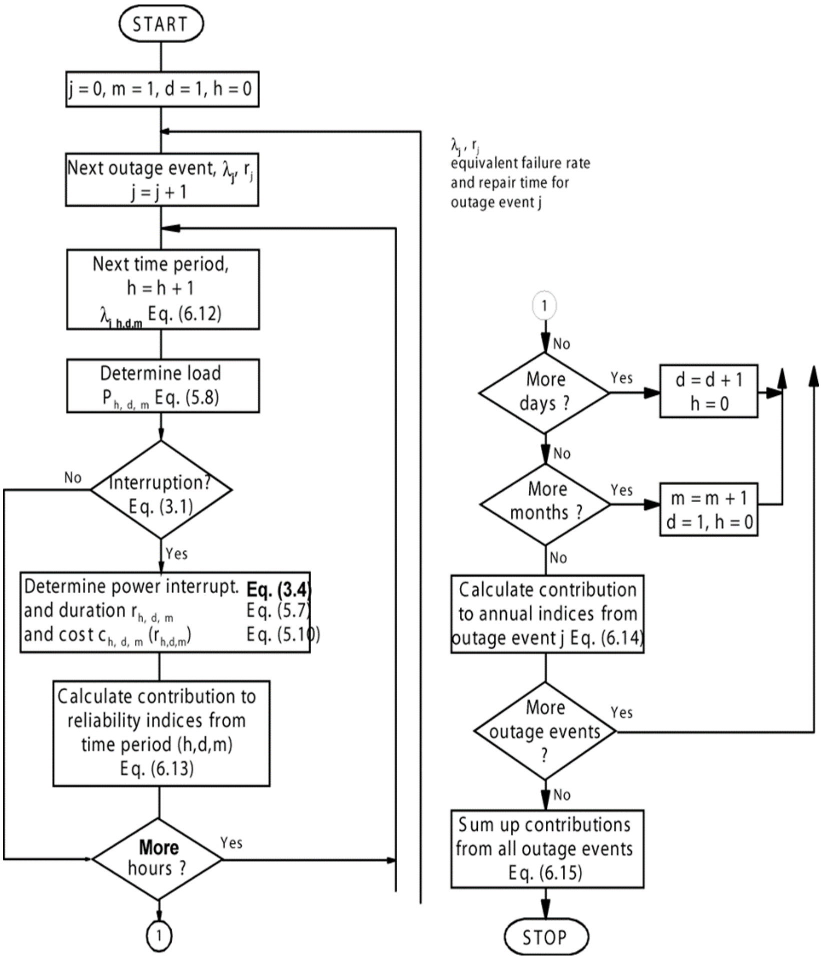


Fig. 6.2 Flow chart: Algorithm for analytical assessment of annual interruption costs for delivery points in meshed systems.

6.3 Monte Carlo simulation method

The analytical models that account for time dependent correlation, described in Section 6.2, allow us to assess the annual expected power- and energy not supplied (EPNS and EENS) as well as the annual expected costs (EIC). The time profiles used to handle the time variation represent average cyclic behaviour of failure rate, repair time, load and specific cost. The stochastic variation can be handled by Monte Carlo simulation as described in Chapter 5.

Classical Monte Carlo methods [13] determine the time of occurrence of failures by sampling the time to next event from the exponential distribution by a constant parameter λ. A time-varying failure rate is represented in the classical methods by prediction of weather and the use of different failure rates and repair times for different weather states. Sequential simulation is used to represent the chronological annual load profile and determine the interruption time [51 - 53].

The Monte Carlo simulation method developed in this work is based on the same list of predetermined outage events as the analytical method for meshed systems. The principles of the method are shown in Fig. 6.3 and explained in the following.

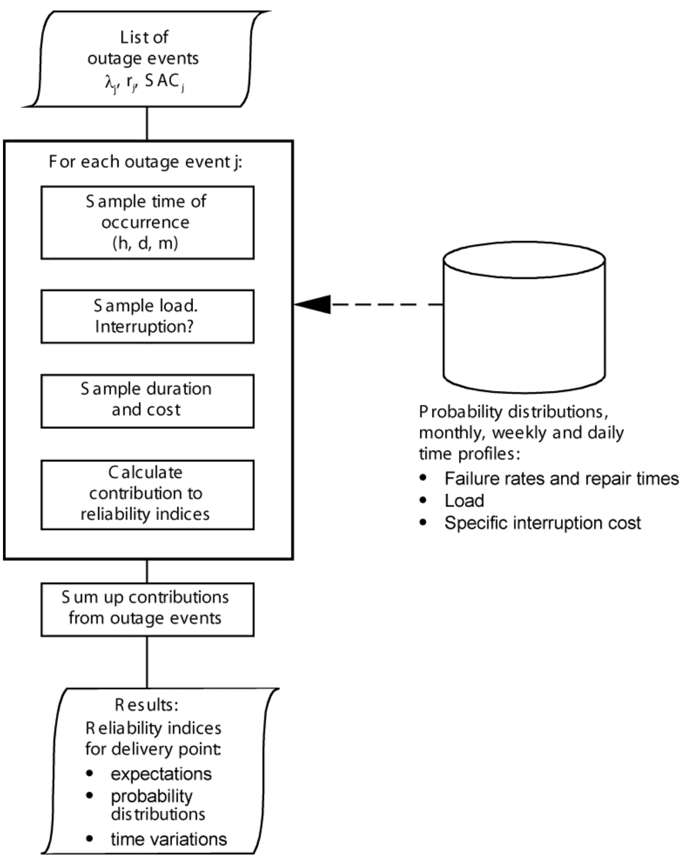


Fig. 6.3 Monte Carlo simulation model for assessment of annual interruption costs for delivery points in radial and meshed systems.

6.3.1 Random drawing of failures from time profiles

The same basic information that was used to represent the time-varying failure rate in the analytical expectation method is now used to time tag an interruption and find the time dependent average values of the load, interruption duration and interruption cost. Section 5.2 provides the conditional probabilities of having failures in hour ‘h’, on weekday ‘d’ and month ‘m’ respectively:

$$q_{\lambda h} = \frac{\lambda_h}{\lambda_{av}}$$
$$q_{\lambda d} = \frac{\lambda_d}{\lambda_{av}} \qquad (6.16)$$
$$q_{\lambda m} = \frac{\lambda_m}{\lambda_{av}}$$

The number of failures per year is determined by random drawing from the Poisson distribution. The timing of these failures is given by the probabilities in Eq. (6.16). Hour, weekday and month are drawn independently and randomly for each failure from discrete probability distributions formed by the above probabilities. An example of a probability distribution for failures in different months is shown in Figure 6.4. The cumulative probability distribution is established by accumulating the probability for month 1 (January), month 1 and 2 (February) and so on.

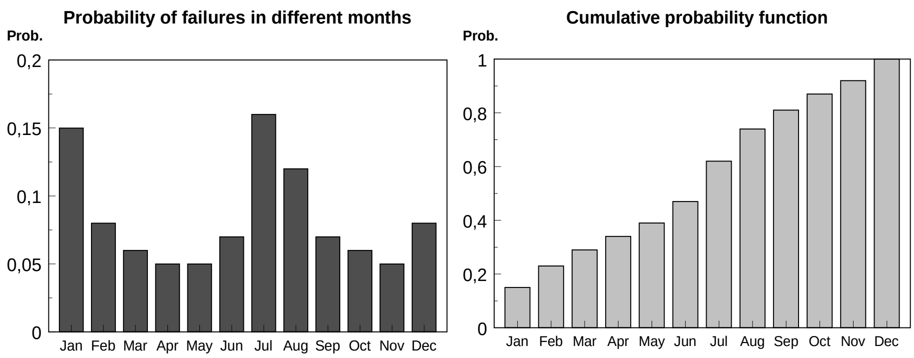


Fig. 6.4 Probability of occurrence of failures in different months.

Once the time of occurrence of each failure is determined, it should be checked if an interruption occurs according to Eq. (3.1). The expected load, duration and specific cost for the particular interruption are given by Eqs. (5.8), (5.7) and (5.10) respectively.

The annual chronology of failures and load is not represented in this method, but by time-tagging the interruptions, the time dependent load, duration and specific cost are found from the relative profiles.

6.3.2 Stochastic variations

The stochastic variation "vertical" to the time-varying average values are represented for each variable as shown in Chapter 4 and described in Chapter 5. Fig. 4.1 illustrates that the dispersion in a variable can vary in different time periods. This varying dispersion is represented by defining a probability distribution for each time interval, cfr. Fig. 5.6. The same type or class of distributions is assumed for all time periods, but the parameters may vary from time to time, if a parametric distribution is chosen.

When the time of occurrence of interruptions and the expectation values are determined as described in the previous section, the actual values of the variables are found by random drawing from the appropriate probability distribution valid for the actual time $t_j = (h, d, m)_j$ for interruption no.'j'. The expectation value at t_j is used to determine the parameters in the probability distribution. An example for the load P is given in the following.

Let us assume that an interruption occurs in January on a Tuesday at 1 p.m. The expected load at this time is 100 kW. The load is assumed to be Normal distributed with a standard deviation σ_P = 10 %. The expectation value of 100 kW is now the parameter μ_P in the distribution. An illustration of the Normal distribution is given in Fig. 6.5.

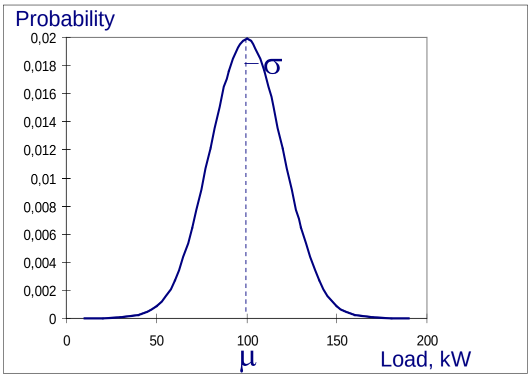


Fig. 6.5 Example of Normal distribution for the load P

As a base case it is chosen to represent the stochastic variations for failures, repair time, load and specific interruption cost as described in Chapter 4:

λ - Poisson distributed with parameter λ_{av}
r - Exponentially distributed with parameter $1/r_{h,d,m}$
P - Normal distributed with parameters $\mu_P = P_{h,d,m}$ and σ_P in % of $P_{h,d,m}$
c_W - Normal distributed with parameters $\mu_c = c_{h,d,m}(r_{h,d,m})$ and σ_c in % of $c_{h,d,m}$.

The stochastic variation in the number of failures from year to year is represented by the Poisson distribution. The stochastic variation is otherwise inherent in the simulation process, since t_j is drawn randomly from the probability distributions formed by Eq. (6.16). In this way it is possible to consider the variations in λ from year to year independently from the variations within a year, which means that these two aspects can be decoupled in the simulation.

6.3.3 Simulation procedure

The Monte Carlo approach which is developed in this study includes the following steps. These steps are performed per component 'j' or per outage event 'j' (minimum cut). Each event is studied separately to determine the contribution to the estimate in Eqs. (5.15) and (6.1) as well as the probability distribution.

The simulation procedure can be applied for both radial and meshed systems. The outage events can be represented by separate time profiles for failures and repair time. SAC corresponding to each event as well as LG in the delivery point may in principle be represented as stochastic variables with a time variation.

1) Determine the number of failures (interruptions) N_i supposed to occur next year (in year i). Poisson distribution is assumed.

2) For each failure k determine in which *hour (h)*, *weekday (d)* and *month (m)* it occurs, by sampling from the conditional probability distributions given by Eq. (6.16).

3) Determine the expected load $P_{h,d,m} = \mu_P$ using Eq. (5.8). The actual load P_k is found by sampling from the Normal distribution with μ_P and σ_P as parameters. σ_P is defined relative to μ_P.

4) Does an interruption occur: $P_k > SAC_k + LG_k$? (Eq. (3.1))

5) If so, determine the power interrupted: $\Delta P_k = P_k - SAC_k - LG_k$ (Eq. (3.4))

6) Determine the expected duration $r_{h,d,m}$ of the interruption using Eq. (5.7). To find the actual duration r_k, an appropriate probability distribution has to be specified, for example the exponential, lognormal- or Weibull function.

7) Determine expected specific interruption cost $c_{h,d,m}$ using the actual Customer Damage Function (CDF) with r_k from step 6) and Eq. (5.10). A probability distribution for the cost has to be specified to find the actual cost $c(r_k)$.

8) Determine the reliability indices for interruption k (shown for ENS and IC):

$$\begin{aligned} ENS_k &= \Delta P_k \, r_k \\ IC_k &= \Delta P_k \, c(r_k) \end{aligned} \tag{6.17}$$

The cost function in NOK/kW is used for the specific cost $c(r_k)$

9) Repeat steps 2) - 8) for each failure in the year and for a specified number of years n.

10) Calculate annual expectation values for the reliability indices according to Eqs. (6.20 - 6.25) below.

11) Sum up the contributions from all outage events:

$$EIC = \sum_{j=1}^{J} EIC_j \tag{6.18}$$

The drawings of h, d and m are made using a random generator and the Inverse Transform Method [13]. If X is a random variable and F(X) the corresponding discrete probability distribution, X is determined by

$$X = F^{-1}(U) = min\{x: F(X) \geq U\} \quad (0 \leq U \leq 1) \tag{6.19}$$

The contribution from component 'j' or outage event 'j' to the annual reliability indices for the delivery point are calculated from the following formulas. K is the total number of simulations (or failures).

Annual number of interruptions:

$$\lambda_j = \frac{1}{n}\sum_{k=1}^{K} y \quad [interrupt./year] \tag{6.20}$$

where y = 1 if P > SAC + LG and 0 otherwise.

Annual interruption time:

$$U_j = \frac{\sum_{k=1}^{K} r_{jk}}{n} \quad [hours/year] \tag{6.21}$$

where $r_{jk} = 0$ when no interruption occurs.

Average interruption time (Eq. (3.9)):

$$r_j = \frac{U_j}{\lambda_j} \quad [hours/interrupt.] \tag{6.22}$$

Annual expected power not supplied:

$$EPNS_j = \frac{\sum_{k=1}^{K} \Delta P_{jk}}{n} \quad [kW/year] \tag{6.23}$$

where $\Delta P_{jk} = 0$ when no interruption occurs.

Annual expected energy not supplied:

$$EENS_j = \frac{\sum_{k=1}^{K} ENS_{jk}}{n} = \frac{\sum_{k=1}^{K} \Delta P_{jk}\, r_{jk}}{n} \quad [kWh/year] \tag{6.24}$$

where $ENS_{jk} = 0$ when no interruption occurs.

Annual expected interruption costs:

$$EIC_j = \frac{\sum_{k=1}^{K} IC_{jk}}{n} = \frac{\sum_{k=1}^{K} \Delta P_{jk}\, c(r_{jk})}{n} \quad [NOK/year] \tag{6.25}$$

where $IC_{jk} = 0$ when no interruption occurs.

A prototype of this simulation procedure is developed in Microsoft Excel 5.0, which is used to provide the illustrations in Chapters 7 and 8. The prototype is developed to handle the ideas of representing both the time variation and stochastic variations and provide a flexible model which is independent of the types of probability distributions chosen for different variables. No particular effort has been made to reduce the computation or simulation time by for instance applying certain techniques for this. As shown in Chapters 7 and 8, the prototype is suitable for illustration of the principles both for some simple examples and more realistic cases from the transmission and distribution system.

In the prototype the simulations of failures are performed independently from the stochastic variations from year to year. The number of simulations necessary to reach a certain level of accuracy will depend on the equivalent failure rate for the outage event (amongst others). The number of years will therefore vary from outage event to outage event, and is determined in the following way:

$$n = \frac{K}{\lambda_j} \tag{6.26}$$

where K is the total number of failures simulated and λ_j is the equivalent failure rate for outage event ‘j’.

The method is applicable to both radial and meshed systems. The main results from this method are expectation values and probability distributions for the reliability indices. Time variation in the indices can be provided. The probability distributions can be used to investigate the probabilities of getting values lower or higher than certain figures, for instance according to reliability constraints. For particular customers or delivery points this kind of information may be of high importance. Other possible applications of the method are to study the impact on the annual indices of various aspects, such as:

- the combined effect of time variation and stochastic variation
- different probability distributions
- nonlinearity in the cost function

6.4 Fuzzy description of uncertainties

A procedure using a fuzzy description of uncertainties is developed in conjunction with the radial model described in Section 6.2.3. It is possible to adjust the procedure for the model for meshed systems described in Section 6.2.4. However, this is not carried through in this work.

6.4.1 Fuzzification of variables

Trapezoidal membership functions are chosen for all the variables to illustrate the procedure. It is chosen to determine the corners by relative deviations (in %) from the crisp expectation values.

The time variation is represented by the average time profiles as for the methods described in the previous sections. The correction factors are therefore considered as constants that can be multiplied with the fuzzy variables to achieve the reliability indices.

At first the annual failure rate is taken as a constant, i.e. a crisp failure rate is considered. The procedure for radial systems in Section 6.2.3 is extended by a fuzzification of the input variables:

For each component ‘j’:

2a) Fuzzify the repair time, load and specific interruption cost by applying trapezoidal membership functions:

$r = [r_1, r_2, r_3, r_4]$
$P = [p_1, p_2, p_3, p_4]$
$c_W = [c_1, c_2, c_3, c_4]$.

The corners are determined by relative deviation from the expectations or reference figures: r_{av}, P_{max} and c_{Wref}.

It is assumed that the uncertainty in r, P and c are time independent and that the time variation is handled using the crisp correction factors. The uncertainty in the specific cost is assumed to be independent of the duration r. (Otherwise the fuzzy specific cost would be a function of the fuzzy duration.) The cost function in NOK/kW is used to determine annual costs as the product of failure rate, load and specific cost.

6.4.2 Fuzzy annual interruption costs

The contributions from each component 'j' to the annual reliability indices are calculated according to the procedure in Section 6.2.3, step 2) Eq. (6.9), applying the rules for multiplication of fuzzy numbers as described in Section 5.4.2.

In Eq. (6.9) for ENS_j there is a product of the fuzzy numbers P_{max} and r_j to be multiplied with the crisp λ_j and the crisp correction factor $k_{\lambda Pr}$. The contribution to the fuzzy annual interruption costs are similarly found by Eq. (6.9):

$$IC_j = \lambda_j P_{\max} c_{Pref}(r_j) k_{\lambda Prc} \qquad (6.27)$$

The annual costs are determined by the product of the fuzzy variables P_{max} and $c_{Pref}(r_j)$ for the crisp value of r_j, multiplied by the crisp variables λ_j and $k_{\lambda Prc}$.

In step 3) of the procedure in Section 6.2.3 the total indices are found by a summation of contributions. The rule for summation of fuzzy numbers described in Section 5.4.2 is applied, giving the corners of the membership functions:

$$IC = \sum_{j=1}^{J} IC_j = [C_1, C_2, C_3, C_4] \qquad (6.28)$$

The results of this procedure for radial systems are the corners of the membership functions for the annual reliability indices. The crisp indices can be found applying the defuzzification method described in Section 5.4.2:

$$EIC = \frac{C_2 + C_3}{2} \qquad (6.29)$$

When symmetrical trapezoidal functions are used, whose corners are defined by relative figures from the expectation values, the crisp values will turn out to be approximately equal to those found by the expectation method. This is shown by examples in Ch. 7.

If the failure rate also is fuzzified, both ENS and IC are determined by products of 3 fuzzy variables instead of 2. This leads to wider resulting membership functions and a shift of the corners compared to using a crisp failure rate. The examples in Section 7.4 show a larger inaccuracy in the crisp indices due to this. The case with a crisp failure rate is under the assumptions used here, comparable to results from both the expectation method and the Monte Carlo method, where the average failure rate is a constant.

The main results of this procedure are crisp (expectation) values and membership functions for the reliability indices. In analogy to the probability distributions, these functions can be used to investigate the possibilities of getting values lower or higher than certain figures. The procedure can be used to study the influence of different membership functions and the combined effect of time variation and uncertainties in input variables.

6.5 Generalization of the model for annual costs

The model for assessment of annual interruption costs for general delivery points presented in the previous sections, is based on the application of specific interruption costs referred to energy not supplied. The delivery point has been regarded as a “black box” with a single load and a single specific cost. This section provides a generalization of the model for annual costs to incorporate different customer groups and different loads. A model is also presented based on the absolute cost per interruption.

6.5.1 Application of specific vs. absolute cost

As was pointed out in Chapter 2, the respondents’ costs for different interruption scenarios, are normalized to provide general comparable costs for different customer categories. In practice the assessment of annual interruption costs have been attached to the reliability assessment as a natural extension. At least this is true for the assessment of long interruptions, where the quantity of energy not supplied is calculated and multiplied by a specific cost.

With a specific cost referred to ENS, the variations in c_W are determined by variations in both the load and the cost per interruption as is shown in Chapter 4 and Appendix 3. Other ways of normalizing the interruption costs per interruption scenario are to refer the cost to the annual energy consumption W or to the peak load P_{max}. In these alternative cases, the normalizing factor is a constant.

The three ways of normalizing the interruption cost are illustrated in the formulas below:

$$1) \quad c_{1,ref} = \frac{C_{ref}}{EENS_{ref}} \tag{6.30}$$

$$2) \quad c_{2,ref} = \frac{C_{ref}}{W} \tag{6.31}$$

where W is the annual energy consumption.

$$3) \quad c_{3,ref} = \frac{C_{ref}}{P_{\max}} \tag{6.32}$$

The representations in 2) and 3) make it possible to recalculate an estimate of the absolute cost C_{ref} by multiplying by W or P_{max}, or in representation 1) by $EENS_{ref}$. In that case it is not necessary to calculate the relative variation in specific cost (Eq. (4.2)). The cost model described in Ch. 5 will have to be modified and Eq. (5.10) replaced by:

$$C_{h,d,m} = \frac{C_h}{C_{ref}} \frac{C_d}{C_{ref}} \frac{C_m}{C_{ref}} C_{ref} \tag{6.33}$$

where the relative variation referred to the cost at reference time is assumed to be given from customer surveys. Examples of these relative variations are included in Ch. 4. Eq. (6.33) will now be used to calculate correction factors based on the absolute cost per interruption, see below.

6.5.2 Model with absolute cost per interruption

By using the absolute cost per interruption, the annual interruption costs can be found by estimation of the time of occurrence of interruptions and summing up the costs per incident. Using the second expression for the specific cost above, we get the following expression for the annual costs (shown for the radial model only):

$$\begin{aligned} EIC &= \sum_j \lambda_j c_{ref}(r_j) W \, k^*_{\lambda r C_j} \\ &= \sum_j \lambda_j C_{ref}(r_j) k^*_{\lambda r C_j} \end{aligned} \tag{6.34}$$

This equation replaces Eq. (6.11). Notice that Eq. (6.34) is independent of the load, and the correction factor $k^*_{\lambda rCj}$ includes the time dependent correlation between the reliability level and the absolute cost C. The cost variations are no longer dependent on the load variations.

6.5.3 Aggregation of customer costs

The total load in a delivery point will in the general case consist of different loads $\underline{x}$ composed of different customer groups $\underline{c}$, as outlined in Chapter 3. The specific interruption costs can be weighted together using a proper weight such as the proportion of the annual energy consumption or the maximum load in the delivery point. The resultant specific interruption cost is determined as follows:

$$c_{res} = \sum_{i=1}^{s} w_i c_i \tag{6.35}$$

where:

s = number of customer- or load groups connected to the delivery point
w_i = weight for customer- or load group no. i
c_i = specific cost for customer- or load group no. i.

The annual interruption costs can now be calculated using the methods described in this chapter.

For a radial model, the annual costs can be determined separately for each customer- or load group according to the procedures in Section 6.2, and the total costs be found by summing up the costs for each group. This will maintain the information on each group's contribution to the total annual costs. An alternative formulation to Eq. (6.11) for the aggregation of annual costs is then:

$$EIC = P_{\max} k_{\lambda Prc} \sum_{j=1}^{J} \lambda_j \Big(\sum_{i=1}^{s} c_{i,ref}\big(r_j \big) w_i \Big) \tag{6.36}$$

The variables are as before. It is assumed that the different loads and specific costs have the same relative variations, such that the correction factor $k_{\lambda Prc}$ is constant for each interruption.

If a selective disconnection of the load is possible in meshed systems, according to a classification in interruptible load, critical load etc., both the interruption time and the specific cost may be different for the different classes of loads. This yields a different formulation of the annual cost. A formulation for the contribution from outage event no. j and time period (h, d, m), is given below (cfr. Eq. (6.13)). The total load is divided in s load groups.

$$\Delta EIC_j = \lambda_{j\,h,d,m}(\Delta P_1 c_1(r_{1j}) + \Delta P_2 c_2(r_{2j}) + \ldots\ldots)_{h,d,m} \quad \sum_{i=1}^{s} r_{ij} = r_{j\,h,d,m}$$
$$= \lambda_{j\,h,d,m} \sum_{i=1}^{s} (\Delta P_i c_i(r_{ij}))_{h,d,m} \tag{6.37}$$

where:

ΔP_i = interrupted load for load group no. i (in time period (h, d, m))
r_{ij} = interruption time for load group no. i, from event no. j, (in time period (h, d, m))
c_i = specific interruption cost for load group no. i for duration r_{ij} (in time period (h, d, m)).

Eq. (6.37) replaces Eq. (6.13) in the analytical model. A similar formulation for the Monte Carlo model would be:

$$ENS_k = \Delta P_{1k} r_{1k} + \Delta P_{2k} r_{2k} + \ldots. = \sum_{i=1}^{s} \Delta P_{ik} r_{ik} \quad \sum_{i=1}^{s} r_{ik} = r_k$$
$$IC_k = \Delta P_{1k} c_1(r_{1k}) + \Delta P_{2k} c_2 r_{2k} + \ldots. = \sum_{i=1}^{s} \Delta P_{ik} c_i(r_{ik}) \tag{6.38}$$

Eq. (6.38) replaces Eq. (6.17) and gives the contribution to ENS and IC from failure k for outage event no. j.

7 Illustration of calculation methods: Case studies

This chapter gives some illustrations of the calculation methods in connection with a small base case example, based on example data from Chapter 4. The results are merely examples to illustrate the main features of the calculation methods. The influence of time variation is demonstrated, and a comparison is made with the traditional analytical method. The effect of different probability distributions and the handling of fuzziness is illustrated. Two small examples showing the use of the calculation methods for radial and meshed systems are included.

7.1 Base case

The calculation methods described in Chapter 6 can be demonstrated by the simple base case shown in Figure 7.1. This case consists of a single delivery point supplied by a distribution system. The network is represented by an equivalent component. A description of the case and the basic data is given in this section.

The base case results themselves will not be of particular interest, but the simple example is found suitable to illustrate the principles and show what kind of information the methods give.

7.1.1 Description of delivery point

The delivery point has a single customer connected. This is an industrial customer with an 8-hour shift a day and a maximum load of 100 kW. The average load on an annual basis is P_{av} = 43 kW, with a utilization time of about 3750 hours.

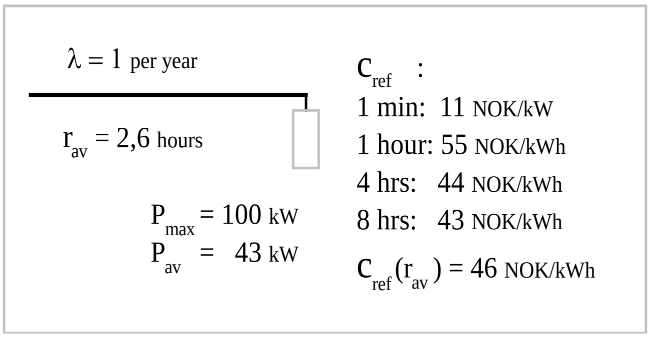


Fig. 7.1 Base case. Example: industrial load.

The specific interruption cost for the industrial load is given as discrete values in NOK referred to energy not supplied, at the reference time. The figures represent the average cost for industrial customers in 1995 values, based on the Norwegian survey conducted in 1991. A Customer Damage Function (CDF) for the delivery point is established by interpolation between the discrete points, giving a cost function in NOK/kW at the reference time. The CDF is shown in Fig. 7.2.

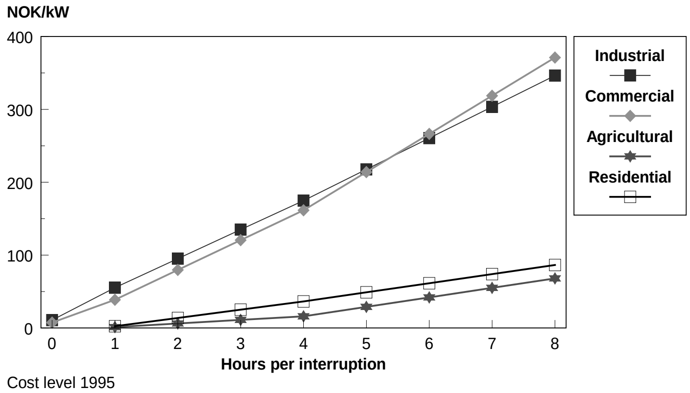


Fig. 7.2 Customer Damage Functions, at reference time.

The distribution system supplying the delivery point is replaced by a single component having one failure per year ($\lambda = 1$) on average, with an average repair time of 2.6 hours.

7.1.2 Basic data

The reference values are given in Figure 7.1. The basic time variations which will be used throughout this chapter are given in Tables 7.1 - 7.3. They are presented in Chapter 4, covering 6 years of failure statistics for distribution networks, typical load profiles and cost data from the Norwegian customer survey. The tables show the relative time variations in failures, repair time, load and specific interruption costs. The relative factors are rounded off in the tables (giving the sum of q_λ-factors somewhat greater than 1.0).

Table 7.1 Relative monthly variation in failures, repair time, load and specific interruption cost.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$q_{\lambda m}$	0.15	0.08	0.06	0.05	0.05	0.07	0.16	0.12	0.07	0.06	0.05	0.08
k_{rm}	1.49	1.46	0.92	0.78	0.73	0.78	0.72	0.73	0.77	0.85	0.87	1.19
P_m/P_{av}	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
c_m/c_{ref}	1.00	1.01	1.00	1.00	1.02	1.05	0.94	1.01	1.03	1.04	1.06	1.08

Table 7.2 Relative weekly variation in failures, repair time, load and specific interruption cost.

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
$q_{\lambda d}$	0.16	0.14	0.15	0.15	0.15	0.13	0.12
k_{rd}	0.89	0.88	1.14	0.90	0.97	1.21	1.02
P_d/P_{av}	1.17	1.17	1.17	1.17	1.17	0.58	0.58
c_d/c_{ref}	0.86	0.86	0.86	0.86	0.86	1.02	1.04

Table 7.3 Relative daily variation in failures, repair time, load and specific interruption cost.

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$q_{\lambda h}$	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.05	0.07	0.07	0.07	0.05	0.08	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.02	0.02
k_{rh}	1.73	1.37	1.51	1.21	0.99	0.81	0.87	0.71	0.63	0.82	0.84	0.75	0.68	0.81	0.96	1.38	1.25	1.10	1.17	1.34	1.07	1.41	1.58	1.95
P_h/P_{max}	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
c_h/c_{ref}	1.24	1.24	1.24	1.24	1.24	1.24	1.62	1.62	1.17	1.17	1.17	1.17	1.16	1.16	1.16	1.16	1.41	1.41	1.41	1.41	1.39	1.39	1.39	1.39

7.2 Expectation method

The expectation method for radial systems taking into account time variation is described in Section 6.2. This method enables the reliability indices for the delivery point to be calculated on the basis of reference values and correction factors, according to the radial model. The analytical method for meshed systems is applied to the example with parallel lines in Section 7.7 and the transmission case in Chapter 8.

Summary of results:

The results given in these sections illustrate that the time variation *may* be of importance for the reliability indices as a whole. Figs. 7.3 and 7.4 show that there is a strong pairwise correlation in particular time periods with correlation factors of about ± 0.6 - 0.9, but the resulting correlation is practically non-significant for the annual indices: In the base case example (industrial load) EPNS is increased by 9 % and EIC is reduced by 5 %, while EENS is unchanged compared to the tradtional method. This conclusion is based on new and updated data compared to the data used in a study reported in the paper included in Appendix 4. The paper was written in an early phase of this work. The calculation methods was demonstrated by the same simple example. However, the data data used in the paper led to a significant increase in the results for EENS and EIC taking the time variation into account (about 30 % and 20 % respectively).

Application of a *specific cost at reference time* leads to an underestimation of the annual costs by 14 % for the industrial load and 45 % for the commercial load.

7.2.1 Basic results

Correction factors are calculated with the data in Tables 7.1 - 7.3, using Eqs. (6.4 - 6.8) and (A3.21 - A3.23). The factors are given in Table 7.4:

Table 7.4 Correction factors for base case, industrial load.

$k_{\lambda r}$	$k_{\lambda P}$	$k_{\lambda Pr}$	$k_{\lambda Prc}$	$b = k_{\lambda Prc}/k_{\lambda Pr}$
0.976	0.468	0.432	0.493	1.141

The reliability indices are calculated from Eqs. (3.7), (3.9) and (A3.33 - A3.36) and given in Table 7.5.

Table 7.5 Reliability indices for the base case delivery point.

Reliability index	Expectation	Result	Denomination
Number of interruptions	$\lambda = \lambda_{av}$	**1**	number per year
Annual interruption time	$U = \lambda_{av} r_{av}\, k_{\lambda r}$	**2.5**	hours per year
Average interruption time	$r = U/\lambda$	**2.5**	hours per interrupt.
Power not supplied (EPNS)	$\lambda_{av} P_{max} k_{\lambda P}$	**47**	kW per year
Energy not supplied (EENS)	$\lambda_{av} P_{max} r_{av} k_{\lambda Pr}$	**112**	kWh per year
Annual interruption costs (EIC)	$\lambda_{av} P_{max} c_{ref}(r) k_{\lambda Prc}$	**5889**	NOK per year
IEAR*)	EIC/EENS	**52.4**	NOK/kWh

*) IEAR = Integrated Energy Assessment Rate, see Ch. 2.

<u>Remark:</u>
The relative time variation used for the industrial load is a typical load profile for industrial loads of type one-shift a day. Such general profiles are used in conjunction with the maximum load for the load point. Thus, the correction factors calculated for general load types may have to be modified according to a different utilization time in the delivery point from the one inherent in the relative profiles. See also Section 8.2.2.2. If the utilization time deviates significantly from the one inherent in the relative profiles used, the correction factors should be corrected with the factor T_{b2}/ T_{b1}. T_{b2} is the actual utilization time in the delivery point, and T_{b1} is the utilization time used in the relative profile. In this particular case the utilization time

is relatively low (3750 hours), giving quite small correction factors. If for example T_{b2} = 5000 hours, the correction factors that include the load in Table 7.4 should be increased by 33 %.

7.2.2 Time dependent correlation

One important purpose of considering the time variation in the variables is to study the influence of the eventual time dependent correlation between the input variables. An indication of the influence on the reliability indices can be found by calculation of the correlation factors for pairs of the variables. Correlation factors are calculated based on the example data presented in Ch. 4. The load profiles for the industrial one-shift and the commercial load from Section 4.3.1 are used with the failure and repair data from Section 4.2 and the relative variation in cost per interruption for the industrial and commercial sectors.

Table 7.6 and Figs. 7.3 and 7.4 give the correlation factors for the industrial and commercial loads, based on all failures in the 6 year period.

Table 7.6 Correlation factors based on all failures (≤ 40 kV).

Variables	Monthly	Weekly	Daily
Number of failures vs duration	0.29	- 0.55	- 0.74
Load vs cost, *industrial* load	--	1.00	0.90
Load vs cost, *commercial* load	0.13	0.82	0.93

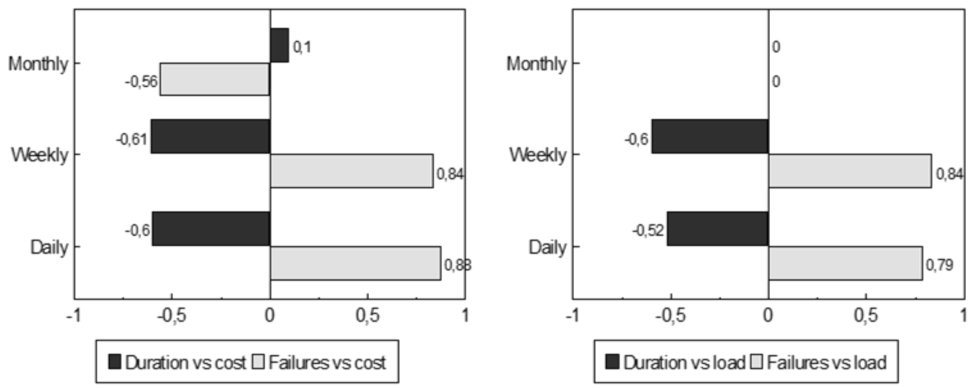


Fig. 7.3 Correlation factors for industrial load, based on all failures (≤ 40 kV).

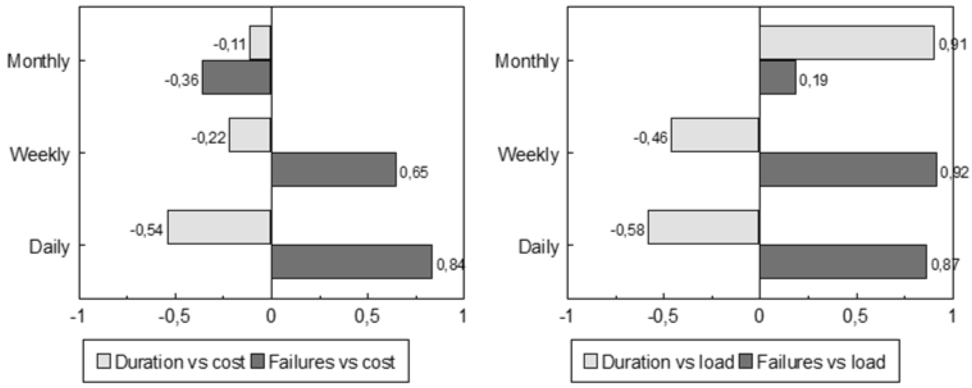


Fig. 7.4 Correlation factors for commercial load, based on all failures (≤ 40 kV).

These correlation factors show that the correlation varies for different time periods. The variations are similar for the two load types, although the factors are different in size. For instance there is a negative correlation between number of failures and the interruption cost on a monthly basis (Figs. 7.3 and 7.4). On a weekly and daily basis there is a stronger and positive correlation between these two variables. For the correlation between occurrence of failures and duration (Table 7.6) the relation is opposite. These relations counteract the correlation between failures and cost in the determination of annual interruption costs, since the cost is a function of duration.

As expected there is a strong positive correlation between the load level and the cost level (Table 7.6), indicating that the cost is a function of the load (cfr. Ch. 2). Therefore the correlation between number of failures and the load level points in the same directions as between failures and cost. This indicates that the power not supplied is influenced by a positive time dependent correlation. If we consider the correlation between the duration and the load, Figs. 7.3 and 7.4 show that this is negative on a weekly and daily basis, and for the commercial load strongly positive on a monthly basis. This relation may influence the energy not supplied (EENS). For these data it seems that EENS is influenced by a strong positive correlation between failures and load and by a less strong negative correlation between duration and load.

The negative correlation between number of failures and duration on a weekly and daily basis (Table 7.6), indicates that the annual interruption time is influenced by a resulting negative correlation.

Correlation factors based on failures on overhead lines and cables are given in Appendix 6. The correlation factors based on overhead failures are in the same order (some are lower and some are higher) and have the same signs as the ones presented here based on all failures. With the data for cable failures a stronger negative correlation is observed on a weekly basis between the duration and the other variables. This is due to the significantly longer durations in the weekend than on weekdays (see Fig. 4.6).

7.2.3 Comparison with the traditional analytical method

A comparison is now made with the traditional expectation method in order to show the influence of the time dependent correlation on the reliability indices. The traditional analytical method is presented in Section 3.3, Eqs. (3.10) and (3.11) for EPNS and EENS, and in Eq. (5.12) for EIC. Using these equations we get the results given below. The indices calculated by the traditional method are marked with a $^{1)}$.

$EPNS^{1)}$	=	43	kW per year
$EENS^{1)}$	=	112	kWh per year
$EIC^{1)}$	=	6171	NOK per year
$IEAR^{1)}$	=	55.2	NOK/kWh

The comparison can be made on the basis of the equations, as shown in the following:

$$\begin{aligned} EPNS &= \lambda_{av} P_{max} k_{\lambda P} \\ &= \lambda_{av} P_{av} \frac{1}{0.43} 0.468 \\ &= EPNS^{1)} 1.088 \end{aligned}$$

$$\begin{aligned} EENS &= \lambda_{av} P_{max} r_{av} k_{\lambda Pr} \\ &= \lambda_{av} P_{av} r_{av} \frac{1}{0.43} 0.432 \\ &= EENS^{1)} 1.005 \end{aligned}$$

$$\begin{aligned} EIC &= \lambda_{av} P_{max} r_{av} c_{Wref} k_{\lambda Prc} \\ &= \lambda_{av} P_{av} r_{av} c_{Wav} \frac{1}{0.43} \frac{1}{1.2} 0.493 \\ &= EIC^{1)} 0.955 \end{aligned}$$

Taking time dependent correlation into account, we get 8.8 % higher EPNS, 0.5 % higher EENS and 4.5 % lower EIC compared with the traditional method. These results are in accordance with the results in Section 7.2.2, indicating that both EPNS and EENS are influenced by a positive correlation (EENS less than EPNS though). The resulting time dependent correlation inflicting EIC seems to be negative, giving lower EIC. In this case the traditional method underestimates EPNS, but overestimates EIC. The result for EENS is quite close for the two methods.

The time dependent correlation influences the size of the correction factors (Table 7.4). Depending on the size of these correction factors, the expectation method taking into account time correlation will give results that differ from the ones calculated by the traditional method. In the base case however, none of the results deviate more than about 9 %.

The size of the correction factors depend on the relation between P_{max} and P_{av}, the relation between c_{Wref} and c_{Wav} and the correlation among the variables. This can be shown by calculating the break-even factors (marked with an ^{e}) giving EPNS = $EPNS^{1)}$, EENS = $EENS^{1)}$ and EIC = $EIC^{1)}$:

$$k_{\lambda P}{}^{e} = \frac{P_{av}}{P_{\max}}$$

$$k_{\lambda Pr}{}^{e} = \frac{P_{av}}{P_{\max}}$$

$$k_{\lambda Prc}{}^{e} = \frac{P_{av}}{P_{\max}} \frac{c_{Wav}}{c_{Wref}}$$

The break-even factors for the industrial load are:

$k_{\lambda P}{}^{e} = k_{\lambda Pr}{}^{e} =$ 0.430
$k_{\lambda Prc}{}^{e} =$ 0.516

These factors are quite close to those in Table 7.4 (except for EPNS). If the correction factors are smaller than the break-even factors, the traditional method overestimates the expectations. The opposite is true if the correction factors are larger, so that there will be underestimation if time dependent correlation is not taken into account.

If the load in the delivery point is changed to a commercial load, the deviations will be different. We get the following results using data from Chapter 4 (CDF for commercial sector is given in Fig. 7.2):

$k_{\lambda P}$ = 0.480
$k_{\lambda Pr}$ = 0.485
$k_{\lambda Prc}$ = 0.668
b = 1.378

Table 7.7 Results for commercial load.

Reliability index	Expectation with correlation	Traditional expectation [1)]
EPNS, kW per year	48	43
EENS, kWh per year	126	112
EIC, NOK per year	6918	6941
IEAR, NOK/kWh	54.9	62.1

The results in Table 7.7 are based on the average time variations in commercial load and specific cost for commercial sector, given in Chapter 4.

A comparison with the traditional method gives:

EPNS = $EPNS^{1)}$ 1.116
EENS = $EENS^{1)}$ 1.128
EIC = $EIC^{1)}$ 0.997

Taking time dependent correlation into account we now get 11.6 % higher EPNS, 12.8% higher EENS and 0.3 % lower EIC. The break-even factors for the commercial load are:

$k_{\lambda P}{}^{e} = k_{\lambda Pr}{}^{e} =$ 0.430
$k_{\lambda Prc}{}^{e} =$ 0.671

The correction factors $k_{\lambda P}$ and $k_{\lambda Pr}$ are larger than the break-even factors while $k_{\lambda Prc}$ is almost equal to $k_{\lambda Prc}{}^{e}$. Thus the traditional method in this case underestimates EPNS and EENS, but EIC is practically equal for the two methods.

The results for these two load types show the influence of load variation on the reliability indices. The commercial load has a greater relative variation than the one-shift industry and the factor $k_{\lambda Prc}$ is 36 % higher. This results in 17 % higher EIC than for the industrial load even if the specific cost for 2.6 hours is 13 % lower.

The results for the commercial load are in accordance with the calculated correlation factors in section 7.2.2.

7.2.4 Application of specific interruption cost

In the calculation of EIC$^{1)}$, the *average* specific cost (for 2.6 hours) is used. For the industrial sector with one shift the average cost is 1.2 times the specific cost at reference time yielding higher EIC$^{1)}$ and IEAR$^{1)}$ than in Table 7.5. Time variation in the *specific* interruption cost is explained in Chapter 4.

More often in practice, however, the specific cost *at reference time* is (or has been) used. This gives EIC$^{2)}$ = 5143 NOK, which is approx. 14 % lower than in Table 7.5, representing an underestimation of 14 %. IEAR$^{2)}$ equals 46.0 NOK/kWh, which is equal to the specific cost at reference time (c_{Wref}) for 2.6 hours.

From this we see that IEAR$^{1)}$ is 1.2 times IEAR$^{2)}$, while IEAR in Table 7.5 is 1.14 times IEAR$^{2)}$. This factor is equal to 'b' in Table 7.4. The b-factor includes the additional correlation between specific interruption cost and EENS and corrects for using the reference cost. In other words: both IEAR and IEAR$^{1)}$ represent the average specific cost on an annual basis, but IEAR includes the time dependent correlation. The different IEARs are expressed in the following:

IEAR$^{2)}$ = c_{Wref} = 46.0 NOK/kWh
IEAR$^{1)}$ = c_{Wav} = 1.2 c_{Wref}
IEAR = b c_{Wref} = 1.14 c_{Wref}.

If the specific reference cost at reference time for commercial sector is used in the calculation of EIC, we get EIC$^{2)}$ = 4450 NOK, which represents an *underestimation* of approx. 45 %. This is due to the fact that $c_{Wav} = 1.56 c_{Wref}$ for the commercial load. In that case IEAR$^{2)}$ would be 39.8 NOK/kWh which is equal to the specific cost at reference time (c_{Wref}). The connection between the different IEARs for this load is as follows:

IEAR$^{2)}$ = c_{Wref} = 39.8 NOK/kWh
IEAR$^{1)}$ = c_{Wav} = 1.56 c_{Wref}
IEAR = b c_{Wref} = 1.38 c_{Wref}.

The influence of the time dependent correlation on the Integrated Energy Assessment Rate (IEAR) is shown in the following:

Industrial load:

$$\frac{1.14\, c_{Wref}}{1.2\, c_{Wref}} = 0.95$$

Commercial load:

$$\frac{1.38\, c_{Wref}}{1.56\, c_{Wref}} = 0.88$$

Time dependent correlation accounts for a reduction in IEAR of 5 % and 12 % respectively compared to the *average* specific cost.

From these two simple examples we see that application of c_{Wref} leads to an underestimation of annual interruption costs, while c_{Wav} may lead to an overestimation compared to taking time dependent correlation between the variables into account. Use of reference cost yields the most significant difference in EIC, 14 % and 45% respectively for the two categories. If the annual average specific cost is used, the deviations are small, 0.3 % and 4.5% respectively, in these examples.

7.2.5 Influence of nonlinear cost functions

In the expectation method for radial systems described in Section 6.2.2 and illustrated in the previous sections, there is an approximate representation of the time dependency between specific cost and duration. Due to lack of data on time variations for all components and delivery points in distribution systems, it is convenient for practical purposes to use precalculated correction factors together with the traditional reliability methods.

The influence of this approximate representation is illustrated for two example cost functions shown in Fig. 7.5, one which is linear and another is highly nonlinear (piecewise linearity is assumed). In the expression for the annual cost in Eq. (6.2) the time dependency between the duration and the specific cost is represented by the product of their relative factors in different time periods, while the specific cost is represented as a function of the average repair time on an annual basis (r_{av}). This expression is compared with the more accurate representation, b) below:

$$a)\; k_{rk}\, k_{ck}\, c_{Wref}(r_{av})$$
$$b)\; k_{ck}\, c_{Wref}(k_{rk}\, r_{av})$$

where

- k = time period
- k_{rk} = relative repair time in period k, referred to r_{av}
- k_{ck} = relative specific cost in period k, referred to c_{Wref}

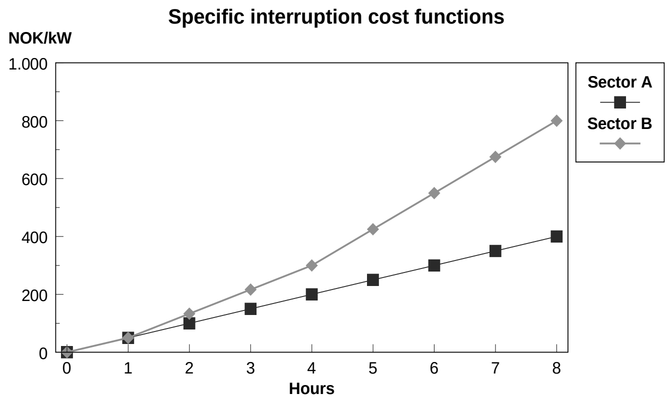


Fig. 7.5 Examples of specific cost functions.

The comparison is made for two different interruptions, both with an average interruption time of 3 hours. The following relative factors are used:

1) $k_{rk} = 0.8$ $k_{ck} = 1.2$

2) $k_{rk} = 1.5$ $k_{ck} = 1.0$.

The specific cost for the two interruptions are calculated according to the two methods above and summarized:

a) Sector A: 369 NOK/kW
Sector B: 533 NOK/kW

b) Sector A: 369 NOK/kW (0 %)
Sector B: 563 NOK/kW (+ 6 %).

The two methods give no difference for the linear cost function (sector A), while method b) gives 6 % higher cost for the nonlinear cost function. The approximate description in method a) has no influence when the cost function is linear, but it may be significant for delivery points with nonlinear cost-functions. If that is the case, the analytical method for meshed systems may be used for such delivery points. This method accounts for the time dependency between the specific cost and the duration in accordance with method b) above.

7.3 Monte Carlo simulation method

The main purpose of the development of the Monte Carlo simulation method was to handle the stochastic variations in the variables in addition to the time-varying failure rate and the time variation in other variables, and thus to provide more information than expectation values only. The probabilities of different outcomes of for instance interruption time or cost per interruption, will be of particular interest in the evaluation of results compared to reliability or cost restrictions.

In this section the expectations for the base case are presented and a comparison is made with the analytic calculations in the previous section. Next the dispersions in the reliability indices are determined, and an example of time variation in the indices is included.

Summary of results:

The Monte Carlo simulation method gives approximately the same annual expectation values as the analytical method including time dependent correlation. With 1000 simulated failures for each outage event the deviations are within ± 5 % from EIC calculated by the analytical method. The difference between EIC from the Monte Carlo method and the analytical method will depend on the nonlinearity of the cost function. See Section 7.5.2.

The results demonstrate that in a single year values significantly larger than the expectation values are likely to occur. For instance are the 90 percentiles for ENS and IC about 125 % higher than the mean. The probability distribution of the interruption time seems to be the dominant factor for the probability distributions of ENS and IC. The uncertainty in EIC described by a 95 % confidence interval is about ± 7 % of the mean.

7.3.1 Number of simulations

The Monte Carlo simulation method is prototyped in Microsoft Excel 5.0. The prototype has no automatic stopping or convergence criterion. The number of simulations is therefore chosen manually. Expectation values within ± 5 % from the analytical expectations are considered acceptable in order to illustrate the methods.

As was mentioned in Chapter 6, no particular efforts have been made to get a certain level of accuracy in the calculations. When the method is implemented in a software package with a suitable programming language, convergence criteria can be set and the numbers of simulations automatically determined according to these criteria. To improve computation efficiency, there are different variance reduction techniques available for this purpose [13].

The computation time for 1000 simulated failures is about 40 seconds on a 486 DX 66 MHz PC (including result presentation). On a Pentium 133 MHz PC the computation time is reduced to about 6 seconds. Computation time for 2500 simulations is about 89 and 14 sec. respectively. With respect to computation time the difference between those two computers seems to be about 6:1 for this method.

The occurrences of failures are drawn randomly from the conditional probabilities given by the average time variation in failures (q_λ - factors, see Section 6.3.1). Since these are average factors for several years of statistics and the average number of failures is considered constant equal to λ, it is not necessary to draw the number of failures each year. This means that the number of simulations can be chosen independently from the number of years. If it is of interest to explore the year by year variations, the number of failures per year should be determined randomly as well. This can easily be obtained when the method is implemented in a computer program.

One simulation represents one failure in this context. With for instance $\lambda = 4$, 1000 simulations would represent 250 years. It is found that a sample size of about 1000 failures will give acceptable expectation values within ± 5 %. If there are more components (or cuts) involved in the supply situation, each component should be simulated by the order of 1000 failures, as we shall see later.

Examples of reproduction of the time variation in failures are shown in Figs. 7.6 - 7.8. 1000 failures are simulated based on the values in Tables 7.1 - 7.3. A visual inspection of the figures show that they are in accordance with the q_λ-factors, see Figs. 4.2 - 4.4. Thus the model is found to be able to reproduce the data basis reasonably with a number of 1000 simulations, for the purpose of illustrating the method.

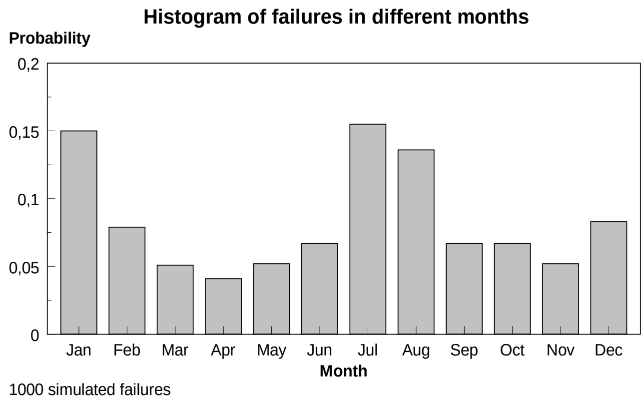


Fig. 7.6 Histogram of failures in different months, 1000 simulated failures.

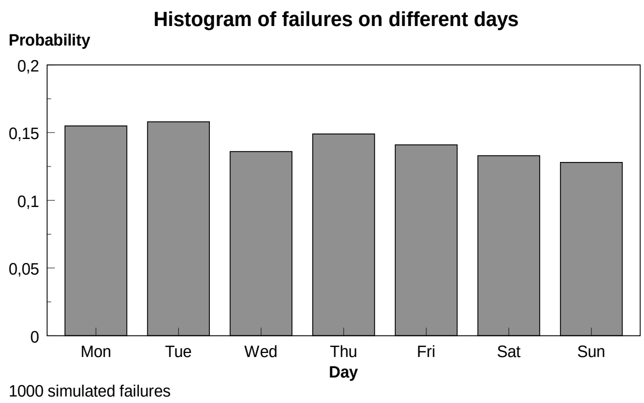


Fig. 7.7 Histogram of failures on different days, 1000 simulated failures.

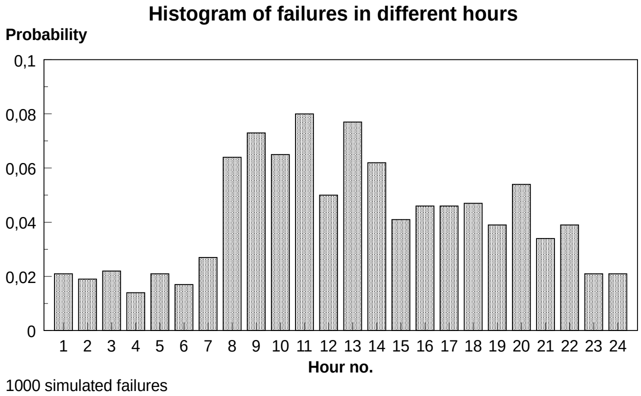


Fig. 7.8 Histogram of failures in different hours of the day, 1000 simulated failures.

7.3.2 Expectation values

Expectation values are calculated for a simulation of 1000 failures and given in Table 7.8. The data in Tables 7.1 - 7.3 are used.

Table 7.8 Expectation values calculated by the Monte Carlo simulation algorithm, base case.

Reliability index	Expectation	Deviation from analytical method	Std. dev. for expectation
U	2.5 hours/year	- 4.5 %	0.1 hours/year
EPNS	47 kW/year	- 0.3 %	0.5 kW/year
EENS	107 kWh/year	- 4.4 %	4.2 kWh/year
EIC	5698 NOK/year	- 3.3 %	203 NOK/year
IEAR	53.0 NOK/kWh	+ 1.2 %	

The table shows that for this run the deviations in expectation values are below 5 %. The deviations vary from run to run and are in the ± (0-5 %) domain most of the time.

In Table 7.8 the standard deviations in the expectation values are also given. The standard deviations are indicators of the accuracy in the expectations, or in other words measures of statistical uncertainty in the expectations. From classical statistical literature we find that the mean of a sample for the stochastic variable X is

$$\bar{x} = \frac{1}{M}\sum_{i=1}^{M} x_i$$

The variance of the mean is

$$Var(\bar{x}) = \frac{Var(x)}{M}$$

where Var(x) is estimated by

$$Var(x) = \frac{1}{M-1}\sum_{i=1}^{M}(x_i - \bar{x})^2$$

This gives the estimated standard deviation (or standard error) of the mean

$$sd(\bar{x}) = \sqrt{\frac{Var(x)}{M}}$$

where M is the number of simulations (or sample size).

If we repeat the simulations a great number of times, the expectations can be considered to be normally distributed, according to the central limit theorem [14]. This allows us to calculate (1-2α) *100 % confidence intervals for the different reliability indices, based on the standard deviations and the $z^{(\alpha)}$ percentile points of a standard normal distribution. For a 90 % and 95 % interval, $z^{(\alpha)}$ equals 1.645 and 1.960 respectively. The 95 % confidence intervals for EPNS, EENS and EIC are shown in Table 7.9, based on the calculated standard deviations in Table 7.8.

Table 7.9 95 % confidence intervals for expectations from Monte Carlo simulation of base case, 1000 simulated failures.

Index	Mean	Confidence interval, 95 %
EPNS	47 kW/year	[46, 48] ± 2 %
EENS	107 kWh/year	[99, 116] ± 8 %
EIC	5698 NOK/year	[5300, 6095] ± 7 %

With a confidence level of 95 %, the expectations are found to be within the intervals in Table 7.9. The width of the confidence intervals is given in percentage of the mean.

7.3.3 Stochastic variations

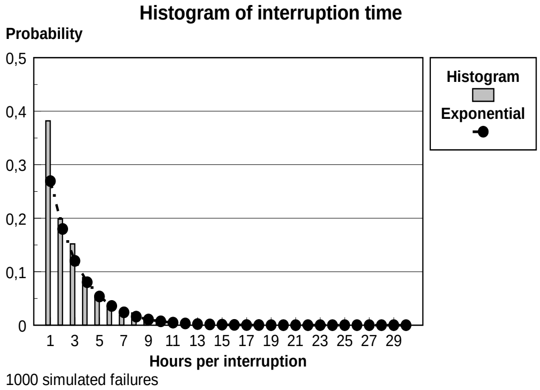
The stochastic variations for the different input variables are given in Table 7.10. The expectation values in a particular month, weekday and hour are given by Eqs. (5.5), (5.7), (5.8) and (5.10).

Table. 7.10 Stochastic variations in failures, repair time, load and specific interruption cost, base case.

Variable	Expectation	Prob. distribution	Parameters
Failures*)	$\lambda_{h,d,m}$		
Repair time	$r_{h,d,m}$	Exponential	$1/r_{h,d,m}$
Load	$P_{h,d,m}$	Normal	$P_{h,d,m}$, σ_P = 10 %
Specific cost	$c_{h,d,m}$	Normal	$c_{h,d,m}$, σ_c = 20 %

*) The stochastic variation in failures from year to year is not included in these examples

Stochastic variation in the reliability indices results from random drawings from the probability distributions for the individual variables in Table 7.10. The stochastic variations in the reliability indices are shown by histograms covering 1000 simulations, together with the cumulative probability distributions, in Figs. 7.9 - 7.12. The y-values in the histogram represent the relative portion of the sample located in the interval *from* the previous x-value including the *actual* x-value.



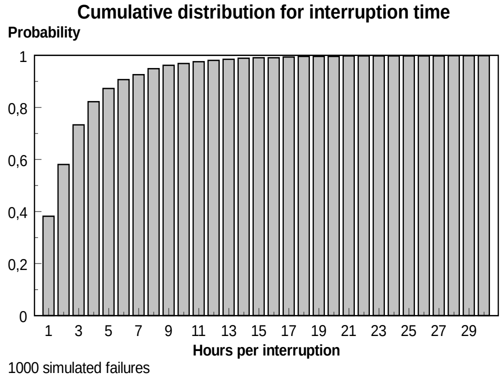


Fig. 7.9 Interruption time for 1000 simulated failures. r ~ exp $(1/r_{h,d,m})$.

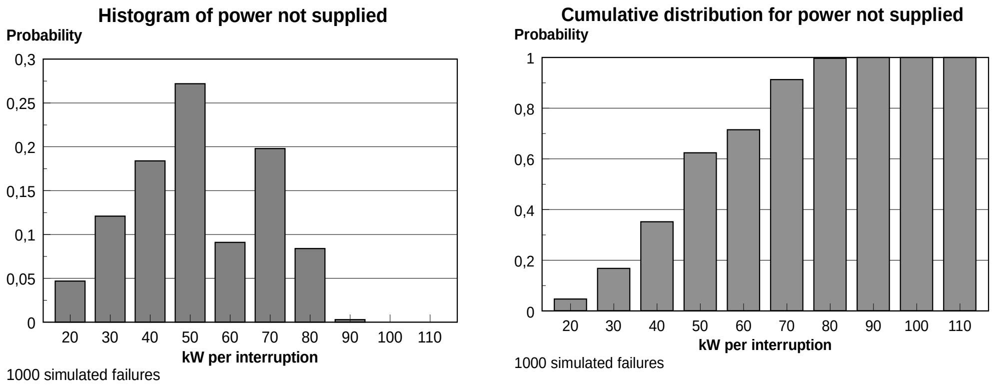


Fig. 7.10 Power not supplied, 1000 simulated failures. P ~ N($P_{h,d,m}$, 10%).

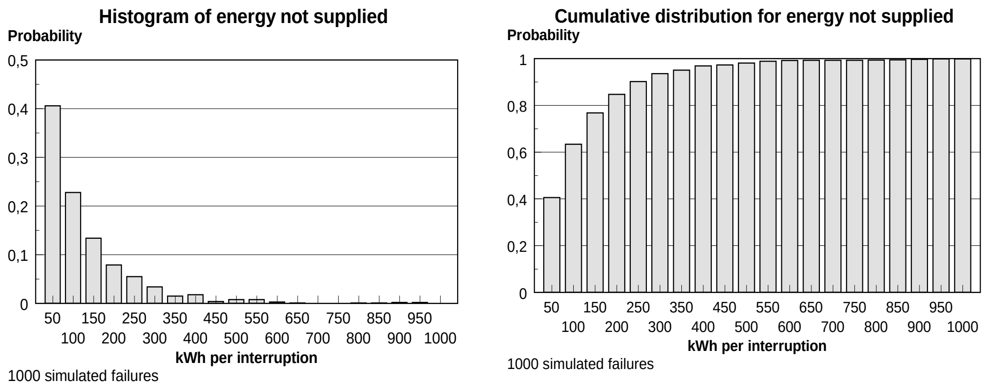


Fig. 7.11 Energy not supplied, 1000 simulated failures.

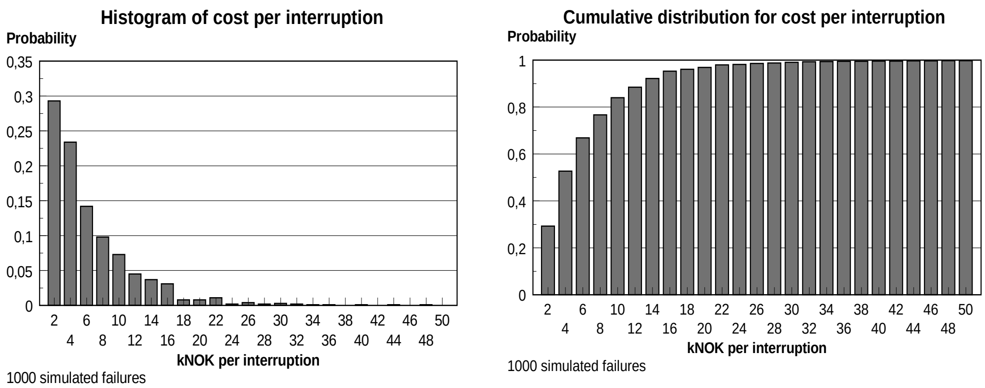


Fig. 7.12 Cost per interruption, 1000 simulated failures. c ~ N($c_{h,d,m}$(r), 20%).

The figures show the indices per interruption. Since there is one interruption (failure) per year on average in the base case, these also represent the *annual* interruption indices.

The histograms and cumulative probability functions provide information on which values are likely to occur for the individual interruptions, and they give an indication of the probability of certain outcomes. These probabilities can be calculated. As examples the 50- and 90 percentiles are calculated for different indices and given in Table 7.11.

Table 7.11 50- and 90 percentiles for base case, 1000 simulated failures. Relative deviation from expectation in brackets.

Index	Expectation	50 percentile		90 percentile	
r	2.5	1.5	(- 40 %)	5.6	(+ 124 %)
PNS	47	44	(- 5 %)	69	(+ 48 %)
ENS	107	69	(- 36 %)	244	(+ 127 %)
IC	5698	3757	(- 34 %)	12745	(+ 124 %)

In 90 % of all interruptions, the annual cost will be below NOK 12745, and in 90 % of the interruptions the interruption time will be below 5.6 hours.

The histogram for interruption time in Fig. 7.9 has the characteristic form of an exponential distribution. The exponential distribution is plotted in the figure. The probability distribution of r seems to be the dominant factor for the empirical probability density functions for the energy not supplied and the interruption cost, Figs. 7.11 and 7.12. The Normal distributions of load and specific interruption cost seem to have little influence. This will be discussed in a later section. The dominant influence of interruption time on the specific cost is demonstrated in Fig. 7.13, giving the histogram for the specific cost.

The empirical probability density (or the histogram) for power not supplied (PNS) in Fig. 7.10 does not show to have the form of a Normal distribution. PNS is determined by the load variation and the probabilities of occurrence of failures in addition to the normality assumption.

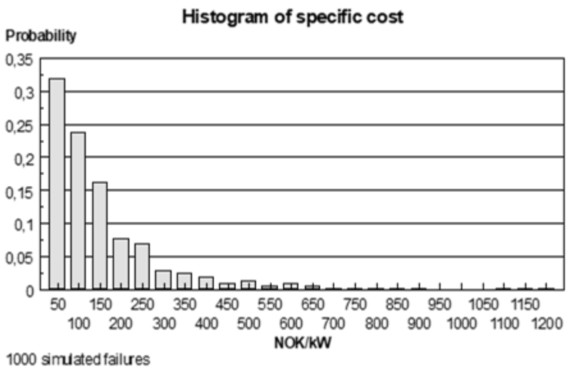


Fig. 7.13 Specific cost per interruption, 1000 simulated failures. c ~ N($c_{h,d,m}$, 20 %)

The specific cost is assumed to follow a Normal distribution with a standard deviation of 20 %. As the specific cost is a function of the duration, the distribution of the duration will dominate the distribution of the specific cost, even with a high standard deviation.

The influence of the nonlinearity of CDF on the resulting stochastic variation in IC is checked using CDF for commercial sector for the base case. Fig. 7.2 shows that the industrial CDF is practically linear, while there is some nonlinearity in the commercial CDF. EIC is calculated to be NOK 5101 by the analytical method, for the industrial load with the commercial CDF. Two different runs with the Monte Carlo method give:

1) EIC = 5274 NOK
   50 percentile = 3197 (- 39 %)
   90 percentile = 11778 (+ 123 %)
   95 % conf.int. = [4889, 5660] ± 7 %

2) EIC = 5065 NOK
   50 percentile = 3227 (- 36 %)
   90 percentile = 12009 (+ 137 %)
   95 % conf.int. = [4718, 5411] ± 7 %.

The form of the histogram for IC is unchanged. The percentiles and the confidence interval deviate in the same order relatively to the expectation, as for the base case (see Table 7.11). However, the results seem to be more unstable with the nonlinear CDF, indicating that the number of simulated failures should be increased. EIC with the commercial cost function seems to be little influenced by the nonlinearity of the CDF. This may be due to the quite small non-linearity in the Norwegian CDFs. See also Section 7.5.2.1 where both the shape of the probability distribution for repair time and the cost functions are changed.

7.3.4 Time variation in reliability indices

As examples of the time variation in reliability indices, the distribution of the annual energy not supplied and the annual interruption cost are shown on a monthly and daily basis in Figs. 7.14 and 7.15.

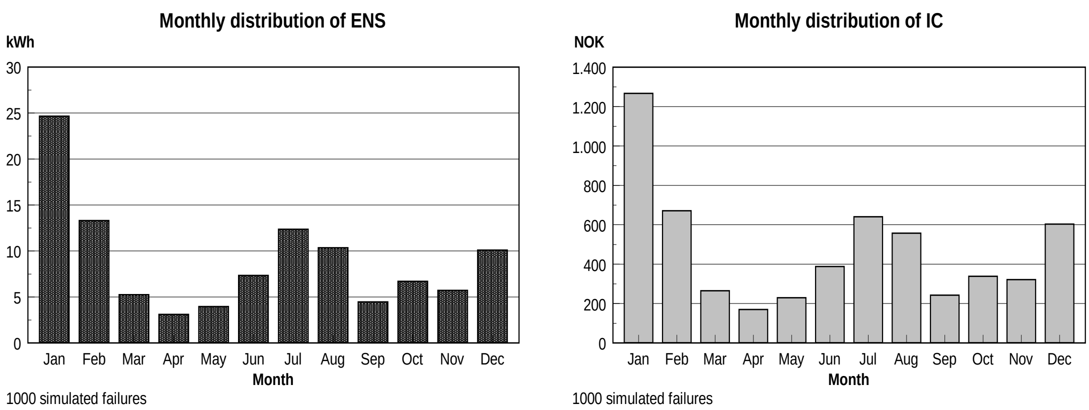


Fig. 7.14 Monthly variation in ENS and IC.

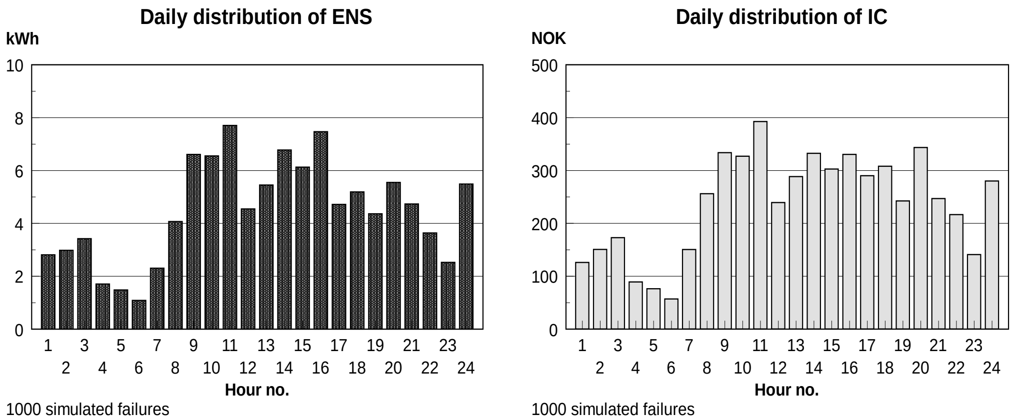


Fig. 7.15 Daily distribution of ENS and IC.

Figs. 7.14 and 7.15 show that there is a considerable time variation in both ENS and IC. The form of the time profiles are quite similar to the histogram of failures in Figs. 7.6 and 7.8. There is a difference on a daily basis however, giving a quite uniform interruption cost between 8 a.m. and 8 p.m. The time variation in the annual cost is influenced by the time variation in four variables: failures, repair time, load and specific cost. The time profiles used in the base case are shown in Chapter 4.

The portion of ENS or IC in different hours of the day (Fig. 7.15) should be interpreted as the amount of ENS or IC if the interruption occurs in a particular hour.

7.4 Fuzzy description of uncertainties

By the handling of time variation in the four variables that determine the annual interruption costs, the analytical expectation method and the Monte Carlo simulation method provide better estimates of the expectation values than the traditional method. In this section we will illustrate the influence of uncertainties in the input variables by application of the fuzzification procedure described in Section 6.4. This method gives information about the uncertainties in the reliability indices based on some judgements on uncertainty in the different input variables.

The membership functions give a visual expression of the possible intervals where the expectations are located. The corners of the membership functions give directly the possible intervals based on the whole space of possible outcomes, or intervals can be defined where the membership is above a certain confidence level α. An example is given for EIC for a confidence level α = 0.5, i.e., an interval with a higher membership than 50 %: EIC lies between about NOK 2000 and 10500 with a crisp EIC of NOK 6000 per year.

7.4.1 Fuzzification of the input variables

All the input variables are represented by symmetrical and trapezoidal membership functions. The corners a_1, a_2, a_3 and a_4 of the membership functions are given by the values in Table 7.12. These are percentages of the reference values. The membership functions are shown in Fig. 7.16.

Table 7.12 Corners of membership functions for failures, repair time, load and specific interruption cost.

Variable	a_1	a_2	a_3	a_4
Failures, λ	-50 %	-20 %	+20%	+50 %
Repair time, r	- 60 %	-20 %	+20 %	+60%
Load, P	-10 %	-5 %	+5 %	+10 %
Specific cost, c	-75 %	-50 %	+50 %	+75 %

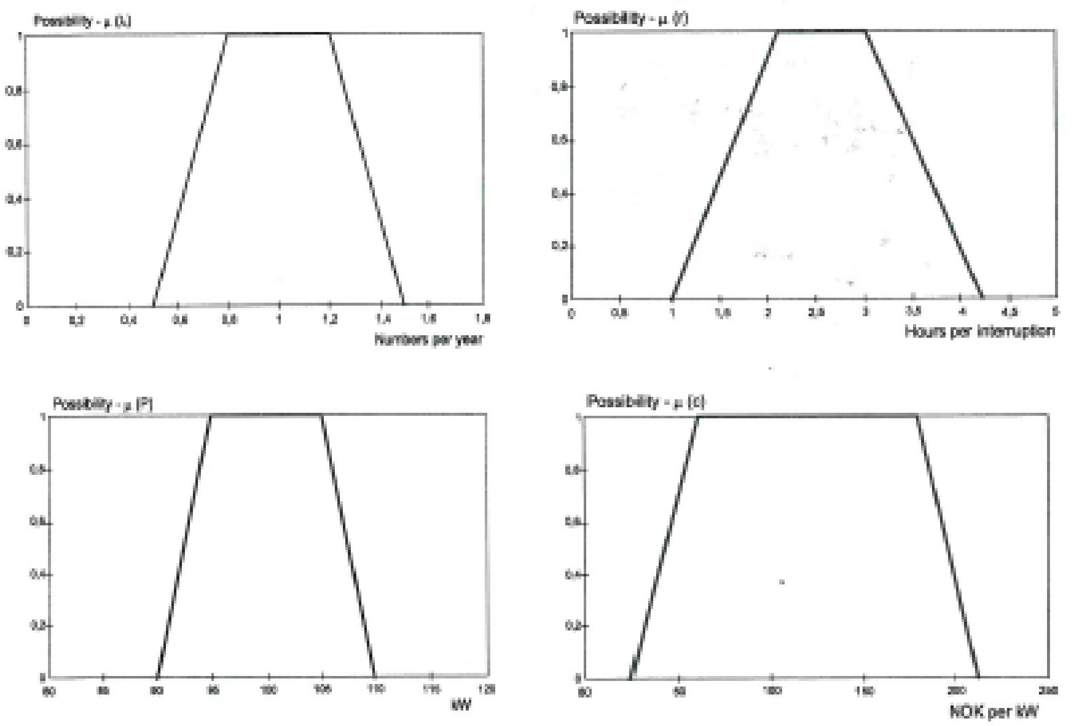


Fig. 7.16 Membership functions for failures, repair time, load and specific cost.

7.4.2 Crisp (expectation) values

The fuzzy reliability indices are calculated by operations on fuzzy numbers as described in Section 6.4. The time variations are handled as earlier, by the correction factors. The crisp values of the different reliability indices are calculated by the mean of the two corners with membership equal to 1.0, Eq. (6.29). The crisp values are calculated both with crisp lambda (=1) and fuzzy lambda, given in Table 7.13. The deviations from the values calculated by the analytical expectation method are also shown in the table.

Table 7.13 Crisp reliability indices for base case.

Reliability index	With crisp lambda	With fuzzy lambda
U, hours per year	2.5 (0 %)	2.6 (4 %)
EPNS, kW per year	47 (0 %)	47 (1 %)
EENS, kWh per year	114 (1 %)	119 (6 %)
EIC, NOK per year	6037 (2.5 %)	6685 (13.5 %)
IEAR, NOK per kWh	53.2 (1.5 %)	56.1 (7 %)

With a crisp average number of failures ($\lambda = 1$) we get practically equal expectations (or crisp indices) as with the analytical expectation method in Table 7.5. This is due to the choice of symmetrical membership functions relative to the expectations. There is a slight difference which is due to the approximate calculation of crisp values based on the corners of the membership function.

When the average failure rate is fuzzified, the crisp indices are increased. This is expected to happen, since all indices involve a multiplication with λ, yielding wider membership functions and a shift of the corners. This is visualized by the membership functions in next section.

7.4.3 Membership functions

The membership functions for annual interruption time (U), EPNS, EENS and EIC are given in Figs. 7.17 - 7.20, both with a crisp and a fuzzy lambda. These functions are drawn on basis of the calculated corners, given in Table 7.14.

Table 7.14 Corners of membership functions, base case, with crisp and fuzzy lambda.

Reliability index	With crisp λ				With fuzzy λ			
	a_1	a_2	a_3	a_4	a_1	a_2	a_3	a_4
U, hours per year	1.0	2.0	3.0	4.1	0.5	1.6	3.7	6.1
PNS, kW per year	42	45	49	52	21	36	59	77
ENS, kWh per year	41	85	142	198	20	68	170	297
IC, NOK per year	1325	2798	9276	11337	663	2238	11131	17006

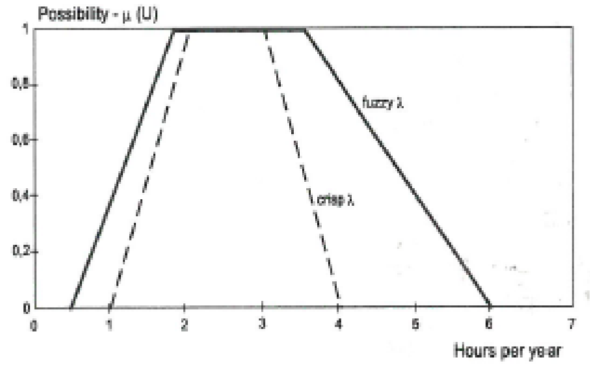


Fig. 7.17 Membership for annual interruption time, base case.

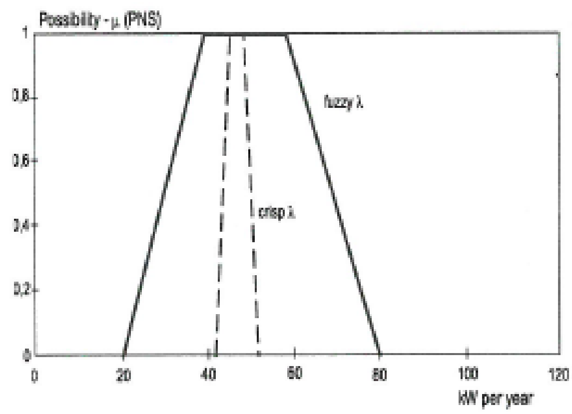


Fig. 7.18 Membership for power not supplied, base case.

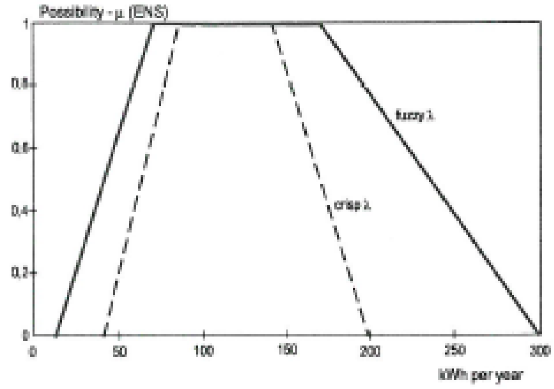


Fig. 7.19 Membership for energy not supplied, base case.

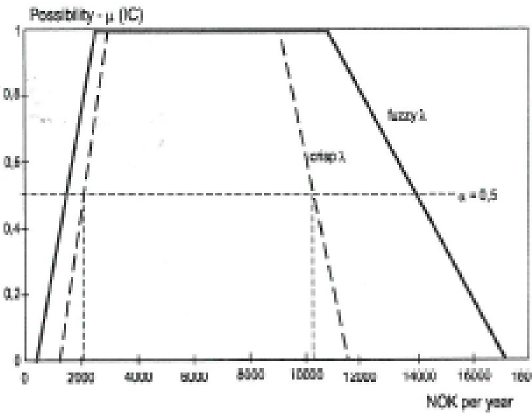


Fig. 7.20 Membership for annual interruption cost, base case.

The membership functions presented in Figs. 7.17 - 7.20 give the uncertainties in the reliability indices based on the uncertainties in the input variables from Table 7.12. In this example the deviations from the input variables' expectations are chosen quite large, representing a quite large uncertainty. This results in wide memberships for the indices, especially for ENS and IC. If narrower memberships are chosen for some of the input variables, the output memberships will be narrower as well. This can be seen by comparison of the corners in Table 7.14 with crisp and fuzzy λ.

Values with membership equal to 1.0 all have equal possibility of occurrence as they have a full membership. This means that the corners a_2 and a_3 give an interval for the expectation value with possibility equal to 1.0. In addition there is some grade of possibility that the expectations will be lower or higher than the values associated with these two corners.

As an example we can define a confidence level $\alpha = 0.5$ for EIC, i.e. an interval with a higher membership than 50 %. Then from the membership with a crisp λ, we see from Fig. 7.20 that EIC lies between about NOK 2000 and 10500 per year.

7.5 Influence of time variation and stochastic variations

The time variation is important for the magnitude of the expectation values EENS and EIC, but does not have any influence on the stochastic variations, i.e., the dispersion and the form of probability distributions for the reliability indices. The stochastic variation, on the other hand, does not affect the expectation values as far as the mean of the probability distribution is unchanged, except for cases with a significant nonlinearity in the cost function. Due to the assumed statistical independency, the time variation and stochastic variation can be studied separately. The stochastic variation is therefore in principle an additional component, giving additional information to the expectations. The dependency among the variables in each time interval is given by the covariance and inflicting the expectation as shown in Chapter 5.

7.5.1 Time variation

The influence of time variation is illustrated by omitting the stochastic variations. The time profiles are changed for the different input variables to get changes in the estimated expectations for the base case.

Summary of results:

The results in this section indicate that the time variation in input variables *may* have a significant influence on EIC, depending on the type and magnitude of the variation. Taking only monthly or weekly time variation into account will underestimate EIC by 14 % and 25 % respectively, while only daily variation will overestimate EIC by 14 %. If different time profiles for failures and repair time are used, by for instance using profiles for overhead lines and cables instead of the base case profiles, the results deviate not more than ± 10 %. Using the load variation for the commercial load instead of the industrial load in the base case gives 22 % higher EIC. If time variation in the specific cost is omitted, EIC will be underestimated by 12 % (industrial load) and 27 % (commercial load) if the reference cost is used. Using a constant average cost gives 5 % and 13 % higher EIC respectively.

7.5.1.1 Influence of monthly-, weekly- and daily profiles

The influence of time variation is different on a monthly-, weekly- and daily basis. With the base case data, the month-, week- and day-factors are calculated separately and given in Table 7.15. It may be recalled that the load reference is different for the three factors: P_{av} for monthly- and weekly variation and P_{max} for daily variation.

Table 7.15 Influence of the separate monthly, weekly and daily profiles on EENS and EIC.

Profile	$k_{\lambda Pr}$	$k_{\lambda Prc}$	EENS	EIC
Monthly	0.977	0.990	109 (- 3 %)	5092 (- 14 %)
Weekly	0.995	0.884	111 (- 1 %)	4547 (- 25 %)
Daily	0.444	0.566	115 (+ 3 %)	6770 (+ 14 %)

EENS and EIC are calculated using the individual factors and the corresponding reference values. These indices are shown in Table 7.15 with the relative deviation from base case. The results show that EENS is only slightly influenced by considering only one of these time variations. EIC will be underestimated taking only the monthly- or weekly variation into account and overestimated taking only the daily variation into account.

7.5.1.2 Time profiles for failure rate and repair time

The general network component supplying the delivery point is exchanged by an overhead line or a cable respectively, having *different time profiles* for failures and repair time, but the *same average failure rate and repair time*. Calculations are made with variation in overhead failures together with the base case repair time variation, with base case variation in failures together with the overhead repair time variations etc. The results are compared in Table 7.16 with the base case expectations from Table 7.5. The time profiles for overhead line and cable are shown in Chapter 4. Examples of monthly variation are given in Figs. 7.21 and 7.22.

Table 7.16 Expectations for overhead line and cable, industrial load.

Index	Base case	Overhead line		Cable	
		Failures	Repair time	Failures	Repair time
EPNS, kW per year	47	46 (-1 %)	47 (0 %)	47 (+1 %)	47 (0 %)
EENS, kWh per year	112	123 (+10 %)	102 (-9 %)	111 (-1 %)	123 (+ 9 %)
EIC, NOK per year	5889	6468 (+10 %)	5313 (-10 %)	5843 (-1%)	6455 (+ 10%)

Overhead failures with base case repair time variation or base case failures with overhead repair time variation give about the same deviation from the base case results, with opposite signs. Cable failures with base case repair time variation give negligible deviations, but base case failures with cable repair time variation give a deviation up to 10 %.

Although the deviations in this example are not higher than ± 10 %, it illustrates that other profiles for failures or repair time *may* lead to an increase or decrease in the expectations.

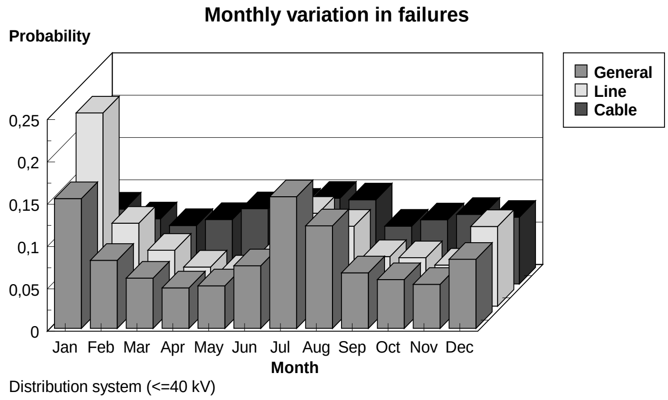


Fig. 7.21 Monthly variation in failures.

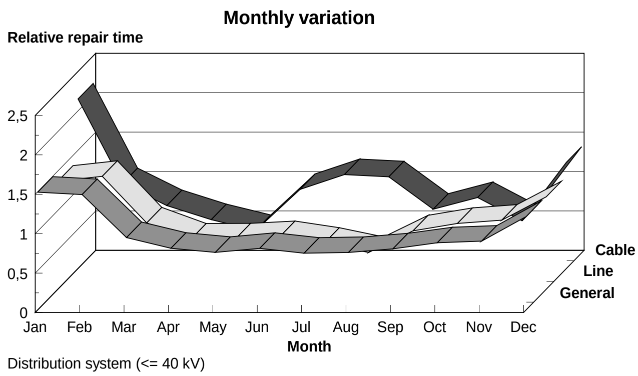


Fig. 7.22 Monthly variation in repair time.

7.5.1.3 Load profiles

The influence of different load profiles is illustrated in Section 7.2 using commercial load compared to the industrial load in the base case. Of these two types of load, the commercial load has the largest relative load variation as was shown in Chapter 4. Table 7.17 gives a summary of expectations for the two different load types. In this example, the load variations for the commercial load are used together with *the specific reference cost for industry* (base case). It may be recalled that the relative variation in specific cost depends on the relative load variation, and therefore the relative variation in *absolute cost* for the industrial sector is used to calculate the relative variation in specific cost with the commercial load.

Table 7.17 Expectations for base case with industrial CDF with relative load variations for the commercial load.

Index	Industrial load (base case)	Commercial load
EPNS, kW per year	47	48 (+ 3 %)
EENS, kWh per year	112	126 (+ 12 %)
EIC, NOK per year	5889	7181 (+ 22 %)
IEAR, NOK/kWh	52.4	56.9 (+ 9 %)

Table 7.17 gives larger EIC and IEAR than in Table 7.7 for the commercial load in Section 7.2. This is due to the choice of the industrial CDF (reference cost).

The results show that load variations can have a significant influence on the expectation values, and particularly the annual interruption cost is sensitive to this aspect.

7.5.1.4 Cost variation

The influence of time variation in specific interruption cost is demonstrated in Section 7.2 using the *traditional* expectation method. EIC is calculated using both the *reference* cost and the *average* cost on an annual basis. Application of reference cost in the traditional method underestimates the annual cost by 14 % for the industrial load, while application of average cost gives practically the same result compared to taking time dependent correlation into account. The corresponding result for the commercial load, using reference cost in the traditional method, represents an underestimation of 45 %. The average cost gives practically equal result for the two methods.

By omitting time variation in the specific cost in the developed expectation method (section 6.2) we get the following results, using the constant reference cost and the constant average cost respectively. A constant specific cost means that the relative time variation is equal for the load and the cost per interruption.

For the base case industrial load, compared with Table 7.5:

EIC_{ref} = 5166 (- 12 %)
EIC_{av} = 6199 (+ 5 %).

For commercial load, compared with Table 7.7:

EIC_{ref} = 5021 (- 27 %)
EIC_{av} = 7833 (+ 13 %).

7.5.2 Stochastic variation

Base case results including stochastic variations are presented in Section 7.3. The influence of stochastic variations are illustrated in this section by changing the dispersions or the type of distributions for the input variables. The mean of the distributions are not changed, thus giving the same expectation values for the reliability indices (there may be an exception for EIC when the cost function CDF is significantly nonlinear).

Due to the inherent randomness of the Monte Carlo process and the limited number of simulations, we will not get exactly the same expectation values as in Sections 7.2 or 7.3. The expectation values are aimed at being within ± 5 % from the analytical expectations. The number of simulations are 1000 failures per run.

Summary of results:

The shape of the probability distribution for annual interruption cost (IC) is dominated by the shape of the probability distribution for the interruption time. Results indicate that the expectation EIC is also influenced by the shape of the probability distribution of interruption time when the cost function is nonlinear. Simulations are performed with both exponentially and lognormally distributed repair times. With nonlinear cost functions, the difference in results is about 6 % in these examples. The load dispersion has practically no influence on the dispersion in IC (radial system), percentiles and confidence intervals are unchanged (relatively). With a highly skewed discrete probability distribution for the specific cost, the 50 percentile for IC is changed from - 40 % to - 100 % from the expectation and the confidence interval for EIC is increased from ± 7 % to ± 19 %, compared to using a normally distributed specific cost. The shape of the probability distribution for IC is highly influenced by the skewness of the discrete distribution for the specific cost.

7.5.2.1 Repair time

The distribution of repair time has the dominating influence on the distribution of the individual ENSs and ICs (Figs. 7.11 - 7.12). Instead of an exponential distribution, a lognormal- and a Gamma distribution are chosen, both giving a mean value equal to 2.5 hours for the interruption time, like in base case.

In this example this is achieved by a lognormal distribution with parameters $\mu = 0.25$ and $\sigma = 1.2$ and a Gamma distribution with parameters $\rho = 0.5$ and $\lambda = 0.2$. Fig. 7.23 shows the results for interruption time.

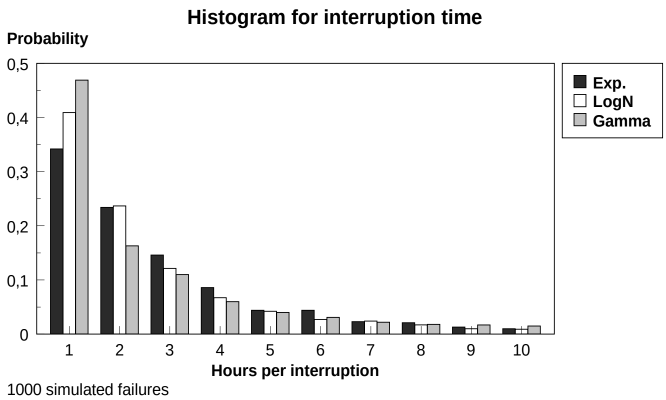


Fig. 7.23 Histogram for interruption time with different distributions of r.

Results for different statistics compared to the base case where repair time is exponentially distributed are given in Table 7.18. Similar results for interruption cost are given in Table 7.19.

Table 7.18 Dispersion in **interruption time** (hours per interruption) with lognormal- and Gamma distribution.

Distribution	Mean	Standard dev.	50 percentile	90 percentile
Exponential	2.5	2.9	1.7	5.8
Lognormal	2.5	3.9	1.2	6.0
Gamma	2.5	3.5	1.1	7.1

Table 7.19 Dispersion in **cost per interruption** (NOK per interruption) with lognormal- and Gamma distribution for repair time.

Distribution	Mean	Standard dev.	50 percentile	90 percentile
Exponential	5889	6489	4000	12397
Lognormal	6153	9018	3092	14378
Gamma	6318	9234	2872	15414

The results can be compared to base case with exponentially distributed repair time in Table 7.11 and Figs. 7.8 and 7.11. We get practically the same mean values from the simulations, while the 50 percentile is lower and the 90 percentile is higher with both a lognormal- and Gamma distributed repair time. These results indicate that there is a larger dispersion than in the base case. This impression is confirmed by a visual inspection of Fig. 7.23.

There is a higher probability of getting both low and very high values of r. Thus both the chosen lognormal- and Gamma model give a larger dispersion in the individual repair times. These distributions are steeper and have a longer tail than the exponential distribution. Tables 7.18 and 7.19 show that the lognormal- and Gamma model give significantly higher standard deviations than the mean values, while for an exponential model the standard deviation will be approximately equal to the mean.

The above results are taken from a simulation of 1000 failures for each type of distribution. The different values in the tables do not give an exact estimate of the different statistics. The results are suitable for illustration of what kind of influence stochastic variations might have. Depending on the choice of parameters in the probability distributions, the dispersions in the individual interruption times or interruption costs will increase or decrease, compared to base case.

The shape of the lognormal, Gamma and exponential distributions used in this example are quite equal (Fig. 7.23). What happens with EIC when both the shape of the probability distribution for r and the cost function change (cfr. Section 7.3.3)? To check the influence of the distribution of interruption time on EIC for different cost functions, simulations are made for an exponential distribution and two different lognormal distributions. All three distributions give approximately 2.5 hours average interruption time. The variances are approx. 6, 0.05 and 1.5 respectively.

Annual interruption costs are calculated for $\lambda = 1$, $P_{max} = 100$ kW and the reference cost, assuming no time variations. The simulations are performed for both industrial and commercial cost functions from Fig. 7.2 and using the Swedish commercial cost function from Fig. 2.2. This cost function is less linear than the Norwegian one. The influence of the nonlinearity is shown by calculating the mean of interruption time and interruption cost for the two lognormal distributions relatively to the exponential. The relative factors are shown in Table 7.20 (approximate values).

Table 7.20 Results relative to using an exponential distribution. Approximate values. $E(r) = 2.5$, $P = 100$ kW, $\lambda = 1$. Different CDF's.

Distribution	Lognormal I		Lognormal II	
CDF	$E(r)/E(r)_{exp}$	EIC/EIC_{exp}	$E(r)/E(r)_{exp}$	EIC/EIC_{exp}
Industrial, Norway (Fig. 7.2)	1.0	1.00	1.0	1.00
Commercial, Norway (Fig. 7.2)	1.0	0.94	1.0	0.97
Commercial, Sweden (Fig. 2.2)	1.0	0.94	1.0	0.95

The factors in Table 7.20 are taken as average values for several runs. They indicate that the nonlinearity of the cost function has an influence on EIC when the shape of the repair time distribution changes. This is due to the dependency between the specific cost and the duration.

As expected the relation between the mean interruption times is approx. equal to 1.0. The industrial cost function is practically linear, thus giving no change in EIC for different distributions. For the two commercial cost functions EIC is highest for the exponential distribution due to the large dispersion in interruption time. Similarly EIC is lowest for the first lognormal distribution due to the small dispersion. The difference between the exponential distribution and the second lognormal is a bit smaller. It is difficult to tell whether there are differences in the results for the two commercial cost functions, but the results indicate that large dispersions in interruption time may influence the annual costs when the cost function is nonlinear. This is in accordance with the results reported in [47, 54].

7.5.2.2 Load dispersion

The load dispersion in base case is described by a standard deviation of 10 %. The influence of this dispersion is illustrated for power not supplied and annual interruption cost by setting $\sigma_P \approx 0$ % and $\sigma_P = 20$ %. EPNS and EIC with a 95 % confidence interval and the 50- and 90 percentiles are calculated. The results are given in Table 7.21. Deviations for EPNS and EIC for these runs compared to the base case expectations in section 7.2 are within ± 5 % from the analytical expectations.

Table 7.21 PNS and IC with a standard deviation of 0% and 20 % for the load, base case. The relative values are given in percentage of the expectation.

$\sigma_P = 0$ %	Expectation	50 percentile	90 percentile	95 % conf. int.
PNS	47	42 (- 9 %)	65 (+ 40 %)	[46, 48] ± 2 %
IC	6128	3865 (- 37 %)	14079 (+ 128 %)	[5721, 6534] ± 7 %
$\sigma_P = 20$ %				
PNS	46	44 (- 5 %)	73 (+ 58 %)	[45, 48] ± 2 %
IC	6173	3886 (- 37 %)	14133 (+ 129 %)	[5707, 6639] ± 7 %

From the figures in Table 7.21 we see that the dispersion in load has little practical influence on these statistics. For PNS, the confidence interval is about ± 2 % from the expectation for both standard deviations. For IC, the confidence interval is about ± 7 %. The percentiles for IC are unchanged relative to the expectation, while both percentiles for PNS increase with a higher standard deviation. This is also illustrated by the histogram for PNS in Fig. 7.24.

As expected, the change in dispersion leads to different forms of the histogram for PNS. The form of the histogram for IC is unchanged.

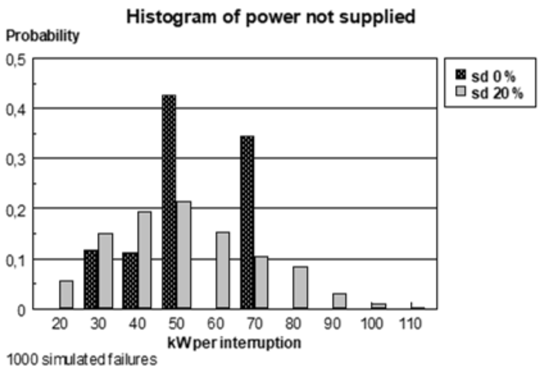


Fig. 7.24 Histogram for PNS with σ_P = 0 % and σ_P = 20 %.

7.5.2.3 Dispersion in specific interruption cost

Normal distribution

The stochastic variation in the specific interruption cost is described in the base case by a Normal distribution with mean $c_{h,d,m}$ and σ_c = 20 %. The standard deviation is set to 0 % and 50 % to illustrate the influence of the dispersion in specific cost. Similar statistics as in the previous section are calculated for IC and the specific cost per interruption c(r). The results are given in Table 7.22. The deviations in the expectations from Section 7.2 are within ± 5 %.

Table 7.22 IC and c(r) with a standard deviation in c(r) of 0 % and 50 %, base case.

σ_c = 0 %	Expectation	50 percentile	90 percentile	95 % conf. int.
IC	5834	4101 (- 30 %)	13072 (+ 124 %)	[5438, 6231] ± 7 %
c(r)	134	87 (- 35 %)	300 (+ 123 %)	[125, 144] ± 7 %
σ_c = 50 %				
IC	5978	3449 (- 42 %)	14060 (+ 135 %)	[5484, 6473] ± 8 %
c(r)	144	76 (- 48 %)	345 (+ 139 %)	[131, 158] ± 9 %

With a standard deviation of 50 %, the percentiles for c(r) deviate more from the expectation than with zero standard deviation, and the confidence interval is increased relative to the expectation. This is as expected and in accordance with the results for PNS with increased load dispersion. For IC we get the same tendency in the dispersion, i.e. larger confidence interval and percentiles that deviate more from the expectation, with increasing standard deviation for c(r). The form of the histogram for both IC and c(r) remains practically unchanged. These are still dominated by the interruption time. Fig. 7.25 gives the histogram for IC.

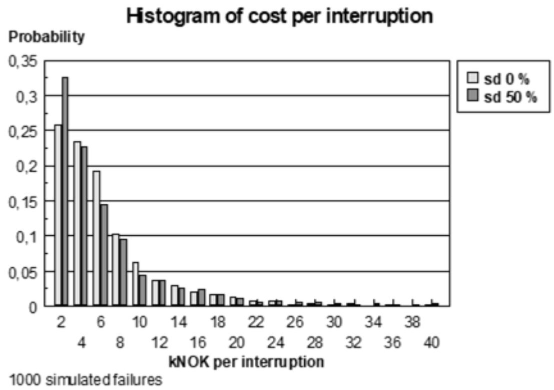


Fig. 7.25 Histogram for IC, with σ_c = 0 % and σ_c = 50 %.

Discrete probability distribution

So far the stochastic variation in specific cost has been described by the Normal distribution. In practice the specific cost is probably not Normally distributed as discussed in Chapters 2 and 4. It seems that the cost distribution is highly skewed, and that a large part of the respondents in the surveys have zero cost, at least for the shorter interruptions. The Normal distribution has been chosen in lack of any established probability distribution and due to its simplicity. From the Norwegian survey a typical histogram of the reported costs for the Industry sector is similar to the one presented in Fig. 7.26.

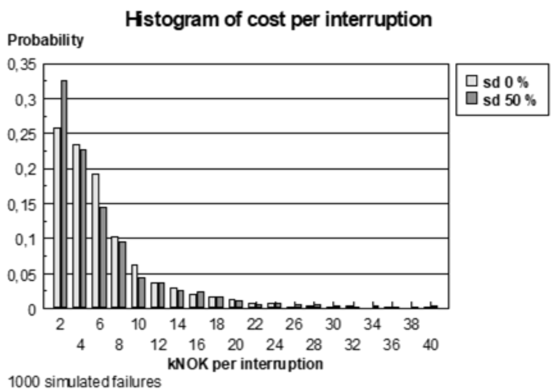


Fig. 7.26 Histogram of specific cost for industrial sector, example.

This histogram is chosen as a discrete probability distribution for the specific interruption cost, giving about the same expectation for the specific cost ($c_{h,d,m}$) as in base case. There is a large probability of having zero cost, and a smaller, but large probability of having a cost between zero and 1 expectation. The distribution has a long tail, with some probability of having a cost of up to 18 times the expectation. This distribution is assumed to be equal for all interruption times.

Several runs with 1000 simulated failures are made, showing that the results are not that stable as with a Normal distribution. This indicates that the number of simulations should be increased. Results for a run giving EIC within ± 5 % are given in Table 7.23.

Table 7.23 Results for IC and c(r) with a discrete probability distribution for c(r).

Index	Expectation	50 percentile	90 percentile	95 % conf. int.
IC	6041	0 (- 100 %)	13712 (+ 127 %)	[4915, 7168] ± 19 %
c(r)	143	0 (- 100 %)	355 (+ 148 %)	[117, 169] ± 18 %

In this case we get a 50 percentile equal to zero for both the annual cost and the specific cost per interruption, while the 90 percentile are in the same order as in the case with σ_P = 50 %. The confidence intervals are much wider than in the cases with the Normal distribution. The histogram for IC is given in Fig. 7.27.

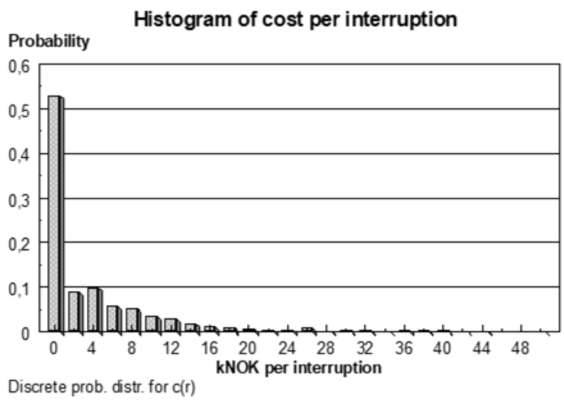


Fig. 7.27 Histogram for annual interruption cost with a discrete prob. distribution for c(r).

From the figure we see that in more than 50 % of the interruptions the cost will be zero, cfr. the 50 percentile. The form of the histogram is changed with the large portion of zero costs. IC is in this case dominated by both the distribution of interruption time and the specific cost.

The data collected for the studied durations in customer surveys, such as 1 min., 1 hour, 4 hours and 8 hours, might have different distributions. Since these probabilities cannot be described by any known parametric distribution, it is a problem to find the cost at intermediate durations. This problem is dealt with in [15, 16, 17], where a procedure is developed to convert the data to a Normal distribution. Based on the relationship between the studied durations, a set of parameters associated with an intermediate duration can be determined. Interpolations between the studied durations will also be normally distributed, according to [17].

With this kind of procedure it is possible to determine the specific cost per interruption randomly by drawings from a probability distribution for any interruption duration, based on those data directly surveyed.

7.6 Radial systems

So far in this chapter we have only considered a single network component supplying the delivery point. In this section the calculation methods are demonstrated for a two-component radial system, with an overhead line and a cable.

7.6.1 Example data

The delivery point in this example is the same as in Fig. 7.1. The network and the basic data are shown in Fig. 7.28. Time variation for the load and the specific cost is equal to the base case, while the time variations for overhead line and cable from Section 7.5.1 are chosen (given in Appendix 6). The stochastic variations for P and c are still given by a Normal distribution with parameters $P_{h,d,m}$ and σ_P = 10 %, and $c_{h,d,m}(r)$ and σ_c = 20 % respectively, as in base case.

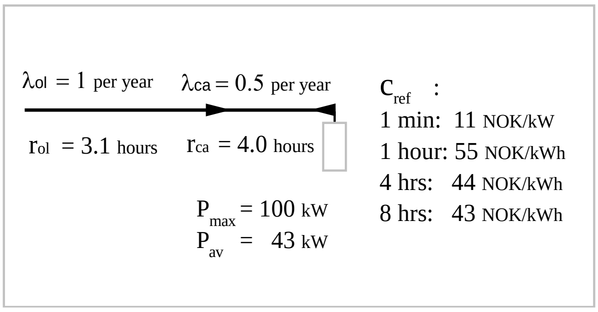


Fig. 7.28 Two-component case, radial system.

7.6.2 Results for two components

The results from the analytical expectation method are given in Table 7.24 for the correction factors and in Table 7.25 for the expectation values. The reliability indices for the delivery point are calculated according to the procedure for radial systems described in Section 6.2.3.

Table 7.24 Correction factors for overhead line and cable serving base case delivery point.

Component	$k_{\lambda r}$	$k_{\lambda P}$	$k_{\lambda Pr}$	$k_{\lambda Prc}$	b
Overhead line	0.943	0.463	0.434	0.491	1.133
Cable	1.011	0.472	0.421	0.484	1.148

Table 7.25 Expectation values for reliability indices, base case delivery point.

Component	λ	U	r	EPNS	EENS	EIC
Overhead line	1	3.1	3.1	46	143	7258
Cable	0.5	2.0	4.0	24	84	4257
Sum	1.5	5.1	3.4	79	227	11515

In the long run the delivery point will experience 1.5 interruptions per year with a total of 5.1 hours interruption time per year and a total annual interruption cost of NOK 11515. IEAR for this supply situation is EIC/EENS = 50.7 NOK/kWh. A comparison with the traditional analytical method is given in Table 7.26.

Table 7.26 Comparison of expectation values.

Method	U	EPNS	EENS	EIC
Expectation method	5.1	70	227	11515
Traditional[1)]	5.3	65	228	12167
Deviation (%)	+ 4	- 7	+ 0	+ 6

EIC[1)] calculated with the traditional method is based on the annual average cost c_{Wav}, thus leading to a small overestimation of the cost. If however the reference cost c_{Wref} is used, EIC[2)] becomes NOK 10139, which represents an underestimation of 12 %. These results are in accordance with the results for the base case in section 7.2, where EPNS is also underestimated by the traditional method. Using the specific cost at reference time underestimates the annual interruption costs.

In the calculation of EIC, $EIC^{1)}$ and $EIC^{2)}$ the specific cost for r_{av} for overhead line and cable respectively, is applied, i.e., the contribution to the annual cost is calculated for each component separately according to Eq. (6.9).

The average interruption time for the delivery point is from Table 7.25 equal to 3.4 hours. The specific cost at reference time for 3.4 hours is c_{res} = CDF(3.4) = 44.6 NOK/kWh. The IEAR indices calculated by the three methods are:

IEAR = 50.7 NOK/kWh = $1.138c_{res}$
$IEAR^{1)}$ = 53.4 NOK/kWh = $1.2c_{res}$
$IEAR^{2)}$ = 44.5 NOK/kWh $\approx$ c_{res}.

These figures are in accordance with the base case results in Section 7.2. $IEAR^{1)}$ from the traditional method equals the annual average of the specific cost, while $IEAR^{2)}$ equals the reference cost and IEAR a factor ‘b’ times the reference cost (including the time dependent correlation). The b-factor is in this case in between the two b-factors in Table 7.24, resulting from one failure on the overhead line and 0.5 failure on the cable.

Expectation values calculated by a Monte Carlo simulation of 1000 failures on each of the components, representing 1000 years for the overhead line and 2000 years for the cable, are given in Table 7.27.

Table 7.27 Expectation values calculated by the analytical method and by Monte Carlo simulation.

Method	U	EPNS	EENS	EIC	IEAR
Analytical	5.1	70	227	11515	50.7
Monte Carlo	5.2	69	228	11638	50.9
Deviation (%)	+ 1	- 1	+ 0	+ 1	+ 0

The histogram of annual cost is given in Fig. 7.29. The contributions from each of the components are shown in the figure. The annual cost is here determined by the multiplication of the simulated cost per interruption and the annual average failure rate. This represents a simplification of the problem due to the decoupling of failures per year and the distribution of failures within a year. In the prototype, the failures per year are held constant and equal to the average annual failure rate. The Monte Carlo simulation should in principle include a random number of failures from year to year as described in section 6.3.

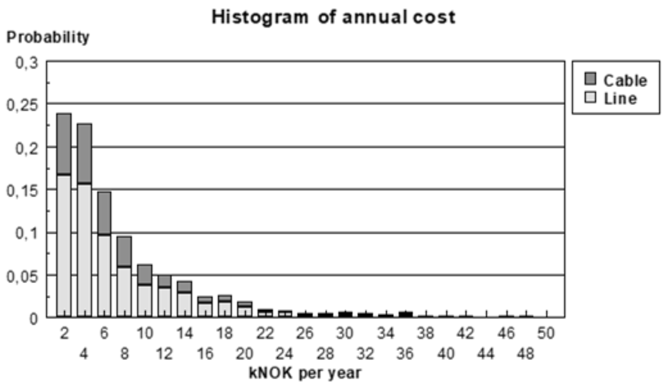


Fig. 7.29 Histogram of annual cost, 1000 simulated failures per component.

The 50- and 90 percentiles and a 95 % confidence interval for EIC are calculated with the relative deviation from the expectation. The relative deviations from EIC are in the same order as for the single component base case (Tables 7.9 and 7.11):

50 percentile: NOK 6596 (- 43 %)
90 percentile: NOK 25863 (+122 %)
95 % conf. int.: NOK [10795, 12481] (± 7 %)

Uncertainties in the input variables are in addition handled by a fuzzy description, using the procedure in Section 6.4. Trapezoidal membership functions are chosen with corners determined by the relative figures from Table 7.12 (base case). Expectations (crisp values) and membership functions are calculated as in Section 7.4 both with a crisp and fuzzy failure rate (λ). According to the radial model the contributions from the overhead line and cable are calculated separately, while the resulting fuzzy reliability indices are determined by the summation of fuzzy variables. The crisp reliability indices are given in Table 7.28, the corners of the membership functions in Table 7.29 and the membership functions for EENS and EIC in Fig. 7.30.

Table 7.28 Crisp reliability indices for the two-component radial system.

Reliability index	With crisp λ	With fuzzy λ
U, hours per year	5.1 (0 %)	5.3 (+ 4 %)
EPNS, kW per year	70 (0 %)	71 (+ 1 %)
EENS, kWh per year	230 (+ 1 %)	241 (+ 6 %)
EIC, NOK per year	11802 (+ 3 %)	13069 (+ 14 %)
IEAR, NOK/kWh	51.4 (+ 2 %)	54.2 (+ 7 %)

Table 7.29 Corners of membership functions for the two-component radial system.

Reliability index	With crisp λ				With fuzzy λ			
	a_1	a_2	a_3	a_4	a_1	a_2	a_3	a_4
U, hours per year	2.1	4.1	6.2	8.2	1.0	3.3	7.4	12.3
PNS, kW per year	63	66	73	77	32	53	88	115
ENS, kWh per year	82	173	287	400	41	138	344	600
IC, NOK per year	2591	5469	18136	22166	1295	4376	21763	33248

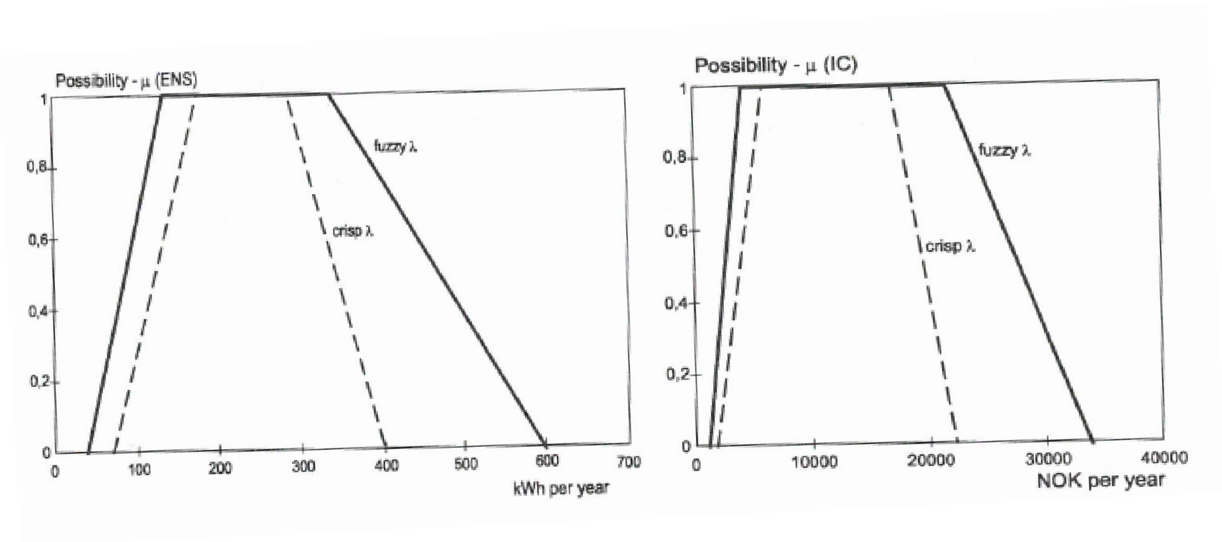


Fig. 7.30 Membership functions for ENS and IC for the radial system.

As for the base case the chosen fuzzy input variables give wide membership functions. The deviations in the crisp expectation values are equal to the base case (Table 7.13): small with crisp λ and somewhat larger with fuzzy λ. The deviations increase with the number of non-linear combinations, and thus the crisp EIC (multiplication of 3 fuzzy variables) has the largest deviation from the analytical expectation.

7.7 Meshed systems

The calculation method for meshed systems described in Section 6.2.4 and the Monte Carlo simulation method are illustrated for a simple system with two parallel lines supplying a bulk delivery point. No local generation is considered.

7.7.1 Basic data

Data for the two lines A and B and for the delivery point are given in Fig. 7.31. The maximum and average load is P_{max} = 979 MW and P_{av} = 566 MW respectively. There are three outage combinations, two single outages and one dependent overlapping outage:

- Line A (SAC = 500 MW)
- Line B (SAC = 500 MW)
- Line A&B (SAC = 0 MW).

System Available Capacity (SAC) for the three combinations given in brackets are considered constants. When both lines are in, SAC = 1000 MW. According to Chapter 3, interruption occurs when SAC < P. The amount of load disconnected equals P - SAC (Eq. (3.4)).

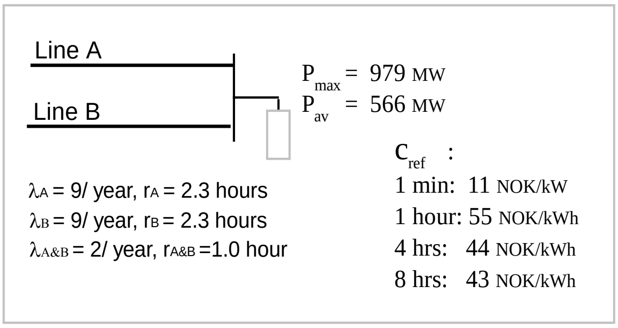


Fig. 7.31 Parallel supply of bulk delivery point.

Individual time variations are represented for each outage combination, but only monthly variation in failures and repair time, and monthly-, weekly and daily variation in load is considered. No time variation in specific cost is included. The time variation data are given in Appendix 6.

Repair time is considered to be exponentially distributed, while no stochastic variations are considered for the load and specific cost.

The cost function for industrial sector is chosen in this case as well even if it is a rather unrealistic cost for a bulk delivery point or a local area. The example is included to illustrate the methods on a meshed system. The methods are demonstrated on a more realistic case in Chapter 8.

7.7.2 Results for the parallel lines

Reliability indices for the delivery point are calculated both analytically and by the Monte Carlo method.

According to the procedure in Section 6.2.4 the analytical calculation is performed using the conditional probabilities (q_λ-factors) of having failures in particular months, weekdays and hours. The contribution from each of the 24·7·12 = 2016 time points is calculated, and for each time point $r_{h,d,m}$, $P_{h,d,m}$ and $c_{h,d,m}$ are determined and combined with the number of failures $\lambda_{h,d,m}$ to yield the contributions to different indices. Finally the 2016 contributions are summed up giving the annual reliability indices.

Expectation values found analytically and by Monte Carlo simulation are given in Table 7.30. 1000 failures are simulated for each of the single outages and 500 failures are simulated for the dependent double outage. The deviations from the analytical expectations are given in brackets for the Monte Carlo results.

Table 7.30 Reliability indices for bulk delivery point, two parallel lines.

Reliability index	Analytical	Monte Carlo	
λ, numbers per year	12.4	12.4	(0 %)
U, hours per year	25.4	27.8	(+9 %)
r, hours per interruption	2.0	2.2	(+10 %)
EPNS, MW per year	3264	3257	(0 %)
EENS, MWh per year	5385	5546	(+4 %)
EIC, kNOK per year	265817	269692	(+2 %)
IEAR, NOK/kWh	49.4	47.3	(-4 %)

The contribution from each outage combination is given in Table 7.31 for the analytical method.

Table 7.31 Contribution to reliability indices from the different outage combinations.

Outage	λ	U	r	EPNS	EENS	EIC
Line A	5.2	11.7	2.3	1054	2114	101107
Line B	5.2	11.7	2.3	1054	2114	101107
Line A&B	2.0	2.0	1.0	1156	1156	63603
Sum	12.4	25.4	2.0	3264	5384	265817

The dependent overlapping outage contributes about 8 % to the annual interruption time, but almost 22 % to EENS and 24 % to EIC, due to SAC being zero when both lines are out.

In this example the reference cost is used throughout the calculations since no time variation in specific cost is considered. If instead the average annual cost is used, the results for EIC will be increased by 20 % ($c_{Wav} = 1.2c_{Wref}$ for Industry).

The resulting indices λ, U and r for the delivery point are calculated according to Eqs. (3.2 - 3.3).

8. Applications in transmission and distribution systems

Applications of the methods for estimation of reliability indices and annual costs are illustrated in this chapter for delivery points in transmission and distribution systems. Typical local and global decision problems are described. A general delivery point description of interruption costs and loads is included. The chapter gives an example from the transmission system including a comparison with a different model for meshed systems. An example of cost-benefit analyses is included for the distribution system case.

8.1 Decision problems

Different decision problems can be stated as a basis for the Value Based Reliability Planning (VBRP, cfr. Chapters 1 and 5). The description and calculation of reliability worth will be different depending on the decision problem. Here we concentrate on two main types of problems:

- Local decisions
- Global decisions.

The target in any of these types of decision problems is to determine the total aggregate interruption costs (the reliability worth) for a particular system alternative. The total aggregate interruption costs are composed by the annual interruption costs for the different customers in the area affected by the reliability measures. The assessment of the customers' annual interruption costs is described in the previous chapters in relation to the simple system in Fig. 8.1.

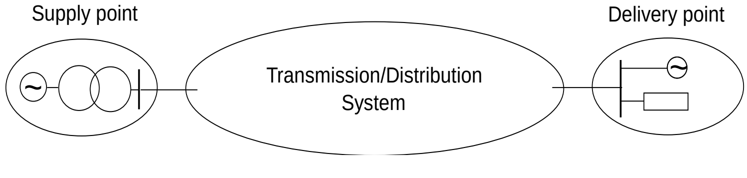


Fig. 8.1 System model for estimation of annual interruption costs.

In Fig. 8.1 the power system supplying the load point is represented by one compact element containing all potential network components between the load and the supply point. The load point or delivery point represents one single customer or a mixture of customers in a supply area. A description of the interruption costs and loads in the delivery point is given in Section 8.2.

8.1.1 Local decisions

Local VBRP decisions typically deal with single reliability measures with the intention of changing the reliability level. This represents a *short term* planning problem, typically cost-benefit analyses of reliability measures year by year. It is usually neglected that measures taken to improve or decrease the reliability level may also affect the electrical losses. Examples of such reliability measures are given in the list below.

EXAMPLES OF RELIABILITY MEASURES
☞ Component related - Choice of material - Choice of protection relays - Installation (or removal) of breakers or disconnectors ☞ Customer related - Reserve unit - UPS - Alternative energy supply ☞ Utility related - Change number of skilled employees on guard - Change restoration procedures - Training of personnel - Mobile reserve cable/transformer - Spare part storage ☞ Control - Remote control of breakers and disconnectors - Automatic reclosure - Installation of fault indicators ☞ Maintenance planning - Change maintenance level - Change maintenance routines - Live line working

Local decisions typically affect a single customer, a single delivery point with several customers connected or a few delivery points. This is a typical distribution system problem, representing a top-down approach where the utility deals with a limited number of customers (or delivery points), and there will be little or no aggregation of customer costs.

Typical local decision problems are:

- Replacing overhead line by underground cable?
- Building parallel lines or establish local reserve as alternative supply?

8.1.2 Global decisions

In a global VBRP decision problem, the objective is typically to perform *medium*- or *long-term* planning affecting the whole system or part of the system. Medium- and long- term planning are conducted for a time horizon of typically 5-10 or 10-20 years, reliability cost/worth being one of several considerations.

System planning is for instance a long- term planning problem which usually affects the network structure, and new load points may be introduced during the period of analysis. The future loads, both load increase and the new loads, are uncertain factors. These kinds of problems are not plain reliability optimization problems because the electrical losses and thereby the costs of losses also will be influenced.

Similarly planning of the tariff structure represents a medium- or long- term planning problem, involving several kinds of technical and economic considerations and represents as such a global decision problem.

Examples of planning problems are given below.

EXAMPLES OF PLANNING PROBLEMS
☞ System planning - New lines/cables - New transformer stations - New reserve connections - Protection and load curtailment philosophies ☞ Operation planning - Optimization of operation scheme - Planning of maintenance activities ☞ Tariffs - General tariffs (quality based) - Repayment for energy not supplied

Global decision problems affect a large part of or the whole supply area and therefore, in general, several delivery points. Determination of the interruption costs represents a bottom-up approach by aggregating the costs for the various delivery points, each supplying one or more customers. The higher the system level, the more aggregated the cost description will be.

8.2 Delivery point description

According to Chapter 3, a delivery point is a busbar (point) where electric power is delivered to consumers, between network owners or the interface point between different voltage levels in a utility's own network. Thus, a single delivery point can represent either a single customer, a few customers or a local area. A bulk supply point represents a delivery point at the most aggregated level. The description of specific interruption costs and loads may be different for the different types of delivery points.

8.2.1 Interruption costs

8.2.1.1 Aggregation of specific interruption costs

The cost model for a single customer is given in the previous chapters. For a group of customers a common way to determine the resulting specific cost is to weigh the individual customer groups' specific costs with their portions of the energy consumption (or load) in the delivery point. This is discussed in Sections 2.3.1 and 6.5. An example of a resulting Customer Damage Function is given in Section 8.3 for the Norwegian energy consumption. The resulting specific cost for a group of loads (or customers) for a given interruption time can be calculated according to Eq. (6.35), giving a resulting CDF:

$$c_{res,ref} = \sum_{i=1}^{s} c_{i,ref}\, w_i \tag{8.1}$$

where:

s = number of customer- (or load-) groups connected to the delivery point
w_i = weight for customer- (or load-) group no. i
$c_{i,\,ref}$ = reference cost for group no. i.

This equation gives the resulting specific cost at reference time for a given interruption duration.

8.2.1.2 Time variation in aggregated specific cost

We have seen that the time variation in specific costs is different for the various customer groups. This may affect the time dependent correlation and the correction factors used to calculate the annual interruption costs EIC (for a radial system). The general cost formulation for a delivery point supplying several customer groups is given in Eq. (6.36), when a radial model is considered:

$$EIC = P_{\max} \sum_{j=1}^{J} \lambda_j \Big(\sum_{i=1}^{s} c_{i,ref}\big(r_j \big) w_i \, k^{*}_{\lambda Prc_{ij}} \Big) \tag{8.2}$$

The variables are explained in Ch. 6. Eq. (8.2) is a modification of Eq. (6.36) since the correction factor $k^{*}_{\lambda Prcij}$ depends on both customer group ('i') and type of component ('j') in the most detailed version.

This formulation requires a detailed calculation of the contribution to the annual costs from each customer group. Since the specific cost for each customer group is a function of interruption time, the resulting cost should be calculated on the basis of the individual costs for each interruption. An approximation to this formulation can be to use the resulting (composite) CDF, which gives the reference cost as a function of duration, together with a resulting correction factor independent of component type and customer type:

$$\begin{aligned} EIC &= P_{\max} \, k_{\lambda Prc,res} \sum_{j=1}^{J} \lambda_j \Big(\sum_{i=1}^{s} c_{i,ref}\big(r_j \big) w_i \Big) \\ &= P_{\max} \, k_{\lambda Prc,res} \sum_{j=1}^{J} \lambda_j \, c_{res,ref}(r_j) \end{aligned} \tag{8.3}$$

To determine the resulting factor $k_{\lambda Prc,\, res}$ we need a time variation for the resulting cost. This can be found as shown in the following.

The aggregated specific cost for an interruption occurring at time (h, d, m) can be expressed by:

$$c_{res(h,d,m)} = \sum_{i} c_{i,ref} \, w_i \, k_{c(h,d,m),i} \tag{8.4}$$

The $k_{c(h,d,m),i}$-factor represents the relative time variation in the specific cost for each customer group. The relative time variation in the resulting specific cost is then given by the factor $k_{c(h,d,m),res}$:

$$k_{c(h,d,m),res} = \frac{c_{res(h,d,m)}}{c_{res,ref}} = \frac{\sum_{i} c_{i,ref} \, w_i \, k_{c(h,d,m),i}}{\sum_{i} c_{i,ref} \, w_i} \tag{8.5}$$

This factor can be determined by three separate factors describing the relative monthly-, weekly- and daily variation in the resulting specific cost. The separate factors can be calculated according to Eqs. (8.5) and (5.10), using the individual reference costs and corresponding individual cost factors.

The resulting average cost variation for the Norwegian energy consumption is calculated and given in Fig. 8.2 and in tables in Appendix 7. The specific reference costs from the Norwegian survey and the consumption weights are given in Section 8.3. Fig. 8.2 gives the relative cost variation based on the individual CDF’s for 4 hours. The figure gives the relative variation in both specific cost and absolute cost per interruption. It should be noted here that the resulting cost variation in Fig. 8.2 is based on the two load types and the example data in Ch. 4, and no time variation is assumed for the agriculture and residential sectors.

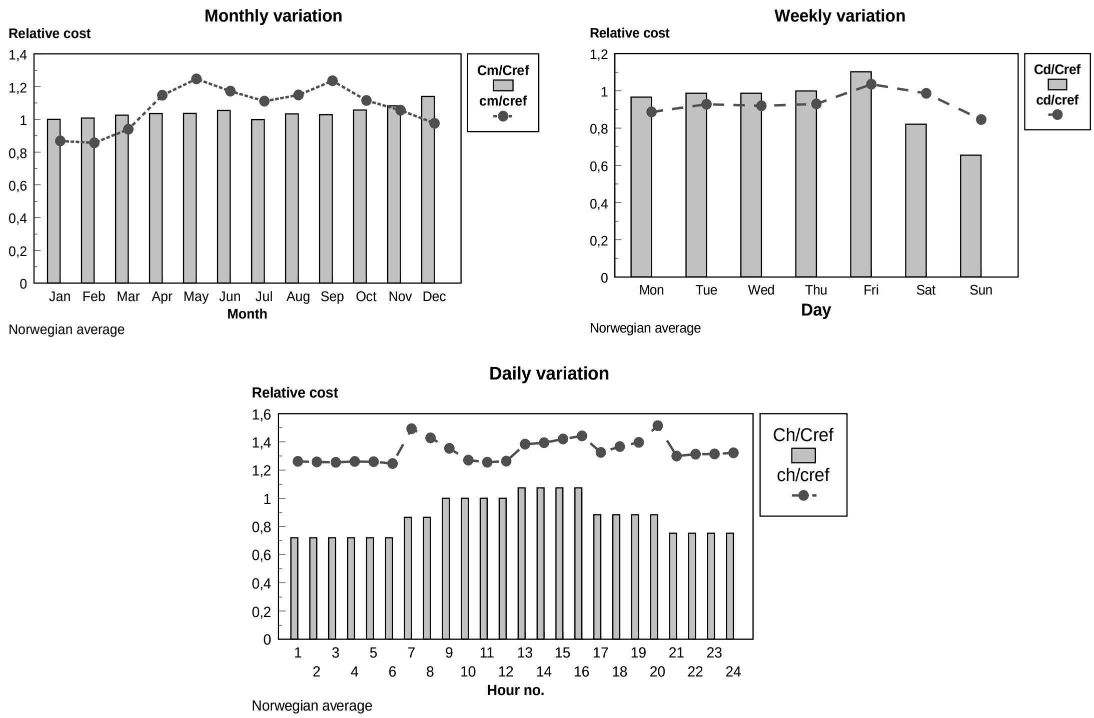


Fig. 8.2 Resulting relative cost variation for the Norwegian energy consumption (examples).

8.2.2 Loads

8.2.2.1 Classification of loads

The cost description in the previous section is based on a total interruption of loads upon occurrence of interruption. This assumption is not always true in the transmission system. From Chapter 3 we have found that an interruption occurs when the System Available Capacity (SAC) is less than the load demand, after the occurrence of a contingency such as a double line outage. The load interrupted is the difference between the load demand and SAC

(Eq. (3.4)).

If all the loads connected to the delivery point are considered equally important, a resulting specific interruption cost and relative cost variation can be applied according to the description in the previous section. In that case the cost description and the aggregation of specific costs for different loads or customers will be the same for a bulk delivery point as for a distribution delivery point. Eqs. (8.2 - 8.3) are however applicable for radial systems only, with the use of correction factors to calculate EIC.

Sometimes a selective disconnection of loads is possible, starting with the interruptible load, the less critical load and finally the critical load. Such a procedure will require a cost description for each load type. Since this is a topic particularly at the transmission level, the delivery point load will usually represent an aggregation of several consumers. Thus an aggregated cost description (for the specific cost) like in the previous section can be used for each class of loads.

A selective load disconnection procedure is not included in the prototyped methods developed in this work. This kind of equipment is in use in some countries, but is not yet installed to any extent in Norway.

8.2.2.2 Time variation in loads

The radial model for calculation of EIC makes use of correction factors that are calculated on the basis of general time variation in failures, repair time and loads in addition to the specific cost. There are usually no load measurements in the delivery points in distribution systems. The relative time variation will instead be established for typical load types on the basis of comprehensive measurements on different loads of the same type. These typical load profiles can be used together with P_{max} which is generally known for the delivery points, for the local climate (average temperatures). The relative time variation used to determine the load at a particular time $P_{h,d,m}$ as described in Chapter 5, is based on such typical load profiles. With the use of the general profiles for different types of load, the correction factors may have to be modified according to a different utilization time in the delivery point from the one inherent in the relative profiles (see Section 7.2.1).

In transmission systems, the load situation is monitored continuously, and an hourly load curve is usually available (8760 values) in addition to information on the maximum load. To apply the models described in Chapter 6 that handle the time variation in the different variables, the load must be represented by the relative monthly-, weekly- and daily variation like for radial systems. As mentioned earlier, the methods can be extended to handle 8760 hourly values, but this would require an extensive data base for each variable. The hourly load curve will for the time being have to be transformed to relative monthly-, weekly- and daily load profiles.

8.3 Transmission system - case

Section 7.7 showed how the method handling time variation can be applied to meshed systems, using a simple network with two lines. In this section the method is applied to a real case from the Norwegian main grid. This is an example of the application of the method for transmission systems. The main purpose of the example is to illustrate the use of the methods for estimation of annual interruption costs, and the case is simplified as explained later. The case is provided by The Norwegian Power Grid Company (Statnett). Statnett is responsible for planning, operation and maintenance of the main grid (420 kV, 300 kV and partly 132 kV).

The supply to a local area in the south-western part of Norway is studied. The local area, covering the city Stavanger and its surroundings, is considered as a delivery point. A description of the case with data and results is given in the next sections, and a comparison with results from the Monte Carlo model LARA is given in Section 8.3.3.

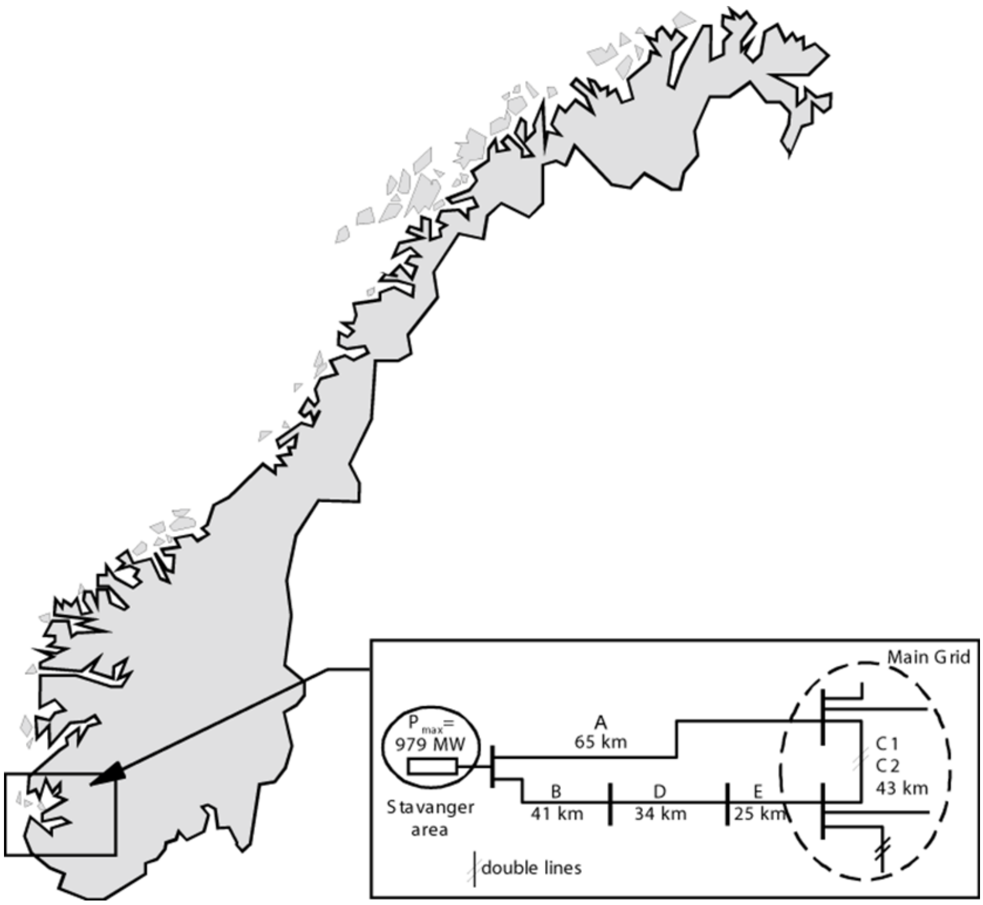


Fig. 8.3 Single line diagram of transmission system supplying the Stavanger area.

8.3.1 Description of case and data

The network is given in the single line diagram in Fig. 8.3. The figure shows only the most important lines supplying this area. The approximate line lengths are given in the figure. There are a few small generators within the area, providing some local generation, but these are not considered although they provide about 300 MW. The maximum and average load in the area are P_{max} = 979 MW and P_{av} = 566 MW respectively (load level year 2000). The voltage level is 300 kV.

From contingency evaluation it is found that there are 5 outage events giving a significant reduction in the System Available Capacity (SAC). These are given in Table 8.1 with their resulting failure rates and average repair times. The same time variation in failures and repair time for all outage combinations is assumed.

One dependent double outage and two independent overlapping outages give an SAC equal to zero, leading to a total interruption of loads in the area. Other possible single outages or outage combinations (such as generator and line) are not considered since they have very little influence on the total results. These are contingencies with very low probability (such as A+E) and/or giving only small reductions in SAC. Scheduled maintenance (and overlap with failures) is not considered. It is shown from other studies of the area that overlap between failures and maintenance may be the main contributor to EENS and EIC and as such should be included in a real case [68].

Table 8.1 Failure statistics and SAC for different outage events, transmission case.
SAC = 1000 MW with all lines available.
'&' = dependent outage, '+' = independent overlapping outage

Outage*) event	Line outages	SAC (MW)	Failure rate (no. per year)	Repair time (hours per failure)
A & B	A and B, dependent	0	0.167	0.157
C1 & C2	C1 and C2, dependent	616	0.583	0.252
A + B	A and B, overlapping	0	0.0025	0.170
A + D	A and D, overlapping	0	0.00019	0.146
A	A, single	848	2	0.221

*) A + E is not included since the failure rate ≈ 0.

The hourly load curve (8760) values are transformed to three different profiles, giving the relative monthly-, weekly- and daily load variation. These are shown in Fig. 8.4.

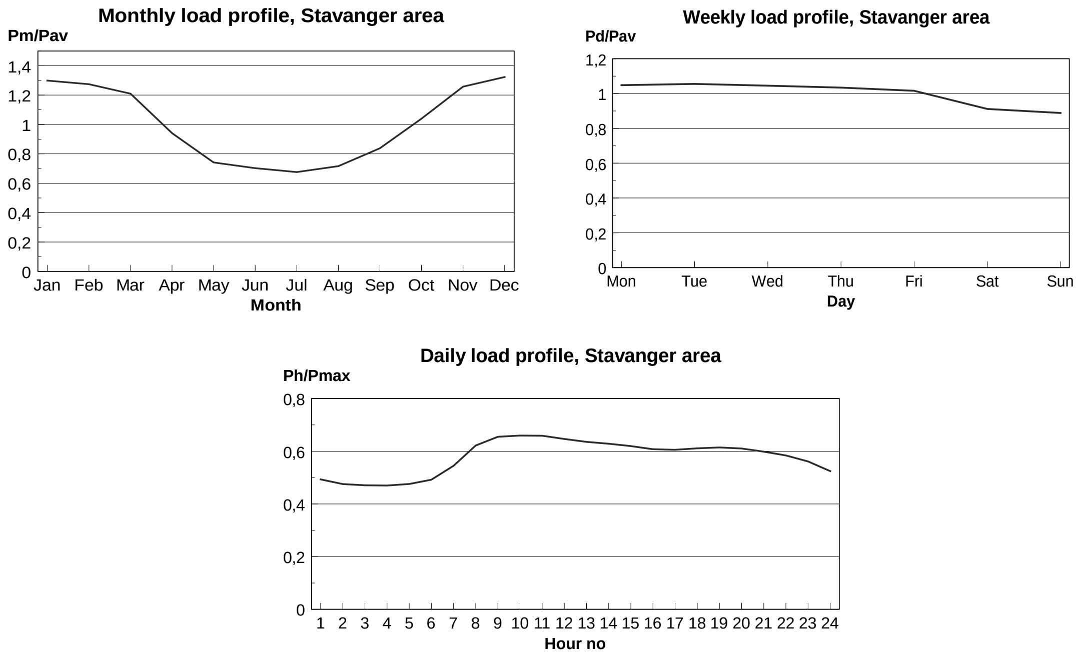


Fig. 8.4 Monthly-, weekly- and daily load profiles for the local area.

The delivery point load is assumed to be composed by 4 customer categories divided in the following portions, corresponding to the Norwegian energy consumption (1992):

Industry	14.6 %
Trades & Services	29.6 %
Agriculture	1.7 %
Residential	54.1 %.

According to section 8.2 and Table 2.1, this gives a resulting Customer Damage Function (or reference cost) equal to:

CDF(0) = 3.7 NOK/kW
CDF(1) = 20.8 NOK/kWh
CDF(4) = 23.3 NOK/kWh
CDF(8) = 26.0 NOK/kWh.

The relative time variation in failures and repair time is determined using the failure statistics for the southern part of Norway, covering 12.5 years of statistics (105 failures). For the specific cost is used the resulting weighted time variation as given in Fig. 8.2 and Appendix 7. The relative monthly variations in failures and repair time are given in Figs. 8.5 and 8.6 respectively and in Appendix 7.

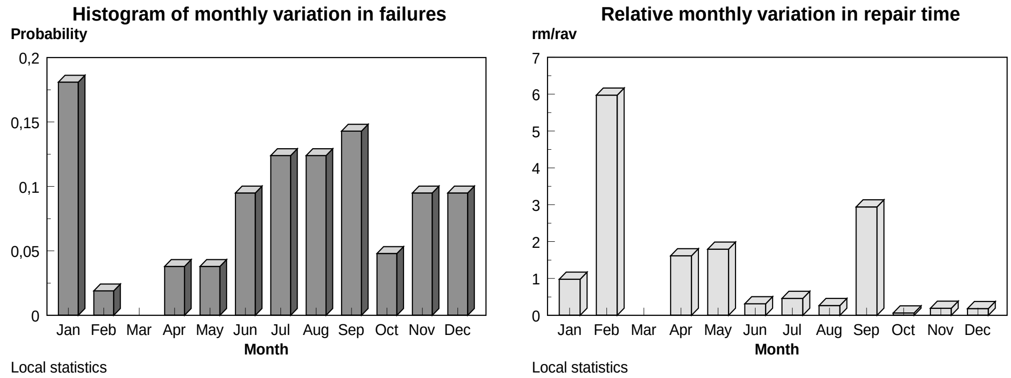


Fig. 8.5 Relative monthly variation in failures and repair time, local statistics.

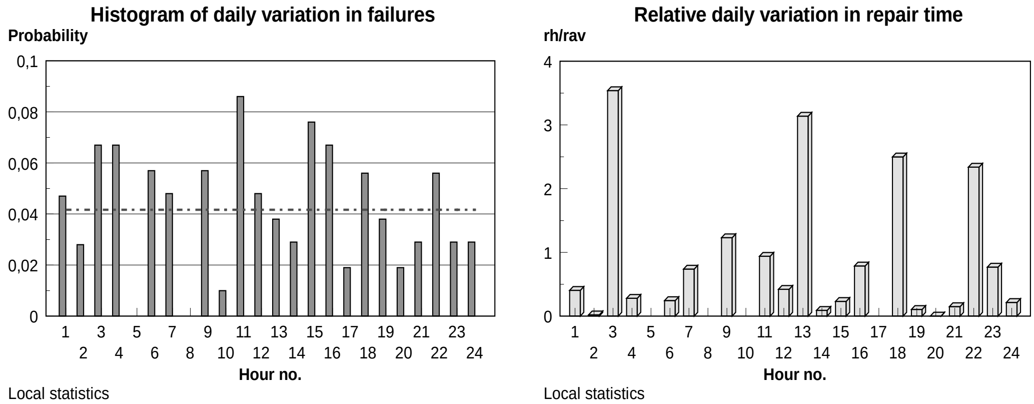


Fig. 8.6 Relative daily variation in failures and repair time, local statistics.

The following cases are included:

- The influence of time variation in failures and other variables on the reliability indices are investigated using the analytical method for meshed systems in Section 6.2.4 and

  - Local statistics for the area, covering 12.5 years and 105 failures
  - Total statistics for lines ≥ 300 kV in Norway, covering 12.5 years and 1770 failures.

- The Monte Carlo simulation method is applied to obtain the probability distributions for the reliability indices, for the case with local statistics.

- A comparison of the developed models with the LARA model for a case based both on the local and the total statistics.

Basic assumptions used in the case studies:

- SAC for the 5 outage events are considered constants
- LG is neglected
- The same time profiles for failures and repair times are used for all outage events
- Maintenance is not included.

8.3.2 Results for the delivery point (Stavanger area)

8.3.2.1 Expectation values and influence of time variation

Local statistics

Expectations are calculated with the analytical method, first considering only the monthly variation in failures and repair time, and next including the daily variation as well. The results are given in Tables 8.2 and 8.3. No time variation in the specific cost is considered in these two cases.

Table 8.2 Expectation values with **monthly** variation in failures and repair time, **local** statistics. No time variation in the specific cost.

Outage event	λ no/year	U hours/year	EPNS MW/year	EENS MWh/year	EIC[2)] kNOK/year
A & B	0.167	0.0262	92	14	587
C1 & C2	0.212	0.0428	28	5.7	207
A + B	0.0025	0.000425	1.4	0.2	9
A + D	0.00019	2.77 E-5	0.1	0.02	0.7
A	0.082	0.014	1.8	0.3	11
Sum	0.46	0.08	124	21	815

EIC[2)] based on reference cost

Table 8.3 Expectation values with **monthly** and **daily** variation in failures and repair time, **local** statistics. No time variation in the specific cost.

Outage event	λ no/year	U hours/year	EPNS MW/year	EENS MWh/year	EIC[2)] kNOK/year
A & B	0.167	0.0261	92	14	596
C1 & C2	0.212	0.041	28	5.6	207
A + B	0.0025	0.000425	1.4	0.2	9
A + D	0.00019	2.76 E-5	0.1	0.02	0.7
A	0.0926	0.016	2.1	0.3	13
Sum	0.47 (+ 2 %)	0.08 (0 %)	124 (0 %)	20 (- 1 %)	825 (+ 1 %)

EIC[2)] based on reference cost

The delivery point will experience an interruption almost every second year. The annual interruption time is about 5 minutes, giving an average interruption time of about 10 minutes per interruption. The annual interruption cost using the reference cost is about kNOK 820.

The two dependent double outages (A&B and C1&C2) contribute about 97 % to EENS and EIC (when maintenance is not considered).

Including the daily variation gives practically no influence on the total results. The deviations compared to Table 8.2 are given in brackets in Table 8.3. The largest differences are observed for the single outage of line A. This outage gives a low reduction in SAC, and from Fig. 8.5, we see that there is a higher probability of having failures in certain hours where the load is high enough to give interruption. In Fig. 8.5 the uniform probability (= 1/24) from hour to hour is marked with a dotted line. This outage however has a very little influence on the total results.

Results for EIC when monthly-, weekly- and daily variation in specific cost is considered are given in Table 8.4.

Table 8.4 EIC with **monthly** and **daily** variation in failures and repair time, **local** statistics. **Monthly**-, **weekly**- and **daily** variation in the specific cost. %-dev. from Table 8.3.

A & B	C1 & C2	A + B	A + D	A	Sum
790	233	12	0.9	13	1049
(+ 32.5 %)	(+ 12.7 %)	(+ 32.5 %)	(+ 32 %)	(+ 6.4 %)	(+ 27 %)

The time variation in the specific cost has a significant influence on the total annual cost which is increased by 27 % compared to using the reference cost.

Total statistics

The daily variation in failures and repair time based on the local statistics is shown to have no practical influence on the expectation values. By a visual inspection of Fig. 8.6 it is difficult to observe any particular pattern in the daily distribution of failures and even less in the repair time. This relative daily distribution is based on 105 failures. If the total number of failures (1771) on lines ≥300 kV in the same period is used instead, we get the monthly-, weekly- and daily variations shown in Figs. 8.7 and 8.8.

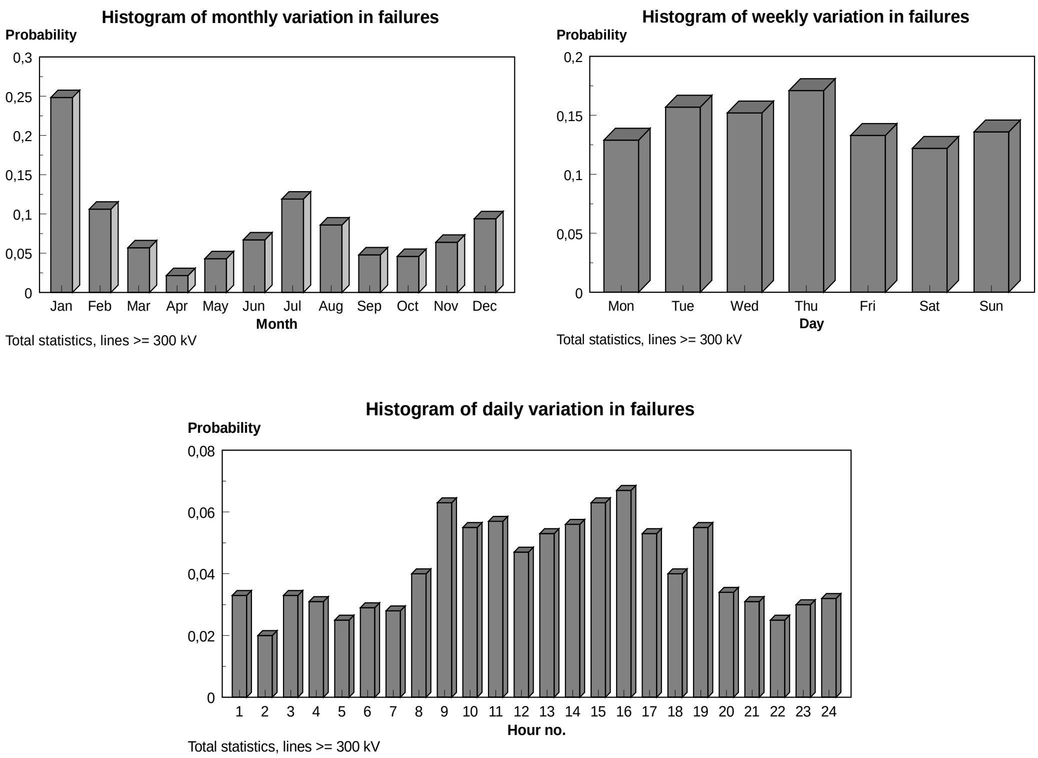


Fig. 8.7 Relative monthly-, weekly- and daily variation in failures, **total** statistics (≥ 300 kV lines).

Expectation values calculated on the basis of failure rates and average repair times from Table 8.1 and the time variations in Figs. 8.7 and 8.8 are given in Tables 8.5, 8.6 and 8.7. First, only monthly variation in failures and repair time is considered (Table 8.5), secondly monthly- and daily- (Table 8.6) and finally the three types of variations are included (Table 8.7). In all three cases, the specific cost is represented by monthly-, weekly- and daily variation.

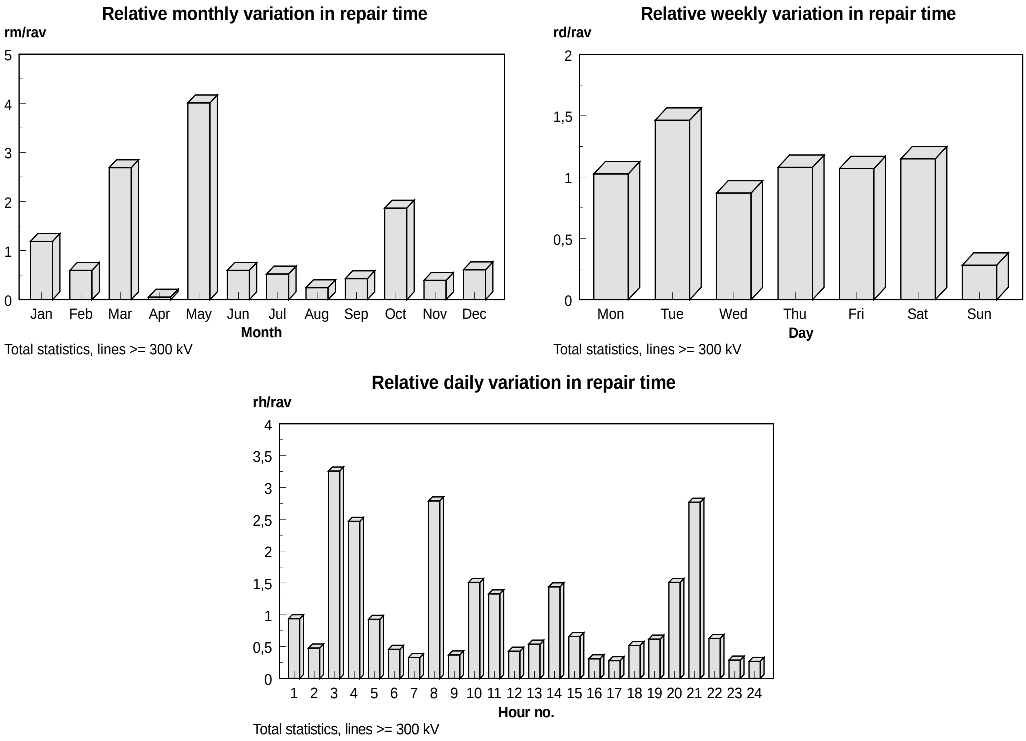


Fig. 8.8 Relative monthly-, weekly- and daily variation in repair time, total statistics (≥ 300 kV lines).

Table 8.5 Expectation values with **monthly** variation in failures and repair time, **total** statistics. **Monthly**-, **weekly**- and **daily** variation in the specific cost.

Outage event	λ no/year	U hours/year	EPNS MW/year	EENS MWh/year	EIC kNOK/year
A & B	0.167	0.0262	100	16	750
C1 & C2	0.297	0.0785	39	10	336
A + B	0.0025	0.000424	1.5	0.3	12
A + D	0.00019	2.77 E-5	0.1	0.02	0.8
A	0.1073	0.0214	2.2	0.4	16
Sum	0.57	0.13	143	27	1114

Table 8.6 Expectation values with **monthly-** and **daily** variation in failures and repair time, **total** statistics. **Monthly**-, **weekly**- and **daily** variation in the specific cost.

Outage event	λ no/year	U hours/year	EPNS MW/year	EENS MWh/year	EIC kNOK/year
A & B	0.167	0.0261	103	16	816
C1 & C2	0.315	0.0793	46	11	405
A + B	0.0025	0.000425	1.6	0.3	13
A + D	0.00019	2.76 E-5	0.1	0.02	0.9
A	0.1428	0.0275	3	0.6	22
Sum	0.63	0.13	154	28	1257

Table 8.7 Expectation values with **monthly-, weekly-** and **daily** variation in failures and repair time, **total** statistics. **Monthly**-, **weekly**- and **daily** variation in the specific cost.

Outage event	λ no/year	U hours/year	EPNS MW/year	EENS MWh/year	EIC kNOK/year
A & B	0.167	0.0261	104	16	828
C1 & C2	0.317	0.0822	47	12	430
A + B	0.0025	0.000424	1.6	0.3	13
A + D	0.00019	2.76 E-5	0.1	0.02	0.9
A	0.150	0.0324	3.1	0.7	25
Sum	0.64	0.14	155	29	1296

These results clearly show the influence of the time variation in failures. There is obviously a positive correlation between the number of failures and the load, leading to more interruptions for the two outage combinations with SAC > 0 MW (C1&C2 and A). *EPNS, EENS and EIC are significantly increased for all outage combinations even though the average failure rate and average repair time are the same as earlier.*

A comparison between the total results in Tables 8.3 (local statistics) and 8.7 shows that the number of interruptions has increased to approximately 1 interruption every 1.5 years with an annual interruption time of 8.5 minutes, giving an average interruption time of about 13.3 minutes. EPNS is increased by approx. 25 %, EENS by approx. 44 % and EIC by approx. 24

% (from Table 8.4).

Fig. 8.9 shows the influence of including the weekly- and daily variation in addition to the monthly (100 %). For instance is EIC increased by 16 % from Table 8.5 to Table 8.7.

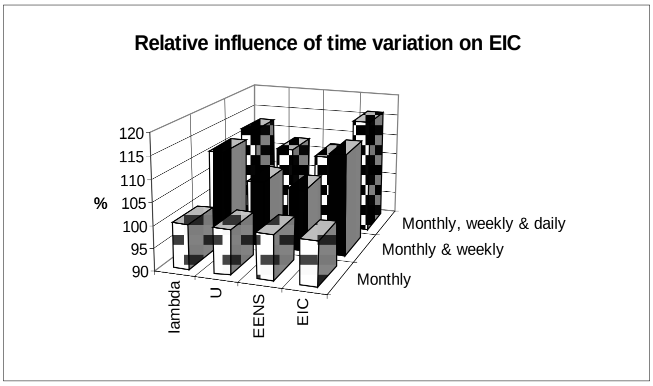


Fig. 8.9 Relative influence of time variation, total statistics for lines ≥ 300 kV.

These results are confirmed by the correlation factors for number of failures (total statistics) versus load, which are calculated to 0.35, 0.54 and 0.75 for monthly-, weekly- and daily variation respectively. The correlation is particularly significant on a weekly- and daily basis. Corresponding correlation factors based on local statistics are -0.15 and 0.0 for monthly- and daily variation respectively.

Influence of time variation

The separate influence on EIC of the time variation in different input variables is illustrated by omitting the variation in both repair time and the specific cost, and by omitting only the time variation in specific cost. The varying failure rate is included to achieve the same interrupted power, such that the results can be compared. Calculations are performed for all 5 outage events, using the reference cost and the annual average cost respectively, for the cases where no time variation is considered in the specific cost.

The *annual average* specific cost is found using the average cost function given below:

$$c_{res,\,av}(0) = 5.2 \text{ NOK/kW}$$
$$c_{res,\,av}(1) = 28.8 \text{ NOK/kWh}$$
$$c_{res,\,av}(4) = 31.3 \text{ NOK/kWh}$$
$$c_{res,\,av}(8) = 35.0 \text{ NOK/kWh.}$$

This average cost function is determined from the relative time variations in the resulting cost (see Fig. 8.2).

It is assumed that the answers are given in Table 8.4 for local statistics and in Table 8.7 for total statistics. The cases with local statistics include only monthly variation in the variables, while the cases with total statistics include monthly-, weekly- and daily variation. The comparison is made in Fig. 8.10, where the results from Tables 8.4 and 8.7 are fixed at 100 %. Only total costs are shown. The analytical method is used in the comparison.

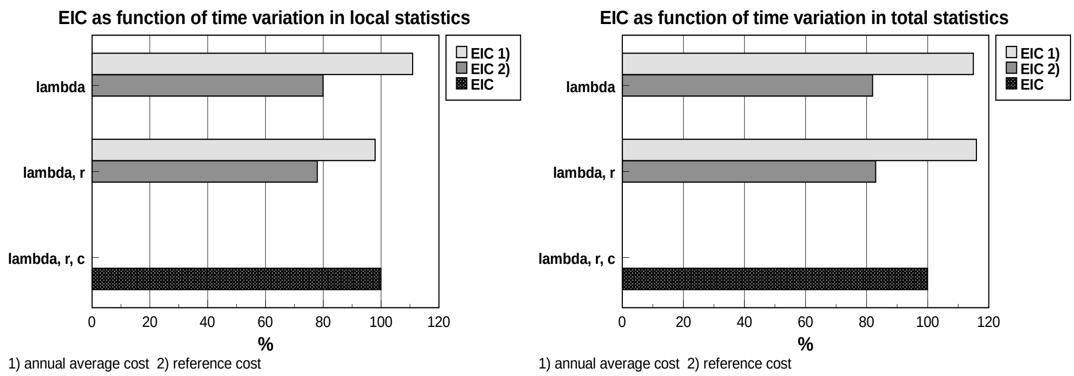


Fig. 8.10 EIC as a function of time variation in input variables compared to results from Tables 8.4 and 8.7.

Fig. 8.10 shows that including the time variation in repair time from the local statistics leads to a reduction in EIC compared to taking only time-varying failure rate into account. This indicates that there is a negative correlation between failures and repair in the local statistics. (The correlation factor on monthly basis is calculated to -0.22). For the case with total statistics there is a neglectable increase in EIC including the time variation in repair time.

Compared to the base cases, the figure shows that EIC will be underestimated by approx. 20 % using the reference cost function without consideration of time variation in specific cost. Using a constant cost function on an annual average leads to an overestimation of EIC by 0-15 % compared to taking time variation in all input variables into account.

As examples of the time variation in reliability indices, the distribution of the annual number of interruptions and the annual interruption cost are shown on a monthly and daily basis in Figs. 8.11 - 8.14. The results are shown only for the two dependent outages A&B and C1&C2, based on the local statistics (to the left in the figures) and the total statistics (to the right).

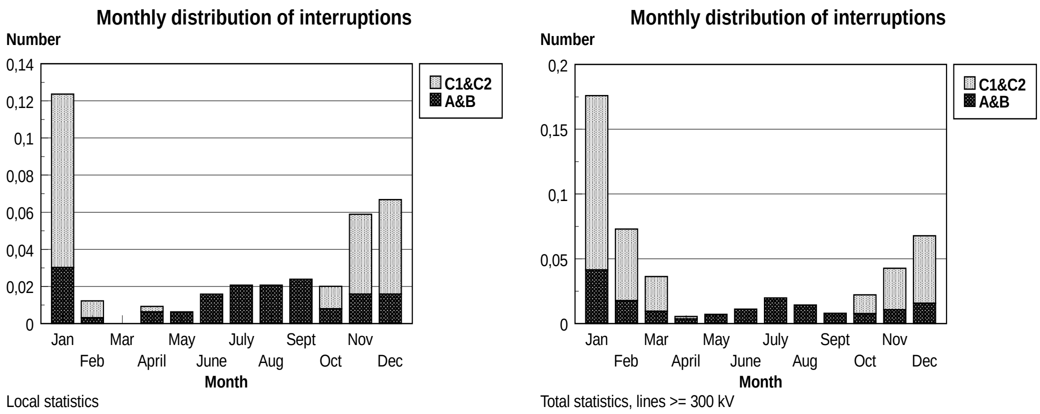


Fig. 8.11 Monthly variation in annual number of interruptions.

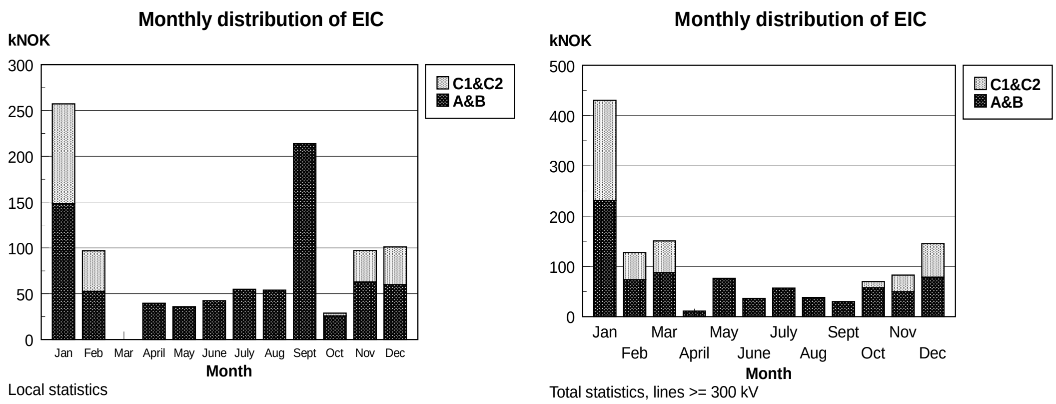


Fig. 8.12 Monthly variation in annual interruption costs.

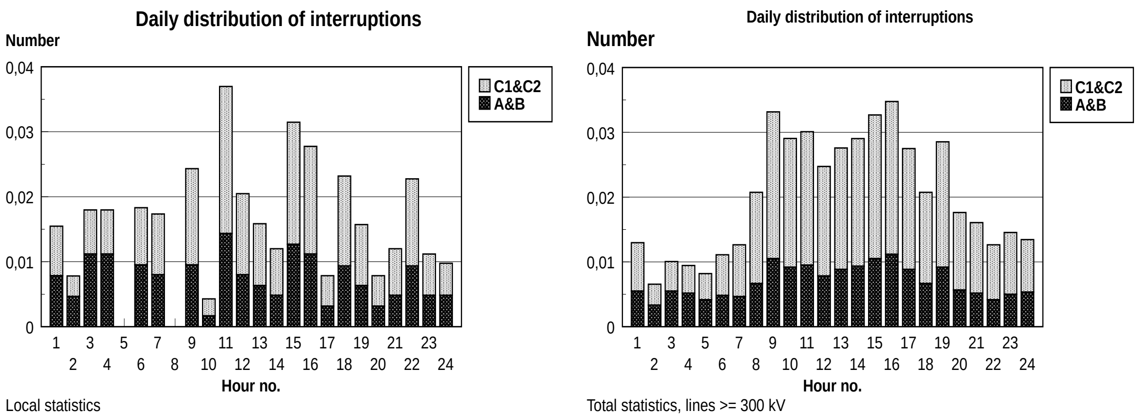


Fig. 8.13 Daily variation in annual number of interruptions.

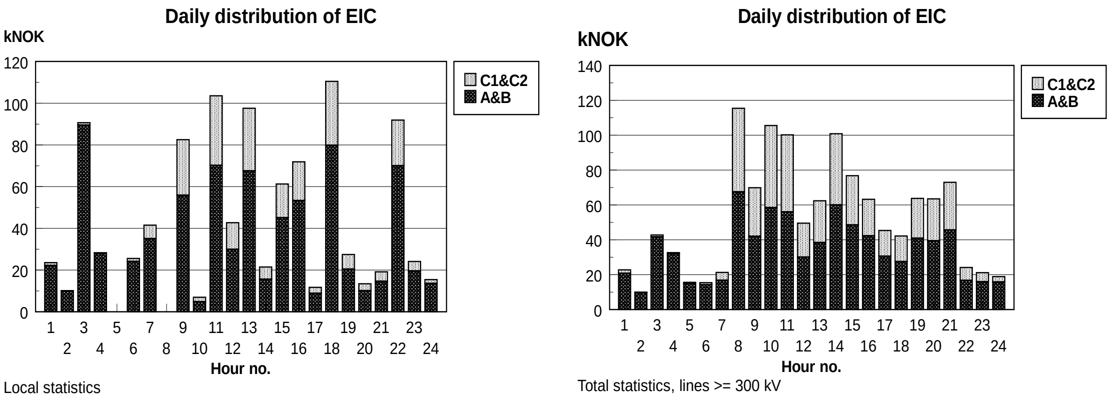


Fig. 8.14 Daily variation in annual interruption cost.

The figures show that the distributions of interruptions for A&B follow the histograms of failures in Figs. 8.5 and 8.6 for the local statistics, and in Fig. 8.7 for the total statistics. This event causes interruption for each failure. For event C1&C2 interruptions occur only in time periods where the load is high. The contribution to interruptions in the different time periods vary according to the histograms of failures. Figs. 8.12 and 8.14 show the combined effect of the time variation in the input variables on the annual costs. The patterns for EIC deviate from the patterns for the annual number of interruptions (λ), especially on a daily basis.

The portion of λ and EIC in different hours of the day (Figs. 8.13 and 8.14) should be interpreted as the amount of the annual indices λ and EIC if the interruption occurs in a particular hour. See also Section 7.3.4.

8.3.2.2 Results of a Monte Carlo simulation

A Monte Carlo simulation is made for the case with local statistics, considering monthly- and daily variation in failures and repair time and time variation in specific cost. 1000 failures are simulated for each outage combination, and the repair time is assumed exponentially distributed. Stochastic variation in load or specific cost is not considered. Since the loading situation is important for the occurrence of interruptions in meshed systems, the load uncertainty might influence the annual reliability indices. However, this aspect is not studied in this case. Without consideration of the load uncertainty the expectation values for the indices will be approximately equal to those obtained by the analytical method.

Expectation values are given in Table 8.8 with the percentage deviations from Tables 8.3-8.4. The results in Table 8.8 are taken from a run giving acceptable deviations from the analytical expectations. With these data the results are quite unstable from run to run when only 1000 failures per combination are simulated. This is mainly due to some very high factors in the monthly- and daily variation in repair time (see Figs. 8.5-8.6).

Table 8.8 Expectations from a Monte Carlo simulation. Percentage dev. from Tables 8.3-8.4.

Outage event	λ no/year	U hours/year	EPNS MW/year	EENS MWh/year	EIC kNOK/year
A & B	0.162	0.024	92	13	777
C1 & C2	0.209	0.038	30	5.8	246
A + B	0.0024	0.00043	1.4	0.2	12
A + D	0.00018	3.0 E-5	0.1	0.02	0.9
A	0.092	0.0173	2.0	0.3	14
Sum	0.47 (- 2%)	0.08 (- 4 %)	125 (+ 1 %)	20 (- 4 %)	1050 (0 %)

The annual expected cost EIC is about NOK 1 million for the local area. A 95 % confidence interval and the 50- and 90 percentiles for EIC are calculated to be:

95 % confidence interval for EIC:	[885, 1214]	kNOK/year
50 percentile for EIC:	717	kNOK/year
90 percentile for EIC:	1629	kNOK/year.

These statistics for the annual cost are calculated approximately, since the year by year calculations are decoupled from the simulations of failures and interruptions in the prototype. The prototype provides results for each interruption. The histogram and cumulative distribution for cost per interruption are given in Fig. 8.15, and the average and percentiles for the cost per interruption are calculated to be:

Average cost per interruption	4332	kNOK per interruption
50 percentile for cost per interruption:	3089	kNOK per interruption
90 percentile for cost per interruption:	6827	kNOK per interruption.

The maximum cost per interruption is NOK 175 million (not shown in the figure). There is a small probability of getting an extremely high cost for a single interruption, but 90 % of the interruptions will have a cost less than NOK 7 million.

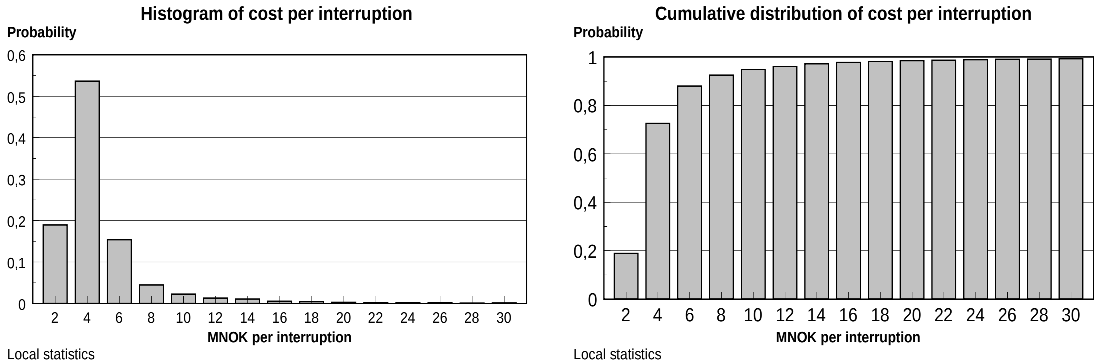


Fig. 8.15 Histogram and cumulative distrib. for cost per interruption for the Stavanger area.

8.3.3 Comparison with the LARA model

This section gives the results from a comparison of the time variation model with the Monte Carlo model LARA. LARA is developed by PTI (Power Technologies Incorporated, USA) and has been tested by The Norwegian Power Grid Company (Statnett) for the Stavanger area in south-western part of Norway. This is reported in [68]. The case is taken from the same area as the one presented in the previous sections, but based on different data.

LARA (Local Area Reliability Assessment) is a time sequential Monte Carlo simulation program which requires a list of possible outage combinations (combinations of outage events) with corresponding import limits (or SAC) as input. The load is represented by a one-year sequential hourly curve (8760 values). It may be classified in three categories: interruptible, firm and critical with separate (increasing) interruption costs. Maintenance periods can be specified.

In LARA the varying failure rates within a year are represented through a weather-based model. For lines the failure rate may be specified as a function of weather conditions. Up to six different weather categories can be defined. Each category is specified with a rate of occurrences (per month) and a duration distribution. Similarly a repair time distribution can be specified for each of the user-defined weather conditions, giving a relative variation in repair time over the year.

LARA is applied to the case presented in Table 8.2, considering monthly variation in failures and repair time based on local statistics. In LARA, lightning is modelled (in addition to normal weather), and exponential distribution is assumed for the repair time.

The analytical method is applied in this comparison. It is assumed that this method and the developed Monte Carlo method will provide the same results since the cost function is practically linear. The same basic assumptions as in Section 8.3.1 are used in these calculations.

The results for LARA and the analytical method are given in Table 8.9 for the two dependent double outages (A&B and C1&C2), with failure rates and average repair times from Table 8.1 and using the reference cost. The repair time is rounded off to 0.2 and 0.3 hours respectively. The reference cost is also rounded off. The same time variation is assumed in failures and repair time for all outage combinations. LARA results are provided by Statnett.

Table 8.9 Comparison of LARA and the time variation method. **Monthly** variation in failures and repair time, **local** statistics for the area. No time variation in specific cost. Repair time exponentially distributed.

Outage event	λ, no. per year		EENS, MWh/year		EIC kNOK/year	
	Time var. model	LARA	Time var. model	LARA	Time var. model	LARA
A & B	0.17	0.17	18.3	18.1	685	702
C1 & C2	0.21	0.21	6.8	7.6	236	252
Sum	0.38	0.38	25.1	25.7	921	954

The two models give the same number of interruptions for the delivery point. LARA gives 2.4 % higher EENS and 3.6 % higher EIC than the time variation method. These differences are small and are partly attributed to numerical differences and partly to the different modelling of the variables.

Results from a case based on the total statistics for lines ≥ 300 kV are given in Table 8.10. Only monthly variation in failures and repair time is considered.

Table 8.10 Comparison of LARA and the time variation method. **Monthly** variation in failures and repair time, **total** statistics for lines ≥ 300 kV. No time variation in specific cost. Repair time exponentially distributed.

Outage event	λ, no. per year		EENS, MWh/year		EIC kNOK/year	
	Time var. model	LARA	Time var. model	LARA	Time var. model	LARA
A & B	0.17	0.17	20.4	22.6	719	804
C1 & C2	0.30	0.28	11.9	13.0	350	394
Sum	0.47	0.45	32.3	35.6	1069	1198

The differences between LARA results and results from the time variation model are somewhat larger in this case. For A&B the deviation in EENS is about 10 % and EIC about 12 %. For C1&C2 there is a difference of 7 % in the number of interruptions, 9 % in EENS and 13 % in EIC.

The influence of the time variation based on total statistics is particularly significant for the outage event C1&C2. A comparison with Table 8.9 shows an increase of 75 % for EENS and 48 % for EIC (for the time variation model).

The main purpose of the comparison with LARA is to evaluate the two different models for representing time variation in input variables. It is necessary to adjust the data due to numerical differences and the different modelling of the variables in the method to achieve comparable results. Only monthly variation in failures and repair time and no time variation in specific cost is considered.

The comparison in Tables 8.9 and 8.10 shows that the model developed in this work gives practically the same results (within ± 10 %) as obtained with LARA, even though the representation of the varying failure rate is quite different. The analysis is however limited since the same time variation in failures and repair time for all outage combinations is assumed. It is possible to include this aspect by allocating different time profiles for the different events in the developed model and by modelling different weather dependency in LARA. Such studies are not carried through in this work.

Summary of results:

Throughout this section the same basic assumptions are used. Neglecting local generation within the local area result in pessimistic estimates of EPNS, EENS and EIC, while neglecting the maintenance have probably yielded too optimistic results. The principles are retained, since the overlap between maintenance and failures can be represented by additional outage events. However, to obtain realistic estimates these two aspects should be included.

To illustrate the main principles of the methods developed, the case is further simplified by assuming the same time variation in failures and repair for all outage combinations. The examples have shown that the pattern of the time profiles for failures and repair time may be of significant importance. If there is no characteristic pattern, i.e., a random time variation in failures (like in the local statistics), the annual interruption costs are scarcely influenced by the time variation on a weekly and daily basis. However, a characteristic cyclic pattern on a weekly and daily basis using the total statistics for lines ≥ 300 kV, has a significant influence on the reliability indices: EPNS, EENS and EIC are increased by 25 %, 44 % and 24 % respectively, even though the average failure rate and average repair time are the same as earlier. This is mainly due to an increased probability of failures in time periods where the load is high, leading to more interruptions.

The examples in this section have also shown that using the reference cost function without consideration of time variation in specific cost, leads to an underestimation of EIC of about 20 %.

The ability of the cyclic time variation model to represent the time-varying failure rate and repair time is confirmed by a comparison with the LARA model, which is a weather-based model for representation of the time-varying failure rate. The results from the two methods are within ± 10 % from each other.

8.4 Distribution system - case

In this section the methods are being applied to a distribution system supplying several delivery points. This problem is quite different from the earlier examples, where a single delivery point has been considered, although with different customer categories connected. Reliability indices are found using the method for radial systems in Section 6.2, and which is demonstrated for a simple radial system in Section 7.6.

The case is from Trondheim Energy Board (TEV), the electric utility serving the city of Trondheim, see the map in Fig. 8.16. TEV covers an area of 530 km^2 and delivers about 2600 GWh per year to about 80000 customers. The case is described in next section.

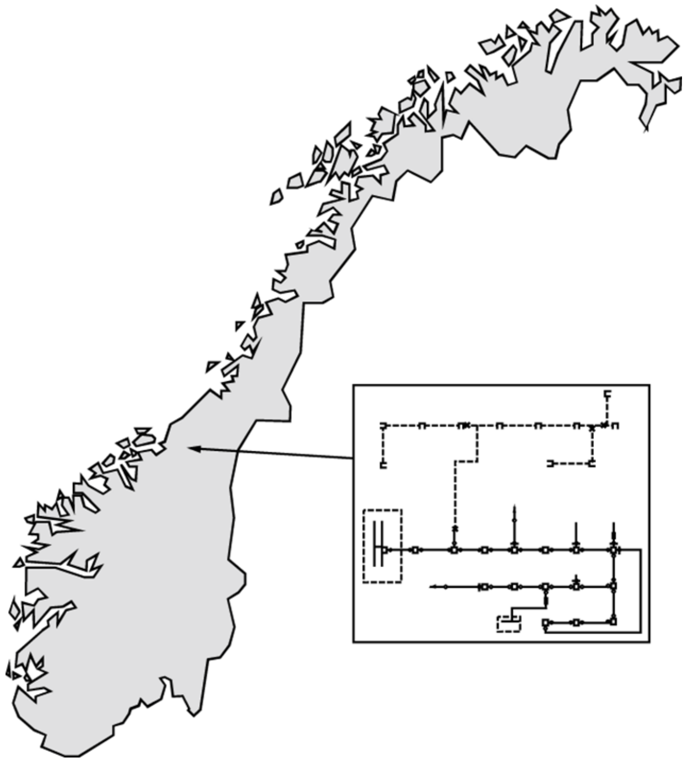


Fig. 8.16 Distribution system case, Trondheim.

8.4.1 Description of case and data

The distribution system under study consists of an underground cable network (12 kV) supplying a densely built-up area with numerous residential customers, some large commercial customers and a few industrial customers. A lateral overhead line (12 kV) serves some scattered residences. The maximum load in the area is P_{max}= 4158 kW (1995), where 89 % is supplied by the cable network. Total cable length is 7.8 km and length of overhead lines is 5.4 km. A single line diagram of the distribution system is given in Fig. 8.17.

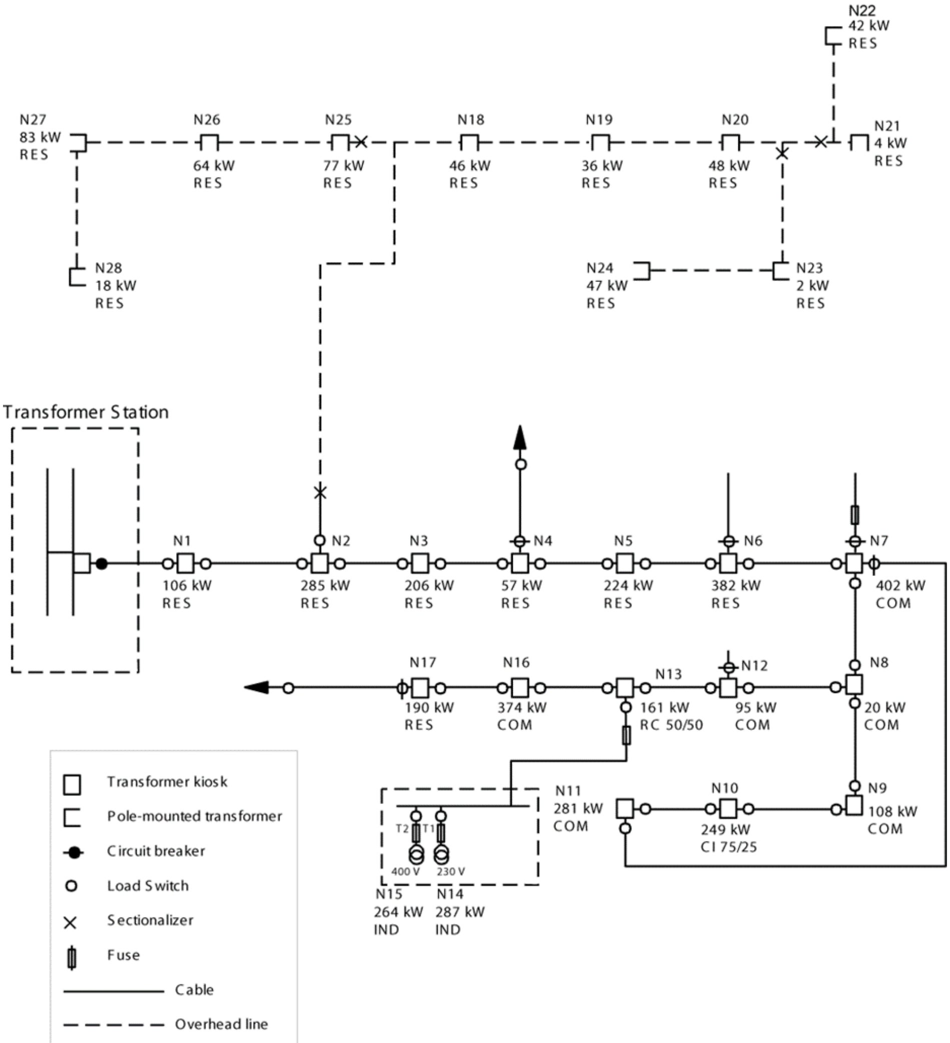


Fig. 8.17 Single line diagram of the distribution system.

Most of the failures occur in the overhead part of the network, each time causing interruptions to the commercial area. TEV has therefore proposed two different alternatives to improve the reliability to this area:

- Install a circuit breaker with remote control at the starting point of the lateral, i.e. at delivery point N2
- Build a new cable from the transformer station to the overhead network, splitting the network in two radials.

8.4.1.1 Delivery points: **Loads and specific costs**

The maximum load per delivery point and the types of customers are shown in Fig. 8.17.

The variations in the commercial and industrial loads are assumed equal to the typical load curves given in Chapter 4, Figs. 4.9 and 4.10, and equal utilization times are assumed as those inherent in the general profiles. Variation in residential load is summarized in some correction factors taken from [76] (see Section 8.4.2.1).

There are 5 customer categories (marked in Fig. 8.17) with different cost functions. The cost functions at reference time are given in Table 8.11:

Table 8.11 Cost functions (CDF's) at reference time. 1995 cost level.

Customer category	CDF(0) NOK/kW	CDF(1) NOK/kWh	CDF(4) NOK/kWh	CDF(8) NOK/kWh
Residential (RES)	0.0	2.4	9.1	10.8
Commercial (COM)	7.4	38.7	40.4	46.4
Industrial (IND)	10.8	55.3	43.7	43.3
Res./comm. 50/50 (RC 50/50)	3.7	20.6	24.8	28.6
Comm./ind. 75/25 (CI 75/25)	8.3	42.9	41.2	45.6

The relative time variations in specific interruption costs for commercial and industrial loads from Ch. 4 (Figs. 4.13 and 4.14) are used in this case.

8.4.1.2 Failures and interruptions

Failure rate and repair time for 12 kV overhead lines and cables at TEV are given in Table 8.12. Failures on other components such as distribution transformers and sectionalizers are not considered in this case.

Table 8.12 Failure statistics, 12 kV, TEV.

Component	Failure rate (no. per km, per year)	Repair time (hours per failure)
Overhead line	0.3229	1.14
Cable	0.0566	6.73

The average sectioning (restoration) time is 53 minutes, while the sectioning time at point N2 is 30 minutes.

For any failure in the system, delivery points in the cable network are provided alternative supply from the different reserve (open) connections to other radials within the distribution system at TEV. The open connections are marked in the figure. Failures in the overhead part will give 30 minutes restoration time to the cable delivery points, while failures within the cable network will give 53 minutes except for N1 and N2.

In the overhead part of the network there is no reserve. Failures in cables 1 and 2 will lead to repair time for all the delivery points in the overhead network, while failures in the other cables result in 30 minutes interruption time to these delivery points.

The relative time variation in failures and repair- or sectioning time used in this case are the general variations from the failure- and interruption statistics for distribution systems given in Chapter 4, Figs. 4.3, 4.4 and 4.6 and Appendix 6. The relative time variation for the sectioning (or restoration) time is assumed equal to the relative time variation for repair time.

8.4.2 Reliability indices for the distribution system

Reliability indices are calculated according to the procedure described in Section 6.2.3, for each delivery point and for the system as a whole. For this radial system, the expectations are found using P_{max} and correction factors including the time dependent correlation.

8.4.2.1 Correction factors

General correction factors are applied in this case, although we might have used separate correction factors for lines and cables, as is shown in Section 6.2.3. The factors are calculated for each customer type, except for residential load, where the correction factors are taken from [76]. The residential factors are based on limited data. The correction factors for the three types of load are given in Table 8.13.

Table 8.13 Correction factors for commercial, industrial and residential loads.

Customer type	$k_{\lambda P}$	$k_{\lambda Pr}$	$k_{\lambda Prc}$
Commercial	0.480	0.485	0.668
Industrial	0.468	0.432	0.493
Residential	0.680	0.760	0.670

8.4.2.2 Expectation values

Average and sum results for the delivery points are given in Table 8.14. The detailed results per delivery point are given in Appendix 7.

Table 8.14 Reliability indices for the delivery points.

Delivery points	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
Cable network, N1- N17	2.19	1.25	0.57	4553	2718	85959
Overhead network, N18 - N28	2.19	2.23	1.02	698	795	2033
Average/ SUM	2.19	1.64	0.75	5252	3513	87992

All delivery points experience more than 2 interruptions a year. The annual interruption time in the overhead part of the system is almost twice the annual interruption time in the cable network. This is due to the lack of reserve supply in the overhead network. The delivery points supplied by the cable network account for 77 % of EENS and 98 % of EIC.

The Interrupted Energy Assessment Rate IEAR is found by Eq. (2.2):

$$IEAR = \frac{EIC}{EENS}$$

for the system as a whole. This definition differs from the one used in [43, 46], where IEAR is calculated for each delivery point, and the system IEAR is found by weighting the individual

IEARs with the portion of the total load at the delivery points.

IEAR represents the average specific interruption cost for a given supply situation and a given reliability level. This index is calculated to 31.6 NOK/kWh for the cable network, 2.6 NOK/kWh for the overhead network and *25.1 NOK/kWh for the system as a whole*.

The delivery points N25-N28 have the worst interruption conditions according to the number and duration of interruptions, while N7 has the largest annual interruption cost. This is a commercial customer. EIC for N7 is NOK 15021, corresponding to 17 % of the total EIC (see Table A7.1).

To compare the expectation values given in this section with indices obtained using the traditional method, EPNS, EENS and EIC are calculated on the basis of the average load. The traditional method[1)] gives the following expectations. Deviations from Table 8.14 are given in brackets:

EPNS[1)] = 4242 kW/year (- 19 %)
EENS[1)] = 2660 kWh/year (- 24 %)
EIC[1)] = 86970 NOK/year (- 1 %)
EIC[2)] = 62234 NOK/year (- 29 %).

These results are in accordance with the small example in Section 7.2. The traditional method gives practically the same annual costs when the average[1)] specific cost is used, while using the reference[2)] cost underestimates EIC. In this case the traditional method also significantly underestimates EPNS and EENS. This is partly due to the relatively high correction factors for the residential loads (Table 8.13). These factors are based on limited data.

8.4.2.3 Results after improvements

Reliability calculations are made for the two alternative ways of improving the reliability level:

- Circuit breaker in the lateral, at point N2 (Alt.2)
- New cable with circuit breaker from the transformer station to point N2 (Alt.3).

The two alternatives are shown in Fig. 8.18, the existing system being alternative 1.

The circuit breaker at point N2 (alt. 2) is assumed to isolate all failures within the overhead network, thus improving the reliability to the delivery points in the cable network, while the reliability to the delivery points in the overhead part is unchanged.

Alt. 3 splits the distribution system in two separate parts, or two different radials, thus improving the reliability to all delivery points in the area.

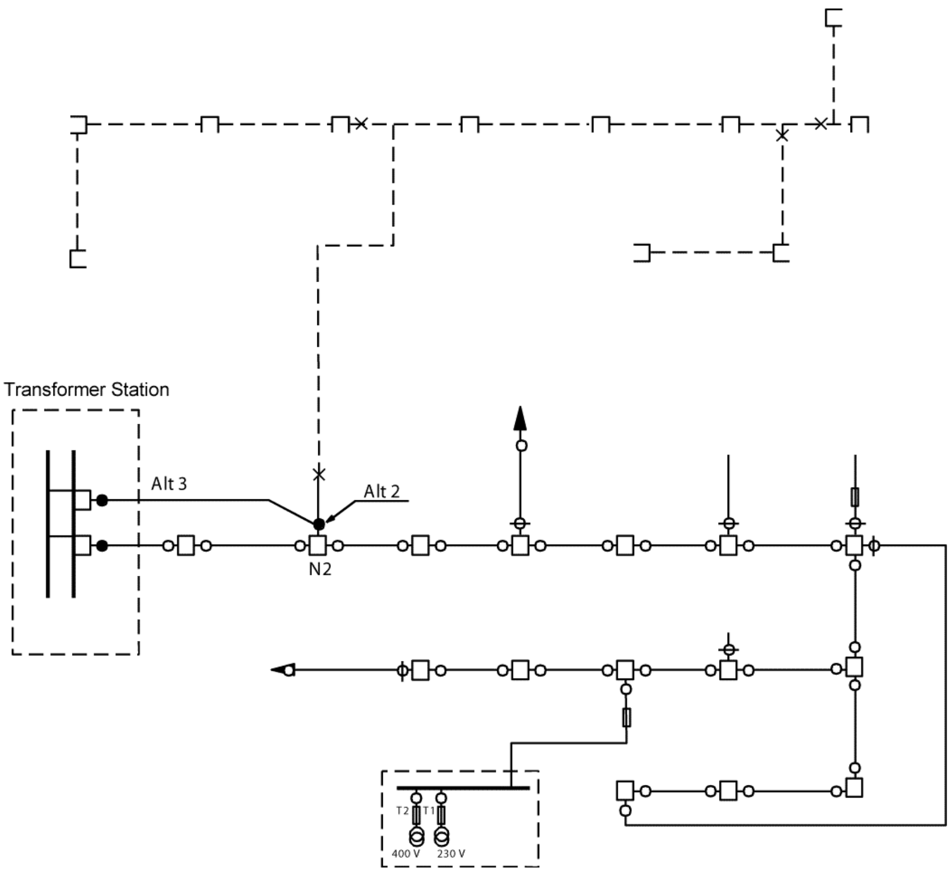


Fig. 8.18 Single line diagram of existing system and with the two alternative investments.

Reliability indices for the two alternatives are given in Tables 8.15 and 8.16 respectively, with details per delivery point in Appendix 7.

Table 8.15 Average reliability indices for the delivery points. **Circuit breaker** at N2.

Delivery points	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
Cable network	0.44	0.37	0.83	909	798	23629
Overhead network	2.19	2.23	1.02	698	795	2033
Average/ SUM	1.13	1.10	0.98	1607	1593	25668

Table 8.16 Average reliability indices for the delivery points. **New cable** - two radials.

Delivery points	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
Cable network	0.44	0.37	0.83	909	798	23629
Overhead network	1.77	2.04	1.15	568	727	1901
Average/ SUM	0.96	1.02	1.06	1477	1524	25530

By installing a circuit breaker at point N2 (alt. 2), significant improvements are achieved in the cable network. The number of interruptions and EPNS are both *reduced to* 20 % of the original, while the annual interruption time and EENS are both reduced to 30 %. EIC is reduced to 27 % compared to the original. *IEAR for this alternative is 16.1 NOK/kWh* for the system as a whole.

Splitting the network in two radials leads to a further reduction in the total indices. The reliability level is unchanged for the delivery points in the cable network (compared to alt. 2), but improvements are made for the overhead part. Here the number of interruptions and EPNS are *reduced by* 20 %, annual interruption time and EENS by about 10 % and EIC by 7 % compared to the original. *IEAR for this alternative is 16.8 NOK/kWh*.

The total EENS and EIC are practically equal for the two alternatives, since the delivery points in the overhead network contribute little to the total indices.

8.4.2.4 Uncertainties

Dispersions in the annual reliability indices can be found applying the Monte Carlo simulation method for the different delivery points and for the system as a whole. Performing Monte Carlo simulations for all line and cable sections and registering consequences to the 28 delivery points will become a comprehensive task, requiring large computation time. However if it is assumed that the different variables has the same probability distribution, e.g. that all the loads are Normally distributed, that the specific cost for each delivery point follows the same distribution etc., the dispersions in the total ENS and IC can be found approximately by running Monte Carlo simulations based on the total indices λ and r.

Uncertainty in annual interruption costs for a particular delivery point

As an example a Monte Carlo simulation is made for delivery point N7 which has the highest interruption costs. The annual number of interruptions λ = 2.19 and the average interruption time r = 0.58 hours per interruption are taken from Table A7.1 in Appendix 7, for the existing system solution. The interruption time is assumed exponentially distributed. Both the load and the specific costs are assumed Normally distributed. P_{max} for N7 is 402 kW, and the commercial cost function from Table 8.11 is used. The general time variations from Chapter 4 are applied for the different variables.

Fig. 8.19 presents the histograms for the interruption time and the cost *per interruption* for N7. The histogram for the interruption time r follows the characteristic form of the exponential distribution, in accordance with the assumption in this example. As expected the tail of the histogram for the cost per interruption follows the histogram for r. The expected cost per interruption and the 50- and 90 percentiles are as follows:

Cost per interruption:	NOK 6872 per interruption
50 percentile:	NOK 4941
90 percentile:	NOK 14034.

50 % of the interruptions will give a cost less than NOK 5000, while there is 10 % probability that the cost will exceed NOK 14000, under these assumptions.

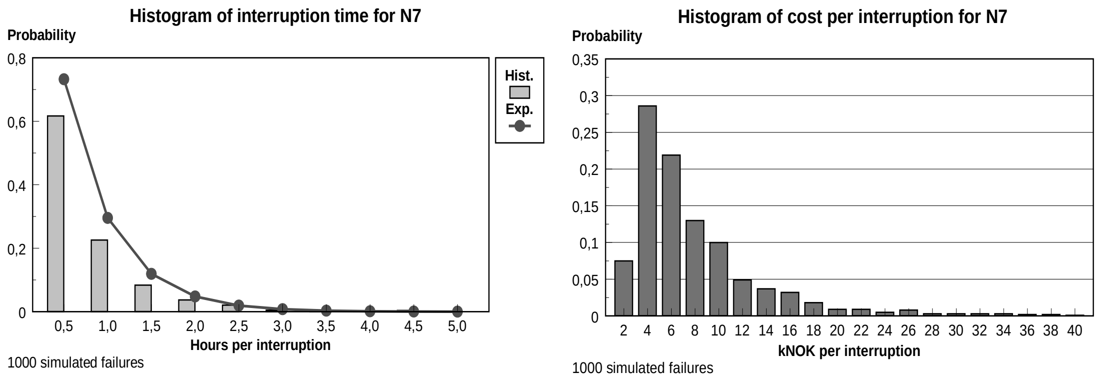


Fig. 8.19 Histograms of interruption time and cost per interruption for delivery point N7.

The *annual* expected interruption costs with a 95 % confidence interval are calculated to be:

EIC =	NOK 15049
95 % confidence interval:	NOK [14478, 15620] ± 4 %.

EIC is in accordance with the result of NOK 15021 from the analytical method.

The Monte Carlo simulation gives the dispersions from year to year (or from interruption to interruption) in different reliability indices due to the stochastic variations in different variables. The uncertainty in EIC resulting from the statistical variation is about 4 %, described by the confidence interval.

A fuzzy description of uncertainty in IC for the delivery point is given by fuzzifying the *average interruption time* and the *specific interruption cost* (see Ch. 6). No uncertainty is considered in λ, P_{max} or the correction factors.

Both variables are represented by trapezoidal membership functions. The corners for r are given by ± 10 % and ± 40 % of the expectation (0.58 hours) respectively, while the corners of c is found by ± 25 % (of the expectation) and ± 50 % respectively. This gives the following corners of the membership function for IC, shown in Fig. 8.20:

IC = NOK [7516, 11274, 18790, 22548].

This means that there is equal possibility of having an annual cost between 11274 and 18790 for this delivery point, i.e. ± 25 % of the expectation.

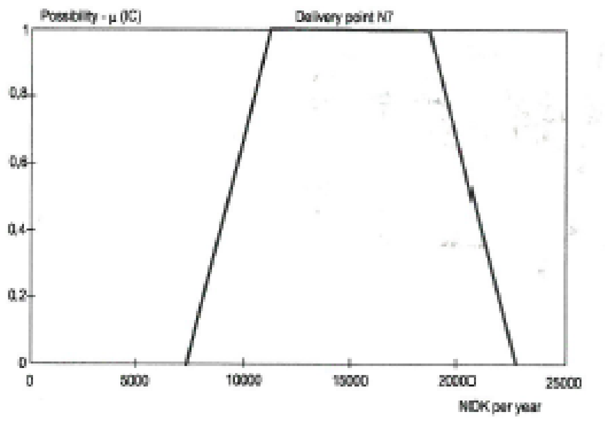


Fig. 8.20 Membership function for IC for delivery point N7.

IC is calculated according to Eq. (6.27) and the procedure described in Section 6.4. The specific cost is referred to the interrupted load (in NOK/kW). Therefore the uncertainty in interruption time is not included in the fuzzy description of IC. Thus, the corners of IC are given by the same relative figures as the corners of the specific cost. If IC is calculated as the product of ENS and the specific cost in NOK/kWh, including the uncertainty in r, we get the following corners:

IC = NOK [4510, 10147, 20669, 31568].

Including the uncertainty in r gives a wider membership function, and the two corners in the middle are now about 35 % away from the expectation.

Uncertainty in interruption costs for the total system

The uncertainty in IC for the whole system can be approximately determined in the same way, by fuzzifying the *total indices*, assuming the same relative uncertainty in each individual variable composing each index.

The average interruption time for the system and the average specific cost is fuzzified by the same relative deviations from the expectations as in the previous section for delivery point N7. The expectations are taken from Tables 8.14 - 8.16 for the three alternatives. Since there are 28 different delivery points experiencing varying interruption times, it is not possible to determine a composite Customer Damage Function for the specific interruption cost. Instead IEAR is used. This index expresses the average specific cost in NOK/kWh for the system (including time dependent correlation). It is transformed to a specific cost in NOK/kW in accordance with Eq. (6.27).

Since the starting point for description of the uncertainty in IC is the *final result,* the calculation is performed “backwards” using resulting correction factors. An example is shown in the following for alternative 1 (existing system solution, Table 8.14):

$$EENS_{\max} = P_{\max} U = 4158 \bullet 1{,}64$$
$$k_{\lambda Pr,res} = \frac{EENS}{EENS_{\max}} = 0.517$$

The expected specific cost is c(r) = IEAR · r = 18.7 NOK/kW. IEAR contains the correlation between the specific cost and the other variables (cfr. Section 7.2). EIC can now be expressed as

$$IC = ENS \bullet IEAR = \lambda\, P_{\max}\, r\, k_{\lambda Pr,res}\, IEAR$$
$$= \lambda\, P_{\max}\, k_{\lambda Pr,res}\, c(r)$$

In this expression for IC, c(r) is a fuzzy variable, giving a fuzzy IC with corners as given in Table 8.17 for the three alternative system solutions. Since IC is calculated on the basis of the specific cost referred to the interrupted load (in NOK/kW) instead of the energy not supplied (in NOK/kWh), the uncertainty in interruption time is not included in the fuzzy description of IC. As for the fuzzy IC for delivery point N7 in the previous section, the fuzzy IC for the whole system is given by the same relative figures as the fuzzy specific cost (i.e., corners given by ± 25 % and ± 50 %).

Table 8.17 Corners of membership functions for EIC for the whole distribution system.

System solution	a_1	a_2	a_3	a_4
Alt. 1	43996	65994	109990	131998
Alt. 2	12834	19251	32085	38502
Alt. 3	12765	19147	31912	38295

The membership functions for the three alternatives are given in Fig. 8.21.

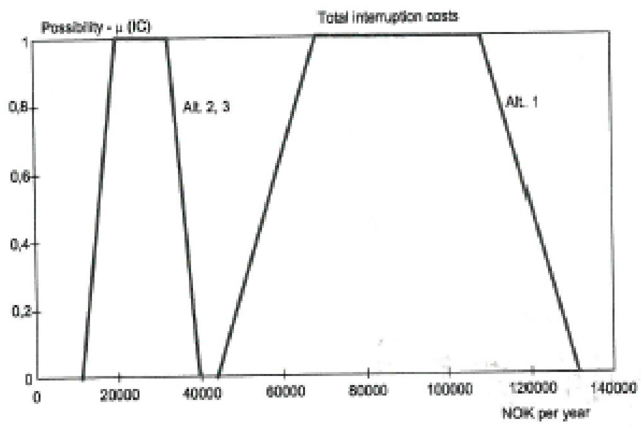


Fig. 8.21 Membership functions for the total IC for the distribution system.

As an example of inclusion of the uncertainty in interruption time, IC for the existing system is calculated as the product of ENS and IEAR, where both are fuzzy variables. This gives the following IC:

IC = NOK [26398, 59395, 120989, 184784]

As for delivery point N7, the membership function for IC is widened, and the middle corners now deviate about 35 % from the expectation.

8.4.3 Cost-benefit analysis

The two alternative system solutions from the previous sections are analysed on a technical and economic basis, to determine if it is justifiable to make the improvements and find the optimal solution. The two alternatives will not make any noticeable changes in electrical losses. The annual interruption costs will therefore be the only variable cost (maintenance cost is neglected). The annual interruption cost will increase according to the load increase (it is assumed that there is no change in interruption cost in the near future except for inflation). Thus the relative difference between the two alternatives will be the same from year to year, and the cost-benefit analysis is performed on a one-year basis. The investment costs are as follows (1995):

Alt. 2 Circuit breaker at N2 including remote control. NOK 171000,-.
Annuity ΔI_2: NOK 18810,-

Alt. 3 New cable with circuit breaker from the transformer station. NOK 454000,-
. Annuity ΔI_3: NOK 34050,-.

For alternative 2, an economic life time of 15 years is assumed and 40 years for alternative 3. The rate of interest is 7 %, yielding annuity factors ε = 0.110 and ε = 0.075 respectively.

The benefit for each alternative represents the reduction in annual interruption costs (ΔEIC) compared to the existing system solution (alt. 1). This is taken as a positive value. The difference between the benefit (ΔEIC) and the cost (ΔI) gives the net revenue (ΔNR), which should be greater than zero if the alternative is economically justifiable:

$$\Delta NR = \Delta EIC - \Delta I > 0$$

The benefits expressed by both ΔEIC and ΔEENS, the net revenue and the break-even cost are given in Table 8.18.

Table 8.18 Cost-benefit analysis for the two alternatives.

Alternative	ΔEENS (kWh/year)	ΔEIC (NOK/year)	ΔI (NOK/year)	ΔNR (NOK/year)	$IEAR_e$ (NOK/kWh)
Circuit breaker	1920	62324	18810	43514	9.8
New cable - two radials	1989	62463	34050	28413	17.1

The two alternatives are quite equal with respect to the total EENS and EIC for the system. Both have a positive net revenue, which means that both are justifiable from a technical and economic point of view.

Alt. 2 has the lowest investment cost, giving the highest net revenue and is obviously the most cost-effective of the two. This is also illustrated by the break-even cost $IEAR_e = \Delta I/\Delta EENS$ which represents the specific interruption cost that makes the investment cost-effective. Alt. 2 is cost-effective for any IEAR higher than 9.8 NOK/kWh. Both alternatives have a break-even cost lower than IEAR for the existing system which was found to be 25.1 NOK/kWh. IEAR will be reduced to about 16 NOK/kWh after the improvements are made by either of the two alternatives.

Alt. 2 improves the reliability to the delivery points served by the cable network, while alt. 3 improves the reliability to the delivery points in the overhead part as well. Alt. 3 is probably a better alternative than alt. 2 from a technical and operational point of view, and since both alternatives are cost-effective, alt. 3 should be chosen (if it is economically justifiable for the utility management). Theoretically however, alt. 2 is the optimal solution. This is illustrated in Fig. 8.22 where the specific and annual costs are shown as a function of the reliability level, alt. 1 with the poorest reliability and alt. 3 with the highest reliability level of the three. The figure gives a qualitative expression of the reliability level.

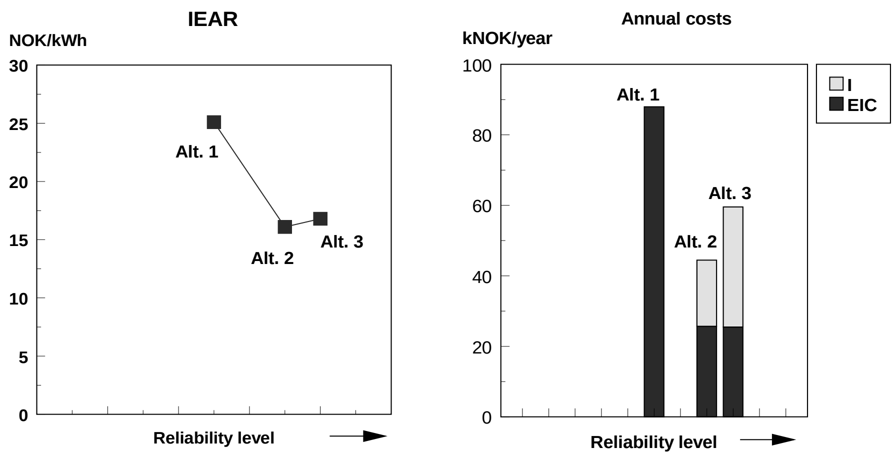


Fig. 8.22 Specific and annual costs as a function of the reliability level.

IEAR in Fig. 8.22 represents the average specific cost for a given reliability level. The figure shows that alternative 2 has the lowest total annual socio-economic cost. The annual cost of the historical investments for the existing network is not included. These costs represent an annuity which is equal for the three alternatives.

The cost-effectiveness of the two alternatives including uncertainties in IC is illustrated in Fig. 8.23. The figure shows the membership function for the reduction in annual interruption costs for alt. 2, found by the subtraction of two fuzzy numbers. The difference between alt. 1 and alt. 3 is practically equal to the difference between alt. 1 and 2. The two crisp annuities ΔI_2 and ΔI_3 (alt. 3) are marked with vertical lines in the figure.

Any of the two alternatives are cost-effective as long as the benefit (ΔIC) is larger than the annual cost of the investment. The cost-effectiveness is represented by the area under the membership function to the right of the vertical lines (the annuities), i.e. by the space of possible outcomes to the right of ΔI. There is a small area for both of the alternatives where the alternative is not cost-effective (to the left of the annuity). These areas are marked (shaded) in the figure. For both alternatives, the whole part of ΔIC with membership equal to 1 lies to the right of the investment cost, giving a high degree of certainty that both investments are cost-effective.

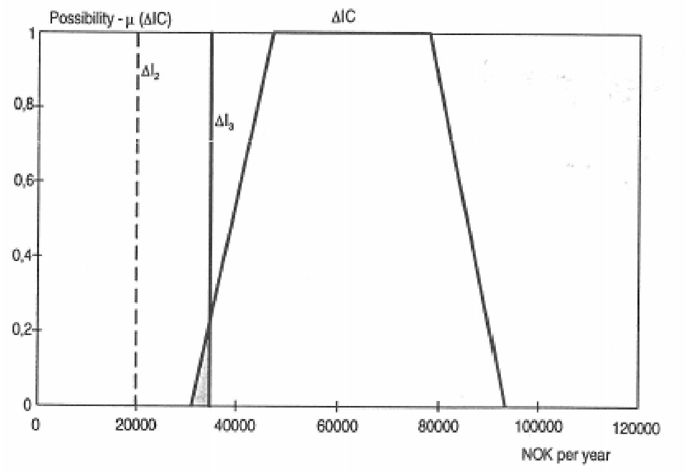


Fig. 8.23 Cost-effectiveness with fuzzy ICs (*corrected*).

There might be uncertainties associated with the investment costs. Let us assume 10 % uncertainty described by a fuzzy interval with corners ± 10 % and ± 20 %. This gives the following corners of the membership functions for the two annuities:

ΔI_2 = NOK [15048, 16929, 20691, 22572]
ΔI_3 = NOK [27240, 30645, 37455, 40860].

The total annual socio-economic costs for the three alternatives are now found by a summation of two fuzzy variables. The total fuzzy costs are given in Fig. 8.24 as a function of the fuzzy annual interruption time. The figure shows the values for a confidence level of α = 0.5 and α = 1 (full membership).

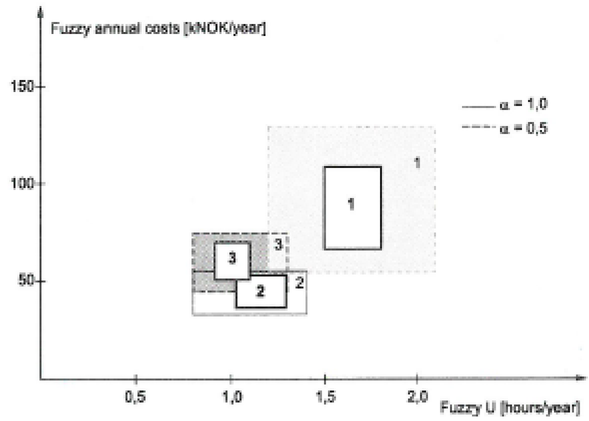


Fig. 8.24 Total fuzzy annual costs as a function of fuzzy annual interruption time.

Fig. 8.24 can be compared to Fig. 8.22 (seen in reverse). Alt 2 is still the theoretically optimal solution, having the lowest annual costs, at least for α = 1. Alt. 3 is however quite close to alt. 2 with some overlapping parts of the membership functions for α = 0.5.

Whether the alternatives are economically justifiable when the uncertainty in investment costs is considered, can be determined by the net revenue which becomes a fuzzy interval (subtraction of the fuzzy variables ΔIC and ΔI). ΔNR for alternative 2 and 3 are given in Fig. 8.25.

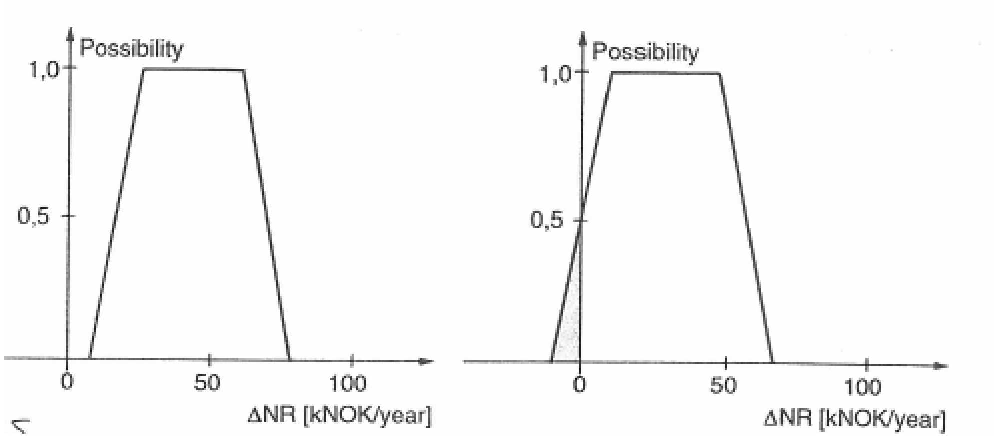


Fig. 8.25 Membership functions for the net revenue ΔNR (*corrected*).

The alternatives are justifiable in socio-economic terms when ΔNR is positive. For both alternatives there is a small part of the membership which is negative. The positive portion can be evaluated by the area criterion [78]. The relative area A_{II} in the figure, can be taken as a degree of certainty where $\Delta NR > 0$. The degree of certainty is highly significant for both alternatives in this example.

Summary of results:

The resulting time variation has non-significant influence on the total EIC for the distribution system. The traditional method gives practically the same annual costs when the annual average specific cost is used, while using the reference cost underestimates EIC by 29 %. In this case the traditional method significantly underestimates EPNS and EENS (by 19 % and 24 % respectively), partly due to some relatively high correction factors for the residential loads.

Installation of circuit breaker or a new cable, thus splitting the network in an overhead radial and an underground cable radial, leads to considerable reliability improvements especially in the cable network. For instance is the total EIC reduced by approx. 70 %. The cost-benefit analysis shows that both alternatives are cost-effective. The benefit (reduction in EIC) achieved by either of the two alternatives is practically equal. As such the installation of the circuit breaker is the theoretically optimal solution since this represents the cheapest investment.

The inclusion of uncertainty in interruption costs and investment costs does not alter the conclusions concerning the two alternative reinforcements, neither with respect to cost-effectiveness nor optimality. The results and conclusions are quite obvious in this case due to the characteristics of the problem with the combined supply to an underground cable network and an overhead network. The installation of a circuit breaker is a relatively cheap investment which makes considerable improvements in the interruption conditions to the delivery points supplied by underground cable. Dividing the network in an overhead part and a cable part, gives considerable improvements in the whole network. This alternative is however more expensive. Both alternatives are nevertheless cost-effective.

The fuzzy descriptions used in this decision problem are examples of how to explore the possible influence uncertainty might have on decision variables.

9 Discussion and conclusions

This chapter gives a summary of the basic objectives for the thesis and a discussion of the models and methods developed in relation to the main issues studied. The main conclusions from the thesis are summarized, and some recommendations for further work are given.

- All models are wrong - some are useful
George E. P. Box

9.1 Main focus of the thesis

The main objective of this research work has been to develop models and methods for estimation of annual interruption costs for delivery points. Recent customer surveys on interruption costs provide better estimates of costs per interruption and more information on the characteristics of these costs, thereby motivating further studies of the annual costs. This is relevant as there is increased interest in the quality of power supply both from the customers and the regulation authorities. This calls for improved methods for assessment of interruption costs for delivery points at any system level.

The surveys show that the cost per interruption has a considerable variation depending on the time of occurrence. Analyses of available data from failure statistics show similar time variations in failures and repair time on a daily, weekly and monthly basis. The time dependent patterns indicate that there is a time dependent correlation between the variables that might influence the annual costs. How can this time variation be represented in calculation models for annual interruption costs, and has it a significant impact?

There are also stochastic variations in the variables that determine the annual interruption costs, as well as other types of uncertainties, termed fuzziness in this thesis. Models describing the dispersions and uncertainties in the annual costs are required to provide more credible results as a basis for optimization of the reliability level. This work has aimed at combining the representation of time variations and the additional uncertainties in the variables and to show how these mechanisms may affect the reliability indices, particularly power not supplied (PNS), energy not supplied (ENS) and annual interruption costs (IC).

The main contributions from this thesis are practical models and methods to compute these indices with emphasis on the handling of time dependent patterns and uncertainties in the input variables.

9.2 The main issues

In general the study has brought deeper insight into the problem of assessing *annual* interruption costs, and the application of cost estimates from customer surveys in particular. The connections between the different variables are rather complex and call for a careful use of the data. This section gives a brief discussion of the models and methods developed in relation to the main issues studied in the thesis.

9.2.1 Practical models and methods

The main results of the work are improved methods for estimation of annual interruption costs (IC) for delivery points. The generalized models are independent of power system level and can be applied to any transmission or distribution system. The focus has been to develop practical models and methods for planning purposes. The methods are therefore based on typical data that are available from failure statistics, load registrations and customer surveys on interruption costs.

The methods start with a list of outage events which may lead to interruptions in the delivery point. It is assumed that these outage events are predetermined by appropriate methods for load flow and contingency analyses. Highly developed methods are available for contingency selection and ranking, these are both Monte Carlo and analytical methods, and they can be used as a basis for the developed methods. This approach allows the reliability assessment to be decoupled from time-consuming load flow analyses, and thereby simplifies the process of determining the annual interruption costs.

IC is found by summation of the contributions from the individual outage events. The methods give in addition the most common reliability indices in use, such as annual interruption time, PNS and ENS.

Radial systems

The analytical method developed for radial systems makes use of correction factors in conjunction with traditional reliability models for radial systems, to handle the time variation in the variables. The idea is to precalculate such factors for a certain area or, in more detail, for different types of components and delivery points in a particular system. The calculation of correction factors requires relative time profiles for components and loads.

Reliability and cost assessment is simple from an analytical point of view, but the calculation method requires comprehensive information and “book-keeping” of data and results due to the large number of components and delivery points, especially in MV distribution systems. The use of such precalculated factors to incorporate the time variation in input variables, however, provides a practical method for radial systems. If it is possible to establish relative time profiles for different types of components, correction factors may be calculated for combinations of loads, customers and components. This is a rather comprehensive task, but it can be performed once and the factors updated when new data are available.

Meshed systems

Such correction factors cannot be applied to meshed systems, since they are based on a total interruption of load for each failure. In meshed systems interruptions only occur when the load exceeds the available capacity to supply the load. Each outage event is therefore analysed in detail, and contributions to interruptions from each time period are calculated sequentially (in the analytical method). Thus, the method is highly time-consuming compared with the analytical method for radial systems.

A typical transmission problem is to look at a few delivery points or a local area. Contingency screening and ranking usually narrows the event space to a few critical events, such that the data needed about components and loads will be limited compared with a distribution system problem.

The analytical method for meshed systems may be used to study the influence of the time dependency between the specific cost and the duration also in radial systems, especially for delivery points with nonlinear cost functions.

Towards practical applications

The methods developed in this work are available as prototypes. These prototypes are used to provide the illustrations of the methods in Chapter 7 as well as the examples on applications in transmission and distribution systems in Chapter 8. The methods can be implemented in existing tools for reliability assessment with the necessary extensions of models and data bases needed for different purposes. To encourage further practical applications the methods should be implemented in user-friendly tools.

The prototypes include some simplifications and limitations that should be eliminated for practical applications:

The calculation of energy not supplied for each interruption is simplified. System Available Capacity and Local Generation are considered to be constants and neither represented as functions of time nor as stochastic variables, and maintenance is not modelled.

The models and methods can be extended to incorporate a procedure for selective disconnection of loads according to a classification in critical and less critical loads etc. Other extensions such as a discrimination between costs for short (≤ 3 minutes) and long interruptions (> 3 minutes) is also possible. A proposed procedure for this in connection with the method for radial systems is described in Appendix 3.

The methods are based on a constant *annual* failure rate λ (on average) assuming that the annual number of failures is Poisson distributed. If the average failure rate is assumed to increase during the period of analysis for a given system solution, this can be considered using a different average failure rate in different sub-periods.

According to the discussion in Chapter 2, there is a question of validity (or stationarity) of the specific cost estimates in the future. The specific cost is expected to increase in the future due to increased utilization of and dependence on electricity. For decision problems involving a period of analysis, the variable cost IC will have to be determined for each year in the period, taking increasing load year by year into consideration. The aspect of stationarity of the cost estimates should be considered in such applications.

9.2.2 Handling of uncertainties

Planning of power systems are mostly based on expectation values. A description which incorporates uncertainties in input variables and shows the influence on the outputs will become more important for future decisions as reliability cost/worth considerations are becoming an operational tool. Uncertainties in the reliability indices may be described by confidence intervals, according to classical methods.

The Monte Carlo simulation model that incorporates the stochastic variations in input variables, provides the additional dispersions in reliability indices. This information can be used to investigate the probabilities of getting values lower or higher than certain figures, for instance according to reliability constraints. For particular customers or delivery points this kind of information may be of high importance.

The method can be used to study the influence of different probability distributions as well as the combined effect of time variation and stochastic variations on the reliability indices. In particular if the cost function is nonlinear, the Monte Carlo method will give a more accurate expectation of IC than the analytical methods. This is due to the method's ability to handle the time dependency between the specific cost and the duration of interruptions also in the stochastic variations.

For some of the variables determining the annual costs there may be little if no information available. In such cases uncertainties (fuzziness) in input variables cannot be estimated from observations of the variables. The fuzziness can be given a qualitative description and the variables represented by a fuzzy description using the procedure described in this thesis. The procedure provides the uncertainties in the reliability indices by membership functions. The functions directly visualize the upper and lower bounds (or intervals) for the reliability indices. The fuzzy description is illustrated for radial systems.

These kinds of uncertainties might as well be represented by probability distributions, assigning *subjective* distributions to the variables. In that case the probability distributions of the reliability indices could be found in the traditional way using Monte Carlo simulation. The distributions do not give the upper and lower bounds directly, but statistics such as standard deviations and percentiles may be calculated.

An advantage of a fuzzy representation is the simplicity of calculation techniques, which makes the equations analytically solvable. Another advantage is the simple interpretation of the results. The memberships represent a quantification of the possibilities of outcomes, which is intuitively understandable. For a fuzzy representation to become a practical tool however, this approach should be further investigated and compared with the traditional representation of uncertainties.

The different variables could be investigated according to uncertainties to determine which variables are most fuzzy, if the uncertainty can be estimated from observations or if a qualitative description is more appropriate and so on. For instance, the specific cost may be a fuzzy variable by nature, and future load forecasts may be very uncertain even if typical loads are well defined.

9.2.3 Representation of time-varying failure rate

The time-varying failure rate is represented in the developed methods by average cyclic variations based on observations of all types of failures, i.e., failures caused by climatical, technical and other causes (such as human). A description of these accumulated effects registered in the failure statistics is primarily suitable for the determination of expected variations in the long run. This makes use of the total number of failures observed for different types of components. The chosen representation is found suitable for estimation of annual interruption costs in the long run, i.e., for planning purposes. The advantage of this representation is that it requires less data than the classical weather-state description where the failure rate is determined by the weather in different periods.

Weather dependent failure rates differ for different types of components, and the types of climatic exposures vary for different geographical areas. Overhead lines may be heavily exposed to weather, while underground cables are more exposed to other activities such as digging. A classical weather-based description counts only for climatic conditions, which may be suitable for outdoor components exposed to weather. It makes use of both failure statistics and weather information. A comprehensive amount of information is required to predict the weather state and to provide failure rates and repair times for different types of weather. Such models may be very useful in the operating phase and in short term considerations of reliability and interruption costs, due to their ability of predicting the weather-dependency.

In the aggregate model it is assumed that all types of failures vary with time, and the failures are put into a single variable. In a weather-based model other types of failures may be grouped in the variable describing the normal weather state. These types of failures are in the classical methods assumed to have a constant failure rate, which means that the variations in the total failure rate are determined by the weather only. The two aspects might be combined in a description in two parts to provide combined models for the operating and planning phase:

- A prediction of weather states and representation of a weather-dependent failure rate
- A description of other types of failures by average cyclic variations, representing a time-varying failure rate.

9.2.4 Time dependent correlation

The models and methods developed are illustrated using examples of available data from failures statistics, load registrations and customer surveys, both for a simple example and for real cases from the transmission and distribution system. Correlation factors are calculated using examples of data for a one-shift industrial load and a commercial load, together with 6-year failure statistics for distribution systems, and interruption cost data for the major industrial and commercial sectors.

These examples show that the time dependent correlation may be significant for certain combinations of variables in the distribution system. The correlation is particularly significant on a weekly and daily basis. The resulting correlation based on these limited data is however found non-significant for the annual interruption cost. This conclusion is based on the use of average specific costs (on an annual basis) as input in the comparison with the traditional method. The influence may however be more significant for expected power and energy not supplied.

The method for radial systems may be used to study the influence of time dependent correlation. The correction factors reflect the impact of the time dependent correlation on the annual reliability indices. It is recommended that comprehensive data analysis and calculation of correction factors are performed on a general basis to investigate this influence. If the influence is found to be significant, it may be justifiable to pay the extra effort in calculating such correction factors on a wide basis for a diversified number of combinations. If however the time dependent correlation is found to be non-significant for the reliability indices in the general case, it is recommended to use the traditional analytical method for radial systems, but with the *average* specific cost function on an annual basis.

In meshed systems the time varying failure rate may be of high importance for the occurrence of *interruptions* at the delivery point due to increased failure rate in periods where the load is high. The examples show that time dependent (cyclical) patterns on a weekly and daily basis may have a significant influence on IC as well as other indices. It is therefore recommended to analyse the failure statistics on the higher system levels for such patterns, to investigate this influence. If there is no characteristic time dependent pattern in failures and repair time, representation of the input variables can be simplified, i.e. less data are required for each outage event without losing significant accuracy in reliability indices. In that case time variation in the specific cost should be taken care of using the *average* specific cost function as for radial systems.

9.2.5 Application of specific interruption cost

In the developed methods the cost per interruption is represented as a specific (normalized) cost. The application of specific interruption costs is found to be a rather complex task, especially taking time variation in interruption costs into account.

In this study data from the Norwegian survey is used. The specific costs are here referred to the *energy not supplied* at the reference time. This seems at first a good idea since the annual costs traditionally are determined by the product of energy not supplied and the specific cost. Both the Norwegian and other surveys have shown that there may be a significant variation in the cost per interruption with time of the day, day of the week and month of the year. The corresponding time variation in the specific cost depends on the time variation in the load *in addition* to the cost per interruption. This complicates the representation of time dependency and probably introduces more uncertainty about the specific cost.

The problem might be avoided by first recalculate the cost per interruption for a given duration and use the corresponding time variation. The methods would then have to be based on the cost per interruption instead of the product of a volume and a specific cost. A proposed model based on the cost per interruption is described Chapter 6.

9.3 Conclusions and further work

The main conclusions from the thesis are summarized as follows:

- **Improved methods for estimation of annual interruption costs**
  The contributions from the work have provided an improved basis for decisions related to reliability cost/worth. This will enable the socio-economic costs of power supply interruptions to be determined more correctly both according to expectation values and uncertainties. Consequently more credible estimates of this cost element can be provided as a basis for the optimization of the power system.

- **Uncertainties can be handled**
  Uncertainties in input variables can be handled either by a Monte Carlo simulation giving probability distributions and confidence intervals for the reliability indices or by a fuzzy description giving the degree of fuzziness in the indices, represented by fuzzy memberships and intervals. Both methods give valuable additional information.

- **<u>Careful modelling necessary</u>**
  This work has shown that application of a *normalized* cost at a *reference* time may lead to significant underestimation of annual costs, i.e., when the normalization factor is *energy not supplied*. If a detailed time variation in the variables is not represented, the time variation in the specific cost should be considered using the specific cost function on an annual *average*.

- **<u>Correlation: More studies needed</u>**
  Examples in this thesis show that the time dependent correlation may be significant for certain combinations of input variables. The correlation is particularly significant on a weekly and daily basis. Time variation may have a significant impact on annual reliability indices in transmission systems, due to the considerable importance of the time varying failure rate for the occurrence of *interruptions*. For distribution systems, however, the resulting correlation is not found significant for the annual interruption cost in these examples. This conclusion is based on limited data and more studies are needed for radial and meshed systems to investigate the influence of the time variation on the annual indices.

Recommendations for further work concentrate on the following four aspects:

- **<u>Practical applications</u>**
  The methods developed in this thesis can be implemented in existing tools for reliability assessment. To encourage further practical applications it is recommended that the prototyped methods are implemented in user-friendly tools.

- **<u>Description of uncertainties</u>**
  A fuzzy description of uncertainties may prove to be very useful. For a fuzzy representation to become a practical tool however, it is necessary to explore results in accordance with practical applications. This approach should be further investigated and compared with the traditional representation of uncertainties.

- **<u>Combined methods for operating and planning phases</u>**
  It is proposed to investigate if the classical weather-based description and the average cyclic description of the time-varying failure rate can be combined to possibly provide combined models and tools for the operating and planning phases.

- **<u>Methods based on cost per interruption</u>**
  It is recommended to investigate if methods based on the cost per interruption may lead to improvements compared to methods based on specific costs, especially taking time variation in input variables into account.

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Appendix 1

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Appendix 2

Estimation of covariance and correlation

A2.1 Covariance and correlation

Let X and Y be two stochastic variables. The *covariance* of X and Y is defined by:

$$\begin{aligned} Cov(X,Y) &= E[(X - E(X))(Y - E(Y))] \\ &= E(XY) - E(X)E(Y) \end{aligned} \tag{A2.1}$$

where E(X) and E(Y) are the expectations of X and Y respectively. If X and Y are independent, then E(XY) = E(X)E(Y), and the covariance is zero. Reversely, if the covariance is zero, the variables X and Y are not necessarily independent. In that case X and Y have a random variation according to each other.

If the covariance is positive, X and Y are positively correlated, which means that maximum values or minimum values of X and Y tend to occur at the same time.

If the covariance is negative, X and Y are negatively correlated, which means that minimum of X and maximum of Y or vice versa, tend to occur at the same time.

The *correlation* between X and Y is defined by:

$$\rho(X,Y) = \frac{Cov(X,Y)}{\sqrt{Var(X)Var(Y)}} = \frac{Cov(X,Y)}{SD(X)SD(Y)} \tag{A2.2}$$

where SD(X) and SD(Y) are the standard deviations of X and Y respectively. $\rho(X,Y)$ is denoted the correlation factor. The correlation factor is independent of measurement scales, and therefore:

$$-1 \le \rho(X,Y) \le +1 \tag{A2.3}$$

If X and Y are independent, $\rho(X,Y)=0$.

A2.2 Expectation

Let X and Y be represented by ‘n’ pairwise observations, $(x_i,y_i) = (x(t_i),y(t_i))$:

$$\begin{aligned} \underline{X} &= [\, x_1, x_2, \ldots\ldots, x_n \,] \\ \underline{Y} &= [\, y_1, y_2, \ldots\ldots, y_n \,] \end{aligned} \tag{A2.4}$$

The expectations of X and Y can be estimated by:

$$E(X) = \frac{1}{n}\sum_{i=1}^{n} x_i$$
$$E(Y) = \frac{1}{n}\sum_{i=1}^{n} y_i \qquad \text{(A2.5)}$$

Consider the variable Z = XY. The target is to estimate the expectation of Z, i.e. E(XY), while considering the time dependency between $X(t_i)$ and $Y(t_i)$. From Eq. (A2.1) we have an expression of E(XY):

$$E(XY) = Cov(X,Y) + E(X)E(Y) \qquad \text{(A2.6)}$$

To estimate E(XY), we need an estimate of Cov(X,Y). This estimate can be found by using the definition of the covariance in Eq. (A2.1), the ‘n’ observations of X and Y, and the estimates of E(X) and E(Y) from Eq. (A2.5):

$$Cov(X,Y) = \frac{1}{n}\sum_{i=1}^{n} [(x_i - E(X))(y_i - E(Y))]$$
$$= \frac{1}{n}\sum_{i=1}^{n} x_i y_i - \frac{1}{n}\sum_{i=1}^{n} x_i E(Y) - \frac{1}{n}\sum_{i=1}^{n} y_i E(X) + E(X)E(Y) \qquad \text{(A2.7)}$$
$$= \frac{1}{n}\sum_{i=1}^{n} x_i y_i - E(X)E(Y)$$

A comparison of Eqs. (A2.6) and (A2.7) gives the seeked estimate of E(XY):

$$E(XY) = \frac{1}{n}\sum_{i=1}^{n} x_i y_i = \frac{1}{n}\sum_{i=1}^{n} x(t_i)y(t_i) \qquad \text{(A2.8)}$$

The expectation of the product of two stochastic variables X and Y can thus be estimated by multiplying the pairwise observations at the points t_1, t_2, ..., t_n, and by taking the average of these sub-products.

The formula Eq. (A2.8) can easily be extended to several variables.

Appendix 3

Expectation method for radial systems

This appendix gives a detailed description of the expectation method for radial systems described in Ch. 6. The results from Appendix 2 for the estimation of expectation of products between stochastic variables, are applied here to the assessment of annual interruption time, expected power not supplied, expected energy not supplied and annual expected interruption costs. The deduction is based on the formulas presented in Chapter 3 for radial systems.

A3.1 Introduction

The target is to estimate the annual expected interruption costs (EIC), while considering the time dependent correlation between the variables for daily, weekly and monthly variation. The expected annual costs are given a general formulation in Chapter 5, Eq. (5.14):

$$EIC = E(\lambda Pr\, c_W) \tag{A3.1}$$

By using Eq. (A2.8) for the estimation of an expected product of stochastic variables, this can in general be expressed as

$$E(\lambda Pr\, c_W) = \frac{1}{n}\sum_{i=1}^{n}\Big(\sum_{j=1}^{N_i} P(t_j) r(t_j) c_W(r(t_j))\Big)_i \tag{A3.2}$$

The different elements in Eq. (A3.2) are interpreted in the following:

n = Number of years considered
N_i = Number of interruptions in year no 'i'
t_j = Time of interruption no. 'j' = $(h, d, m)_j$
$P(t_j)$ = Expected load when the interruption occurs at t_j
$r(t_j)$ = Expected duration when the interruption occurs at t_j
$c_W(r(t_j))$ = Expected interruption cost when the interruption occurs at t_j, with duration $r(t_j)$.

The product of $P(t_j)$ and $r(t_j)$ in the equation will result in energy not supplied (ENS). In general ENS is determined by the integration of the load curve in the time period $r(t_j)$ (see Ch. 3):

$$ENS_j = \int_{r_j} P(t)dt \tag{A3.3}$$

$P(t_j)$ should therefore be interpreted as the *expected load in the time period $r(t_j)$*, when the interruption occurs at t_j.

The expected costs in Eq. (A3.2) represent the annual costs in the long run. $P(t_j)$, $r(t_j)$ and $c_W(t_j)$ are pairwise observations at the time of interruptions t_j, and they are expectation values at

t_j. The number of interruptions per year, N_i, is determined by simulating failures on the components involved in the system solution under study.

The time of occurrence of interruptions and the pairwise expectation values are determined in the following way (see Chapters 4 and 5):

A year is divided into time units according to the typical cyclic load variations on monthly, weekly and daily basis:

- monthly variation, 12 values (per year)
- weekly variation, 7 values (per year)
- daily variation, 24 values (per year)

giving 12·7·24 = 2016 time units.

The expected number of failures at a specific time is given by the proportion of the average *annual* number of failures occuring in the particular hour (h), weekday (d) or month (m):

$$q_{\lambda h} = \frac{\lambda_h}{\lambda_{av}} = \frac{\lambda_h}{\sum \lambda_h}, \sum q_{\lambda h} = 1.0$$
$$q_{\lambda d} = \frac{\lambda_d}{\lambda_{av}} = \frac{\lambda_d}{\sum \lambda_d}, \sum q_{\lambda d} = 1.0 \qquad \text{(A3.4)}$$
$$q_{\lambda m} = \frac{\lambda_m}{\lambda_{av}} = \frac{\lambda_m}{\sum \lambda_m}, \sum q_{\lambda m} = 1.0$$

such that

$$\lambda_{h,d,m} = \frac{\lambda_h}{\lambda_{av}} \frac{\lambda_d}{\lambda_{av}} \frac{\lambda_m}{\lambda_{av}} \lambda_{av} \qquad \text{(A3.5)}$$

where λ_{av} is the annual average number of failures. The relative failure rates 'q_λ' in Eq. (A3.4) are interpreted as the conditional probabilities of having failures in hour (h), weekday (d) and month (m) respectively, see Chapter 5.

Eq. (A3.5) represents the expected number of failures in the long run, i.e. an average for the period considered. The number of years 'n' and the number of interruptions 'N_i' in Eq. (A3.2) are thus replaced by the annual average number of failures λ_{av} and the average q_λ-factors.

As an example in the following sections it is chosen to represent the variables by their expected monthly variation, i.e., by 12 observations per year. Let the number of interruptions (which is determined by the total failure rate in radial systems) be represented by 12 monthly values describing the seasonal variation in failures:

$$\underline{\lambda} = [\, \lambda_1, \lambda_2, \ldots\ldots., \lambda_{12} \,] \tag{A3.6}$$

The observations are further described by relative figures, given by their portion of the annual failure rate:

$$q_{\lambda m} = \frac{\lambda_m}{\sum_{m=1}^{12} \lambda_m}\ , \quad \sum_{m=1}^{12} q_{\lambda m} = 1.0 \tag{A3.7}$$

$$\underline{\lambda} = \lambda_{av} [\, q_{\lambda 1}, q_{\lambda 2}, \ldots\ldots., q_{\lambda 12} \,] \tag{A3.8}$$

This gives

A3.2 Estimation of annual expected power not supplied

For the estimation of annual expected power not supplied E(λP), the load is also represented by the expected monthly variation:

$$\underline{P} = [\, P_1, P_2, \ldots\ldots., P_{12} \,] \tag{A3.9}$$

These observations are described by relative figures. The load is referred to the annual expected load P_{av}. The monthly load factors are then (see Ch. 5):

$$k_{pm} = \frac{P_m}{P_{av}} \tag{A3.10}$$

and

$$\underline{P} = P_{av} [\, k_{p1}, k_{p2}, \ldots\ldots., k_{p12} \,] \tag{A3.11}$$

Now using Eqs. (A2.8) and (A2.11) and considering one year, we get:

$$\begin{aligned} E(\lambda P) &= \sum_{m=1}^{12} \lambda(t_m) P(t_m) \\ &= \sum_{m=1}^{12} \lambda_{av} q_{\lambda m} P_{av} k_{pm} \\ &= \lambda_{av} P_{av} \sum_{m=1}^{12} q_{\lambda m} k_{pm} \\ &= \lambda_{av} P_{av} k_{\lambda Pm} \end{aligned} \tag{A3.12}$$

Since the sum of the $q_{\lambda m}$-factors is equal to 1.0, Eq. (A3.12) will give the *annual* expectation. The correction factor $k_{\lambda Pm}$ includes the *time dependent correlation* between P and λ in addition to the relative deviation from the reference values.

For comparison with the traditional analytical method, which multiplies the expectation values of the variables involved, the difference is the covariance (Eq. (A2.1)):

$$Cov(\lambda, P) = E(\lambda P) - \lambda_{av} P_{av} = \lambda_{av} P_{av} (k_{\lambda Pm} - 1) \tag{A3.13}$$

A3.3 Estimation of annual expected energy not supplied

The estimation of expected energy not supplied (EENS) introduces another variable: The interruption time, which is determined by repair of failed component or restoration of supply by switching activities. Similarly to the failure rate and the load, the interruption time 'r' can be represented by its relative monthly variation:

$$\underline{r} = r_{av} [k_{r1}, k_{r2}, \ldots\ldots, k_{rm}] \tag{A3.14}$$

where the monthly variation is referred to the annual expectation (estimated from 12 observations).

EENS can hence be estimated, using Eqs. (A2.8) and (A3.2) with three variables:

$$
\begin{aligned}
E(\lambda Pr) &= \sum_{m=1}^{12} \lambda(t_m) P(t_m) r(t_m) \\
&= \sum_{m=1}^{12} \lambda_{av} q_{\lambda m} P_{av} k_{pm} r_{av} k_{rm} \\
&= \lambda_{av} P_{av} r_{av} \sum_{m=1}^{12} q_{\lambda m} k_{pm} k_{rm} \\
&= \lambda_{av} P_{av} r_{av} k_{\lambda Prm}
\end{aligned}
\qquad \text{(A3.15)}
$$

The *correction* factor $k_{\lambda Prm}$ is:

$$k_{\lambda Prm} = \sum_{m=1}^{12} q_{\lambda m} k_{pm} k_{rm} \qquad \text{(A3.16)}$$

The difference between Eq. (A3.15) and the traditional method is the covariance:

$$Cov(\lambda, P, r) = E(\lambda Pr) - \lambda_{av} P_{av} r_{av} = \lambda_{av} P_{av} r_{av} (k_{\lambda Prm} - 1) \qquad \text{(A3.17)}$$

A3.4 Estimation of annual expected interruption costs

The third example considers the estimation of the annual expected interruption costs (EIC), formulated in Eqs. (A3.1) and (A3.2). This involves the time correlation in 4 variables, the fourth variable being the specific interruption cost c_W.

The interruption cost is represented by its relative monthly variation. The reference value is chosen as the estimated value at the *reference time* used in customer surveys:

$$\underline{c_W} = c_{Wref} [k_{c1}, k_{c2}, \ldots\ldots, k_{cm}] \qquad \text{(A3.18)}$$

The expectation can now be found in a similar way as the expected power- and energy not supplied not supplied above:

$$E(\lambda Pr\, c_W) = \sum_{m=1}^{12} \lambda(t_m) P(t_m) r(t_m) c_W(t_m)$$
$$= \sum_{m=1}^{12} \lambda_{av}\, q_{\lambda m}\, P_{av}\, k_{pm}\, r_{av}\, k_{rm}\, c_{Wref}\, k_{cm} \tag{A3.19}$$
$$= \lambda_{av}\, P_{av}\, r_{av}\, c_{Wref}\, k_{\lambda Prcm}$$

where c_{Wref} is the expected interruption cost referred to a reference time for average duration 'r', and the *correction* factor $k_{\lambda Prcm}$ is:

$$k_{\lambda Prcm} = \sum_{m=1}^{12} q_{\lambda m}\, k_{pm}\, k_{rm}\, k_{cm} \tag{A3.20}$$

It should be noted here that Eq. (A3.19) gives a general formulation of the problem. The formula does not include the varying duration from interruption to interruption.

A3.5 Correction factors

The previous deduction has given formulas for correction factors for monthly variation, Eqs. (A3.16) and (A3.20). These factors can be precalculated for a certain area, based on expected monthly variation of the parameters. The precalculated correction factors contain the time dependency (or time dependent correlation) among the variables.

Typical expected time profiles are shown in Chapter 4, for daily, weekly and monthly variation. The daily and weekly variation can be taken care of in the same way as the monthly. For daily variation each variable is represented by 24 observations, as shown in Ch. 4. The annual failure rate is now divided in 24 portions, to determine the factors $q_{\lambda h}$ (cfr. Eq. (A3.4)).

For the weekly variation the variables are represented by 7 observations each, and the annual failure rate is divided in 7 portions, giving the factors $q_{\lambda d}$ (cfr. Eq. (A3.4)). Factors considering daily, weekly and monthly variations are summed up in the following, and finally the resulting annual factors are presented.

A3.5.1 Daily variation

$$
\begin{aligned}
k_{\lambda rh} &= \sum_{h=1}^{24} q_{\lambda h} k_{rh} \\
k_{\lambda Ph} &= \sum_{h=1}^{24} q_{\lambda h} k_{ph} \\
k_{\lambda Prh} &= \sum_{h=1}^{24} q_{\lambda h} k_{ph} k_{rh} \\
k_{\lambda Pch} &= \sum_{h=1}^{24} q_{\lambda h} k_{ph} k_{ch} \\
k_{\lambda Prch} &= \sum_{h=1}^{24} q_{\lambda h} k_{ph} k_{rh} k_{ch}
\end{aligned}
\tag{A3.21}
$$

A3.5.2 Weekly variation

$$
\begin{aligned}
k_{\lambda rd} &= \sum_{d=1}^{7} q_{\lambda d} k_{rd} \\
k_{\lambda Pd} &= \sum_{d=1}^{7} q_{\lambda d} k_{pd} \\
k_{\lambda Prd} &= \sum_{d=1}^{7} q_{\lambda d} k_{pd} k_{rd} \\
k_{\lambda Pcd} &= \sum_{d=1}^{7} q_{\lambda d} k_{pd} k_{cd} \\
k_{\lambda Prcd} &= \sum_{d=1}^{7} q_{\lambda d} k_{pd} k_{rd} k_{cd}
\end{aligned}
\tag{A3.22}
$$

A3.5.3 Monthly variation

$$
\begin{aligned}
k_{\lambda rm} &= \sum_{m=1}^{12} q_{\lambda m} k_{rm} \\
k_{\lambda Pm} &= \sum_{m=1}^{12} q_{\lambda m} k_{pm} \\
k_{\lambda Prm} &= \sum_{m=1}^{12} q_{\lambda m} k_{pm} k_{rm} \\
k_{\lambda Pcm} &= \sum_{m=1}^{12} q_{\lambda m} k_{pm} k_{cm} \\
k_{\lambda Prcm} &= \sum_{m=1}^{12} q_{\lambda m} k_{pm} k_{rm} k_{cm}
\end{aligned}
\tag{A3.23}
$$

The correction factor $k_{\lambda r}$ includes the time dependent correlation between failures and duration, for the calculation of annual interruption time U. Eqs. (A3.21 - A3.23) contain a factor $k_{\lambda Pc}$. This factor is for calculation of annual costs for short interruptions as will be explained in Section A3.6.

A3.5.4 Annual correction factors

The day-, week- and month-factors can be combined to get annual correction factors which includes the three types of variation in the variables. Since the annual failure rate λ each time is divided in portions in accordance with the number of observations (time periods) used, the annual factors are determined combining Eqs. (A3.21) - (A3.23):

Correction factor for the assessment of annual interruption time U:

$$k_{\lambda r} = k_{\lambda rh} k_{\lambda rd} k_{\lambda rm} \quad \text{(A3.24)}$$

Correction factor for the assessment of annual expected power not supplied EPNS:

$$k_{\lambda P} = k_{\lambda Ph} k_{\lambda Pd} k_{\lambda Pm} \quad \text{(A3.25)}$$

Correction factor for the assessment of annual expected energy not supplied EENS:

$$k_{\lambda Pr} = k_{\lambda Prh} k_{\lambda Prd} k_{\lambda Prm} \quad \text{(A3.26)}$$

Correction factors for the assessment of annual expected interruption costs EIC:

$$\begin{aligned} k_{\lambda Pc} &= k_{\lambda Pch} k_{\lambda Pcd} k_{\lambda Pcm} \\ k_{\lambda Prc} &= k_{\lambda Prch} k_{\lambda Prcd} k_{\lambda Prcm} \end{aligned} \quad \text{(A3.27)}$$

The factors in Eqs. (A3.24) - (A3.27) can thus be determined by calculating the contribution from daily, weekly and monthly variation separately. One should keep in mind that in the relative daily load factor k_{ph}, the load is referred to P_{max}, while the load on a weekly and monthly basis is referred to P_{av}. The expected failure rate at a specific time is given in Eq. (A3.5). Expectation values for the load, repair time and specific cost in a particular hour (h), weekday (d) and month (m) are, from Chapter 5:

$$P_{h,d,m} = \frac{P_h}{P_{\max}} \frac{P_d}{P_{av}} \frac{P_m}{P_{av}} P_{\max} \tag{A3.28}$$

$$r_{h,d,m} = \frac{r_h}{r_{av}} \frac{r_d}{r_{av}} \frac{r_m}{r_{av}} r_{av} \tag{A3.29}$$

$$c_{W\,h,d,m} = \frac{c_{Wh}}{c_{Wref}} \frac{c_{Wd}}{c_{Wref}} \frac{c_{Wm}}{c_{Wref}} c_{Wref} \tag{A3.30}$$

If we apply Eqs. (A3.5) and (A3.28 - A3.30) to Eq. (A3.2), i.e., replace n and N_i by $\lambda_{h,d,m}$, we get a generalized version of Eq. (A3.19).

$$\begin{aligned} E(\lambda P r c_W) &= \frac{1}{n}\sum_{i=1}^{n}\Big(\sum_{j=1}^{N_i} P(t_j) r(tsubj) c_W(r(t_j))\Big)_i \\ &= \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} \lambda_{h,d,m} P_{h,d,m} r_{h,d,m} c_{W\,h,d,m} \\ &= \lambda_{av} P_{\max} r_{av} c_{Wref} \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h} q_{\lambda d} q_{\lambda m} k_{ph} k_{pd} k_{pm} k_{rh} k_{rd} k_{rm} k_{ch} k_{cd} k_{cm} \\ &= \lambda_{av} P_{\max} r_{av} c_{Wref} k_{\lambda Prc} \end{aligned} \tag{A3.31}$$

In the generalized formulation of EIC in Eq. (A3.31), the reference value for the load is P_{max}, which means that the total correction factor $k_{\lambda Prc}$ is referred to the maximum load, according to Eq. (A3.28). The difference between formulas Eqs. (A3.19) and (A3.31) is that in the first formula, only the monthly variation in the variables is considered, giving different reference value for the load, according to Eq. (A3.28).

The covariance is now

$$\begin{aligned} Cov(\lambda,P,r,c) &= E(\lambda Prc) - \lambda_{av} P_{av} r_{av} c_{Wav} \\ &= \lambda_{av} P_{av} r_{av} c_{Wav}\Big(\frac{P_{\max}}{P_{av}} \frac{c_{Wref}}{c_{Wav}} k_{\lambda Prc} - 1\Big) \end{aligned} \tag{A3.32}$$

The total annual correction factor $k_{\lambda Prc}$ will be less than, equal to or greater than 1.0, depending on the choice of reference figures.

A3.6 Practical calculation method

The aim of the deduction of ‘correction factors’ in this appendix has been to provide a practical expectation method while considering the time dependent correlation between the variables. The time variation can be represented by expected time profiles of the variables involved. Thus the correction factors can be precalculated for a certain area based on such expected time profiles. Calculation of the factors is described in Section A3.7. As the formulas in the previous sections show, the correction factors can be used in conjunction with the simple expectation method presented in Chapter 3.

By referring the factors to some known (or easily derived) reference values, the formulas presented in this appendix give a practical approach to the assessment of annual expectation values for annual interruption time, power not supplied, energy not supplied and interruption costs.

As already mentioned, the expectations in Eqs. (A3.12), (A3.15), (A3.19) and (A3.31) are primarily general representations, according to a radial model. In this section a more practical approach is presented, based on the reference figures used above and the resulting correction factors in Eqs. (A3.24 - A3.27).

The method is based on *simulation of failures* on the components in the supply network using the analytical model RELRAD described in Appendix 1.

A general delivery point with a single customer is considered.

A3.6.1 Estimation of annual interruption time

Annual interruption time is given by Eq. (3.8). Including the time dependent correlation between failures and duration this index can be determined in the following way simulating failures on the components in the network:

$$\begin{aligned} U &= \sum_{j=1}^{J} \lambda_j r_j k^*_{\lambda rj} \\ &\approx k_{\lambda r} \sum_{j=1}^{J} \lambda_j r_j \end{aligned} \qquad \text{(A3.33)}$$

where:

J = total number of components giving interruptions to the delivery point
λ_j = failure rate for component no. j
r_j = repair time for component no. j or sectioning time
$k^*_{\lambda rj}$= correction factor for component no. j, calculated from Eq. (A3.24).

A3.6.2 Estimation of power not supplied

The power not supplied can be calculated in the following way

$$\begin{aligned} EPNS &= \sum_{j=1}^{J} \lambda_j P_{\max} k^*_{\lambda P_j} \\ &= P_{\max} \sum_{j=1}^{J} \lambda_j k^*_{\lambda P_j} \\ &\approx P_{\max} k_{\lambda P} \sum_{j=1}^{J} \lambda_j \end{aligned} \qquad \text{(A3.34)}$$

where:

EPNS is annual expected power not supplied
$k^*_{\lambda Pj}$ is the correction factor for component no. j, calculated from Eq. (A3.25).

Notice that in Eqs. (A3.33) and (A3.34) a correction factor per component is introduced. In this way it is possible to use separate precalculated correction factors for overhead lines, cables and so on. The general correction factor for the area, $k_{\lambda r}$ and $k_{\lambda P}$, includes all types of failures and not only the types of components and failures included in the system solution under study. Using the general factor will thus give a less accurate result. Whether it is possible to precalculate factors for different components, depends on the data available.

A3.6.3 Estimation of energy not supplied

Expected energy not supplied (EENS) can be estimated in the same way by simulating failures on the components in the supply network:

$$\begin{aligned} EENS &= \sum_{j=1}^{J} \lambda_j P_{\max} r_j k^*_{\lambda Pr_j} \\ &= P_{\max} \sum_{j=1}^{J} \lambda_j r_j k^*_{\lambda Pr_j} \\ &\approx P_{\max} k_{\lambda Pr} \sum_{j=1}^{J} \lambda_j r_j \end{aligned} \qquad \text{(A3.35)}$$

where:

EENS is annual expected energy not supplied
r_j = repair time or sectioning time
$k^*_{\lambda Prj}$ is the correction factor for failure no. j, calculated from Eq. (A3.26).

Reserve supply facilities are taken care of in the determination of r_j for each failure.

A3.6.4 Estimation of annual interruption costs

Annual interruption costs can be found by first calculating the contribution to energy not supplied from each component or directly using Eq. (A3.31) in a modified form, where the specific cost is represented as a function of duration:

$$
\begin{aligned}
EIC &= \sum_{j=1}^{J} \lambda_j P_{\max} r_j c_{Wref}(r_j) k^*_{\lambda Prc_j} \\
&= P_{\max} \sum_{j=1}^{J} \lambda_j r_j c_{Wref}(r_j) k^*_{\lambda Prc_j} \\
&= P_{\max} \sum_{j=1}^{J} \lambda_j \, c_{Pref}\big(r_j\big) k^*_{\lambda Prc_j} \\
&\approx P_{\max} k_{\lambda Prc} \sum_{j=1}^{J} \lambda_j c_{Pref}(r_j)
\end{aligned}
\qquad (A3.36)
$$

where:

r_j	= repair time for component no. j or sectioning time
$c_{Wref}(r_j)$	= specific interruption cost, reference value NOK/kWh
$c_{Pref}(r_j)$	= specific interruption cost, reference value NOK/kW
$k^*_{\lambda Prcj}$	= resulting correction factor including time dependent correlation between load, failures, interruption time and interruption cost, for component no. j, calculated from Eq. (A3.27).

In Eq. (A3.36) the specific interruption cost is represented in two different ways: $c_{Wref}(r_j)$ is given in NOK/kWh and $c_{Pref}(r_j)$ in NOK/kW. The last representation is often referred to as a Customer Damage Function (CDF), see Chapter 2.

In a two-step approach, the contribution from each component to annual energy not supplied and expected costs are calculated according to the following formula:

$$
\begin{aligned}
&1)\ EENS_j = \lambda_j P_{\max} r_j k^*_{\lambda Pr_j} \\
&\qquad \approx \lambda_j P_{\max} r_j k_{\lambda Pr} \\
&2)\ EIC_j = EENS_j c_{Wref}(r_j) b^*_j \\
&\quad = \lambda_j P_{\max} r_j c_{Wref}(r_j) k^*_{\lambda Pr_j} b^*_j \\
&\quad = \lambda_j P_{\max} c_{Pref}(r_j) k^*_{\lambda Prc_j} \\
&\quad \approx \lambda_j P_{\max} k_{\lambda Prc} c_{Pref}(r_j)
\end{aligned}
\qquad (A3.37)
$$

where:

$EENS_j$	= contribution to expected energy not supplied from component no. ‘j’
EIC_j	= contribution to annual costs from component ‘j’

λ_j	= average failure rate for component 'j'
r_j	= duration in the delivery point caused by component 'j'
$c_{Wref}(r_j)$	= specific cost for duration r_j , reference value (= $c_{Pref}(r_j)/r_j$)
b^*_j	= resulting correction factor, including time dependent correlation between $EENS_j$ and specific interruption cost for the delivery point
$k^*_{\lambda Prj}$	= correction factor for component 'j', calculated from Eq. (A3.26)
$k^*_{\lambda Prcj}$	= correction factor for component 'j' and the delivery point, calculated from Eq. (A3.27).

The factor 'b' in (A3.37) is determined by:

$$b = \frac{k_{\lambda Prc}}{k_{\lambda Pr}} \tag{A3.38}$$

b^*_j for each component determined using Eq. (A3.38) with the component specific k-factors.

The *annual* EENS and EIC for the delivery point can now be expressed by:

$$\begin{aligned} EENS &= \sum_{j=1}^{J} \lambda_j P_{\max} r_j k^*_{\lambda Pr_j} \\ &= P_{\max} \sum_{j=1}^{J} \lambda_j r_j k^*_{\lambda Pr_j} \\ &\approx P_{\max} k_{\lambda Pr} \sum_{j=1}^{J} \lambda_j r_j \end{aligned} \tag{A3.39}$$

$$\begin{aligned} EIC &= \sum_{j=1}^{J} EENS_j \; c_{Wref}\left(r_j \right) b^*_j \\ &\approx P_{\max} k_{\lambda Prc} \sum_{j=1}^{J} \lambda_j c_{Pref}(r_j) \end{aligned} \tag{A3.40}$$

where J is the total number of components inflicting the delivery point.

<u>Short and long interruptions</u>

The general procedure provides reliability indices based on a resulting failure rate λ_j for each component, containing all types of failures. For some cases it may be of interest to discriminate between short ($\leq$ 3 min.) and long interruptions (> 3 min.). The definition is according to [12].

Large interruption costs are incurred by some customers due to long stops in the production process despite of short stops in the electricity supply. In cases of short interruptions it is irrelevant to check if the available capacity in the supply network matches the load for a given period. It is rather a problem of counting incidents and accumulate costs per incident.

This requires a reliability model which is able to discriminate between short and long interruptions. The reliability model RELRAD used in the general procedure should be extended to achieve this. This could be done by separating the failure rate in a rate for *temporary* and *permanent* failures [11]. Temporary failures lead to reconnection of the supply (automatically or manually), while permanent failures lead to reconnection (sectioning) time for some delivery points and repair time for others (in radial systems). Thus both temporary and permanent failures may lead to short and long interruptions.

Provided that the reliability model handles both, the costs for short and long interruptions may be calculated according to Eqs. (A3.37) and (A3.40) simulating temporary and permanent failures separately:

Temporary:

$$EIC_{ST} = P_{\max} c_{Pref_S} \sum_{j=1}^{J} \lambda_{Tj} k^*_{\lambda_T Pc_j}$$
$$EIC_{LT} = P_{\max} \sum_{j=1}^{J} \lambda_{Tj} c_{Pref}(r_j) k^*_{\lambda_T Prc_j} \quad \text{(A3.41)}$$

Permanent:

$$EIC_{SP} = P_{\max} c_{Pref_S} \sum_{j=1}^{J} \lambda_{Pj} k^*_{\lambda_P Pc_j}$$
$$EIC_{LP} = P_{\max} \sum_{j=1}^{J} \lambda_{Pj} c_{Pref}(r_j) k^*_{\lambda_P Prc_j} \quad \text{(A3.42)}$$

Total annual costs:

$$EIC_S = EIC_{ST} + EIC_{SP}$$
$$EIC_L = EIC_{LT} + EIC_{LP} \quad \text{(A3.43)}$$

where:

EIC_S = Annual costs for short interruptions (≤ 3 min.)
EIC_L = Annual costs for long interruptions (> 3 min.)

EIC_{ST} = Annual costs for short interruptions (≤ 3 min.) due to temporary failures
EIC_{SP} = Annual costs for short interruptions (≤ 3 min.) due to permanent failures
EIC_{LT} = Annual costs for long interruptions (> 3 min.) due to temporary failures
EIC_{LP} = Annual costs for long interruptions (> 3 min.) due to permanent failures
λ_{Tj} = average failure rate for temporary failures for component 'j'
λ_{Pj} = average failure rate for permanent failures for component 'j'
c_{PrefS} = cost for short (momentary) interruptions
$k^*_{\lambda TPcj}$ = correction factor for temporary failures on component 'j', Eq. (A3.27)
$k^*_{\lambda PPcj}$ = correction factor for permanent failures on component 'j', Eq. (A3.27).

The momentary (short) interruption cost estimates given by customer surveys are normalized with the (peak) demand, cfr. Ch. 2. Annual costs for short interruptions in Eqs. (A3.41) and (A3.42) are therefore determined on basis of the load. The specific cost for short interruptions is here assumed to be a constant and not a function of time in the interval 0 - 3 minutes.

Eqs. (A3.41 - A3.42) requires component specific correction factors for both temporary and permanent failures. This might be rather unrealistic according to data available. General correction factors can be applied instead like it was shown in the general procedure in Eqs. (A3.36 - A3.40).

A3.7 Calculation of correction factors

In this section the calculation of the correction factors is described. From Eq. (A3.31) we get the following expression of $k_{\lambda Prc}$:

$$k_{\lambda Prc} = \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h}\, q_{\lambda d}\, q_{\lambda m}\, k_{ph}\, k_{pd}\, k_{pm}\, k_{rh}\, k_{rd}\, k_{rm}\, k_{ch}\, k_{cd}\, k_{cm} \qquad \text{(A3.44)}$$

where the relative factors are given in Eqs. (A3.5) og (A3.28 - A3.30). The relative factors can be determined from load profiles, failure and interruption statistics and customer surveys on interruption costs.

Similar for the other factors:

$$k_{\lambda r} = \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h}\, q_{\lambda d}\, q_{\lambda m}\, k_{rh}\, k_{rd}\, k_{rm} \qquad \text{(A3.45)}$$

$$k_{\lambda P} = \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h}\, q_{\lambda d}\, q_{\lambda m}\, k_{ph}\, k_{pd}\, k_{pm} \qquad \text{(A3.46)}$$

$$k_{\lambda Pr} = \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h}\, q_{\lambda d}\, q_{\lambda m}\, k_{ph}\, k_{pd}\, k_{pm}\, k_{rh}\, k_{rd}\, k_{rm} \tag{A3.47}$$

$$k_{\lambda Pc} = \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h}\, q_{\lambda d}\, q_{\lambda m}\, k_{ph}\, k_{pd}\, k_{pm}\, k_{ch}\, k_{cd}\, k_{cm} \tag{A3.48}$$

The relative k-factors for load, repair time and specific cost are given by Eqs. (A3.28 - A3. 30).

We will look closer on how to derive the terms k_{ch}, k_{cd} and k_{cm}. From customer surveys we get estimates on the *absolute* interruption costs per interruption, e.g., in NOK per interruption. In addition we know the deviation from these estimates, which are given for a certain reference time, if the interruption occurs in another month, on another day or at another time during the day.

Consequently, we have information on the relative absolute cost, but not on the relative specific cost. In the Norwegian survey [34 - 36], the specific cost is given as the absolute cost per interruption divided by the energy not supplied for the reference interruption (for short interruption by the maximum load):

$$c_{Wref} = \frac{C_{Wref}}{EENS_{ref}} \tag{A3.49}$$

where C_{Wref} is the cost per interruption in NOK.

For an interruption at time t_j (h, d, m) with a given duration, this relation will be:

$$c_{Wj} = \frac{C_{Wj}}{EENS_j} \tag{A3.50}$$

From these two equations we can find the seeked term for the relative specific cost:

$$\frac{c_{Wj}}{c_{Wref}} = \frac{\dfrac{C_{Wj}}{EENS_j}}{\dfrac{C_{Wref}}{EENS_{ref}}} = \frac{C_{Wj}}{C_{Wref}}\,\frac{EENS_{ref}}{EENS_j} \tag{A3.51}$$

The relative EENS can be substituted by the relative load since the duration r_j is constant for a given interruption:

$$\frac{EENS_{ref}}{EENS_j} = \frac{P_{ref}}{P_j} \qquad \text{(A3.52)}$$

In the Norwegian survey the reference time is a Thursday in January at 10 a.m. which usually is the heavy load situation. Anyhow, the relative specific interruption cost at any time can be determined by:

$$\frac{c_{Wj}}{c_{Wref}} = \frac{C_{Wj}}{C_{Wref}} \frac{P_{ref}}{P_j} \qquad \text{(A3.53)}$$

See also Chapter 4.

The time variation in the specific cost in Eq. (A3.53) is separated in the three different variations on monthly, weekly and daily basis according to Eq. (A3.30) as shown in the following by inserting Eq. (A3.28) for the load at the time (h, d, m):

$$c_{W\,h,d,m} = \left(\frac{C_{Wh}}{C_{Wref}} \frac{P_{\max}}{P_h}\right)\left(\frac{C_{Wd}}{C_{Wref}} \frac{P_{av}}{P_d}\right)\left(\frac{C_{Wm}}{C_{Wref}} \frac{P_{av}}{P_m}\right) \frac{P_{ref}}{P_{\max}} c_{Wref} \qquad \text{(A3.54)}$$

Since results from customer surveys usually are presented as normalized values, the absolute cost C_W in month (m), on weekday (d), or in hour (h) are not given explicitly. However the surveys give information on the relative variation in cost per interruption (C_{Wh}/C_{Wref}, C_{Wd}/C_{Wref} and C_{Wm}/C_{Wref}).

Remark*:*

The correction factors presented in Eqs. (A3.25 - A3.27), (A3.44) and (A3.46 - A3.48) depend on the relation between the maximum and the average load (or the utilization time). In practical applications the general load profiles for different load types are used to determine these correction factors, which in next turn are used together with P_{max} for the delivery point in the assessment of reliability indices. If the utilization time deviates significantly from the one inherent in the relative profiles, the correction factors should be corrected with the factor T_{b2}/T_{b1}. T_{b2} is the actual utilization time in the delivery point, and T_{b1} is the utilization time used in the relative profile. An example is given for $k_{\lambda Prc}$ (Eq. A3.44):

$$k^{T_b}{}_{\lambda Prc} = \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{m=1}^{12} q_{\lambda h}\, q_{\lambda d}\, q_{\lambda m}\, k_{ph}\, k_{pd}\, k_{pm} \frac{T_{b2}}{T_{b1}} k_{rh}\, k_{rd}\, k_{rm}\, k_{ch}\, k_{cd}\, k_{cm} = k_{\lambda Prc} \frac{T_{b2}}{T_{b1}} \tag{A3.55}$$

Similarly should the load in Eq. (A3.28) be modified by the same factor.

Example of calculation of correction factors

As an example of the calculation of correction factors it is chosen to calculate $k_{\lambda Prc}$ in Equation (A3.44) for a *commercial* load. The relative factors are given in the tables below, and the month-, week- and day-factors are calculated separately according to Eqs. (A3.21 - A3.23). Finally the total annual correction factor in Eq. (A3.27) is calculated. The relative specific cost variations, determined from Eq. (A3.54) are shown below. It should be noted that the values in the tables are rounded off.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Sum
$q_{\lambda m}$	0.15	0.08	0.06	0.05	0.05	0.07	0.16	0.12	0.07	0.06	0.05	0.08	≈1.0
k_{pm}	*1.35*	1.41	1.19	0.83	0.72	0.82	0.82	0.82	0.72	0.91	1.05	1.35	
k_{rm}	1.49	1.46	0.92	0.78	0.73	0.78	0.72	0.73	0.78	0.85	0.87	1.19	
k_{cm}	0.74	0.72	0.88	1.29	1.47	1.31	1.25	1.29	1.44	1.20	1.08	0.91	
$\mathbf{k_{\lambda Prm}}$	0.23	0.12	0.06	0.04	0.04	0.06	0.12	0.09	0.05	0.05	0.05	0.12	**1.03**

Week	Mon	Tue	Wed	Thur	Fri	Sat	Sun	Sum
$q_{\lambda d}$	0.16	0.14	0.15	0.15	0.15	0.13	0.12	≈1.0
k_{pd}	1.09	1.04	1.06	*1.06*	1.05	0.90	0.79	
k_{rd}	0.89	0.88	1.14	0.90	0.97	1.21	1.02	
k_{cd}	0.85	0.93	0.92	0.94	1.15	0.96	0.68	
$\mathbf{k_{\lambda Prd}}$	0.14	0.12	0.16	0.13	0.17	0.14	0.07	**0.93**

Day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Sum
$q_{\lambda h}$	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.05	0.07	0.07	0.07	0.05	0.08	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.02	0.02	≈1.0
k_{ph}	0.35	0.36	0.36	0.36	0.36	0.36	0.38	0.42	0.49	*0.55*	0.56	0.56	0.55	0.54	0.52	0.51	0.50	0.47	0.45	0.39	0.37	0.36	0.36	0.36	
k_{rh}	1.73	1.37	1.51	1.21	0.99	0.81	0.87	0.71	0.63	0.82	0.84	0.75	0.68	0.81	0.96	1.38	1.25	1.10	1.17	1.14	1.07	1.41	1.58	1.95	
k_{ch}	1.38	1.37	1.37	1.38	1.38	1.35	1.63	1.50	1.60	1.44	1.41	1.42	1.66	1.68	1.73	1.78	1.42	1.50	1.56	1.79	1.38	1.40	1.41	1.42	
$k_{\lambda Prh}$	0.02	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.04	0.05	0.05	0.03	0.05	0.04	0.05	0.06	0.04	0.03	0.04	0.03	0.02	0.02	0.02	0.02	**0.69**

The term P_{ref}/P_{max} in Eq. (A3.54) is included in the hour-factor, such that $k_{ch} = (C_{Wh}/C_{Wref})\cdot(P_{ref}/P_{max})$. For this commercial load the utilization time is approx. 3750 hours, and $P_{ref} = 1.35\cdot1.06\cdot0.55P_{max} = 0.79P_{max}$. (The reference time is a Thursday in January at 10 a.m.).

Total correction factor:

$$k_{\lambda Prcm} = 1.03$$
$$k_{\lambda Prcd} = 0.93$$
$$k_{\lambda Prch} = 0.69$$
$$k_{\lambda Prc} = k_{\lambda Prcm} \bullet k_{\lambda Prcd} \bullet k_{\lambda Prch} = 0.66$$

If this factor were to be applied to a commercial load with utilization time 5000 hours, the factor should be modified according to Eq. (A3.55) such that $k^{Tb}_{\lambda Prc} = 0.88$.

The relative interruption cost for the commercial sector is given in the tables below.

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
C_{Wm}/C_{Wref}	1.00	1.01	1.05	1.07	1.06	1.08	1.03	1.06	1.04	1.09	1.13	1.23

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
C_{Wd}/C_{Wref}	0.93	0.97	0.97	1.00	1.20	0.87	0.54

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
C_{Wh}/C_{Wref}	0.62	0.62	0.62	0.62	0.62	0.62	0.79	0.79	1.00	1.00	1.00	1.00	1.15	1.15	1.15	1.15	0.89	0.89	0.89	0.89	0.64	0.64	0.64	0.64

As an example of the specific interruption cost at a specific time, the cost is calculated for a Wednesday in March at 4 p.m. (hour no. 16):

$$c_{W(16,wed,mar)} = 1.78 \bullet 0.92 \bullet 0.88 \bullet c_{Wref} = 1.44\, c_{Wref}$$

Appendix 4

Paper presented at PSCC ’96:

Delivery point interruption costs: Probabilistic modelling, time correlations and calculation methods

DELIVERY POINT INTERRUPTION COSTS: PROBABILISTIC MODELLING, TIME CORRELATIONS AND CALCULATION METHODS

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Keywords: Power system planning, Interruption costs, Uncertainty

ABSTRACT

Available data on failure rates, repair times and customer loads together with updated information from customer surveys about interruption costs allow us to improve calculation methods for assessment of expected unserved energy (EUE) and expected interruption costs (EIC). This paper proposes to take a closer look at possible correlations between the parameters and demonstrates by a simple example that neglecting such correlation may cause significant underestimation of EUE and EIC. By an additional Monte Carlo simulation it is found that the dispersion of repair time, assumed to be adequately modelled by exponential distribution, has a dominant influence on the dispersion of EUE and EIC.

1. INTRODUCTION

Reliability calculations and reliability cost/worth considerations have been around for many years. Ideas and concepts are generally accepted, but there are still obstacles caused by uncertainties and limitations due to imperfect data and models. Particular needs are better data and tools for assessment of reliability worth.

Recent customer surveys in e.g. Canada [1], United Kingdom [2] and in the Nordic Countries [3] provide up to date information on power interruption costs. Such data are used in conjunction with reliability analyses to predict the expected annual interruption costs for different customer categories.

Traditional analytical methods use average values of the parameters involved to calculate annual expected unserved energy (EUE) and annual expected interruption costs (EIC). It has been reported, however, that probability distributions of interruption duration and of specific interruption cost can be rather significant for the calculation of EIC, and that neglecting these aspects may lead to underestimation of annual interruption costs [e.g. 4, 5].

In this paper we are looking at the time correlation between failure rate, interruption duration, customer load and specific interruption cost, and we have found that neglecting this aspect may also underestimate the annual costs.

It is well known that the customer loads are characterized by typical daily, weekly and monthly cycles. From reports on failure rates and repair times it is found that these parameters have similar time profiles. Furthermore the latest customer survey in Norway showed that the same is true for the interruption costs.

It can be observed from these time profiles that peak values tend to occur at the same time, see fig. 1-3. If this correlation is significant, the simple traditional method might well underestimate EUE and EIC.

The analytical method taking into account the time correlation in the parameters, gives an estimate of **expected** values (EUE and EIC). There are additional stochastic variations, and a Monte Carlo simulation based on the same interruption model is added to illustrate the effect of stochastic parameter variations on the dispersion of the unserved energy and annual interruption costs.

The paper is organized as follows: Section 2 presents the main ideas and headlines of the modelling task. To make the paper more readable some modelling details are concentrated in appendix. An example that illustrates the analytical expectation method and the Monte Carlo approach for calculation of EUE and EIC is found in section 3. Section 4 discusses briefly the application aspect introducing a general delivery point as the interface between the supplier and the customer. Sections 5 and 6 contain a brief discussion and some conclusions.

2. MODELS AND CALCULATION METHODS

2.1 Parameter correlations

Examples of cyclic time variation in loads, failures and interruption costs are shown in figures 1-3.

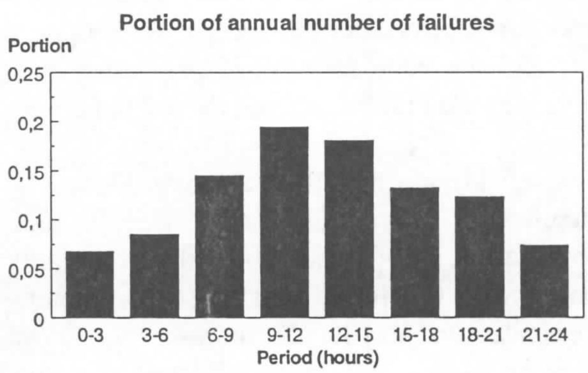

Fig. 1 Average daily variation in failures

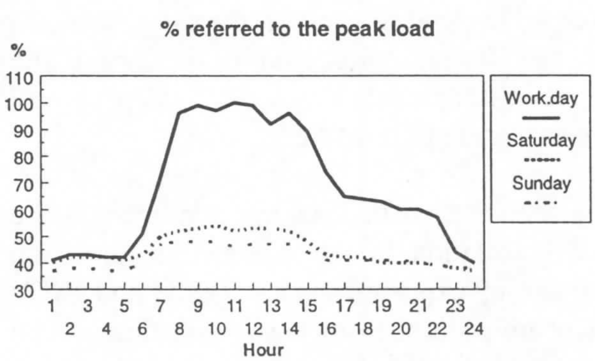

Fig. 2 Average daily variation in industrial load

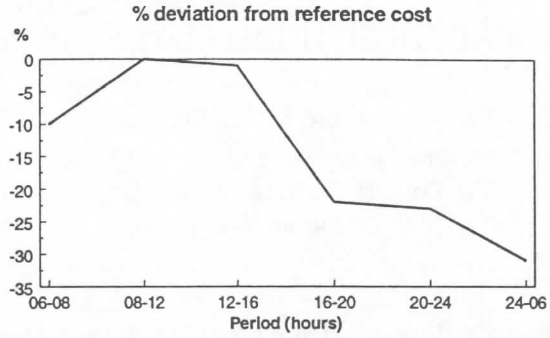

Fig. 3 Weighted daily variation in interruption costs, Industry

2.2 Expectation values and correlation

The annual expected interruption costs for a delivery point can be expressed by the following equation:

$$EIC=\frac{1}{n}\sum_{i=1}^{n}(\sum_{j=1}^{N_i}P_j r_j c_{Wj})_i \qquad (1)$$

where 'n' is the number of years calculated and N_i is the number of interruptions in year 'i'. P_j, r_j and c_{Wj} is the expected load, duration and specific cost for interruption no. 'j' in year no. 'i', respectively.

These expectation values are found from the daily, weekly and monthly time profiles described as variations relative to a set of reference values. Using the corresponding time profiles of failure rate the relative figures combine into a compound factor $k_{\lambda Prc}$ as shown in eq. (2). More details are found in appendix.

$$EIC=\lambda_{av}P_{\max}r_{av}c_{Wref}k_{\lambda Prc} \qquad (2)$$

Since the reference load P_{max} and the reference cost c_{Wref} are different from the annual average figures, the formula can be rewritten in terms of average load and average cost:

$$EIC=\lambda_{av}P_{av}r_{av}c_{av}(\frac{P_{\max}}{P_{av}})(\frac{c_{Wref}}{c_{av}})k_{\lambda Prc} \qquad (3)$$

The time correlation between the four parameters is now represented by the factor

$$(\frac{P_{\max}}{P_{av}})(\frac{c_{Wref}}{c_{av}})k_{\lambda Prc} \qquad (4)$$

If this factor appears to be significantly different from 1.0, the traditional calculation method (which is represented by the expression in front of this factor in eq. (3)), will give inaccurate results for EIC. Numerical results found in section 3 of this paper indicate that at least for certain customer categories the correlation is significant and can hardly be neglected.

A similar expression to eq. (2) for the unserved energy (EUE) will be:

$$EUE=\lambda_{av}P_{\max}r_{av}k_{\lambda Pr} \qquad (5)$$

In eq. (5) the factor $k_{\lambda Pr}$ includes the time correlation in three parameters and corrects for using the annual peak load as reference.

2.3 Expectation values and Monte Carlo simulation

The analytical model including the factors $k_{\lambda Prc}$ and $k_{\lambda Pr}$ that accounts for correlation, allows us to assess the expected unserved energy and expected costs, EUE and EIC. The time profiles that determine these factors represent an average cyclic behaviour of failure rate, repair time, load and cost. It might be useful also to assess the stochastic variation, giving additional information to the expectation values. This problem can be approached by a Monte Carlo simulation and the results can be compared to the expectation method.

The Monte Carlo approach includes the following steps:

1) Determine the number of failures (interruptions) supposed to occur next year. Poisson distribution is assumed.
2) For each failure (interruption) determine in which *month*, *weekday* and *hour* it occurs. The relative variations in failure rate (see appendix) that was used to implement correlation in the analytical model are now used as probabilities to pin-point the time when the event takes place.
3) Determine the expected load μ_P at the time of interruption using eq. (D) from appendix. The actual load is found from a normal distribution with μ_P and the standard deviation σ_P as parameters.
4) The expected duration of the interruption is now determined using eq. (C) from appendix. To find the actual duration *r*, a relevant probability distribution has to be specified, for example the exponential-, Gamma- or Weibull function.
5) Determine expected specific interruption cost using the actual Customer Damage Function (CDF) with *r* from step 4) and eq. (E) from appendix. A probability distribution for the cost has to be specified to find the actual cost c_W.

Summarizing briefly: The same basic information that was used to represent correlation for the analytical expectation method is now used to time tag an interruption and find the time dependent (moving) average values of load, interruption duration and interruption cost. The Monte Carlo simulation gives approximately the same expectation values as the analytical method and provides additional stochastic components from probability distributions "vertical" to the moving average values.

3. AN EXAMPLE

The analytical method and the Monte Carlo simulation procedure presented in section 2 will be demonstrated for the delivery point in fig. 4: An industrial customer. The data and reference values are given in the figure.

The objective is to estimate the expected annual interruption costs in the long run for the delivery point, supplied by an overhead line with an average failure rate of 1 failure per year.

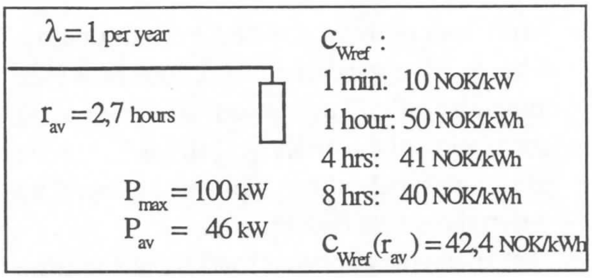

Fig. 4 Example: Industrial load.

3.1 Expectation values

a) Neglecting correlation

$$EUE=\lambda_{av}P_{av}r_{av}=122\ kWh/year$$
$$EIC=\lambda_{av}P_{av}r_{av}c_{av}=7270\ NOK/year \qquad (6)$$

The Interrupted Energy Assessment Rate (IEAR) is calculated to 59,6 NOK/kWh.

b) With correlation, $k_{\lambda Pr}= 0.60$ and $k_{\lambda Prc}= 0.76$ for Industry:

$$EUE=\lambda_{av}P_{max}r_{av}k_{\lambda Pr}=162\ kWh/year$$
$$EIC=\lambda_{av}P_{max}r_{av}c_{Wref}k_{\lambda Prc}=8700\ NOK/year \qquad (7)$$

Neglecting correlation underestimates EUE by approximately 30 % and EIC by 20 %. The calculated IEAR is 53,7 NOK/kWh.

3.2 Monte Carlo simulation

Number of simulations: 200 (=200 years)
Interruption duration: Exp. distr.: r_{av}= 2,7 hours.
Load: Normal distr.: σ_P = 10 %.
Specific cost: Normal distr.: σ_c = 20 %

Results:

Number of interruptions:
207/200 = 1,035 per year
EUE = 167 kWh/year
EIC = 9215 NOK/year
IEAR = 55,2 NOK/kWh

Dispersions from average values are depicted in fig. 5-7.

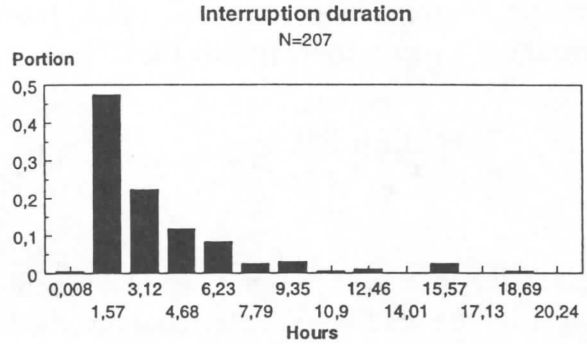

Fig. 5 Interruption time, 200 simulations.

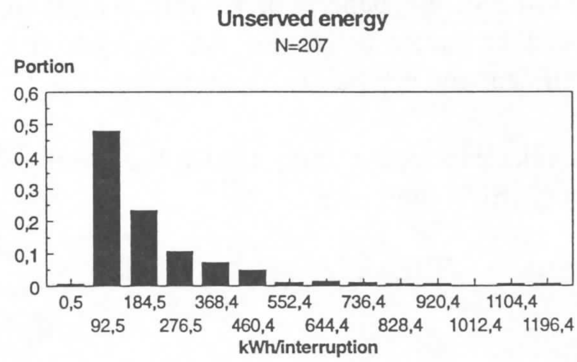

Fig. 6 Unserved energy, 200 simulations.

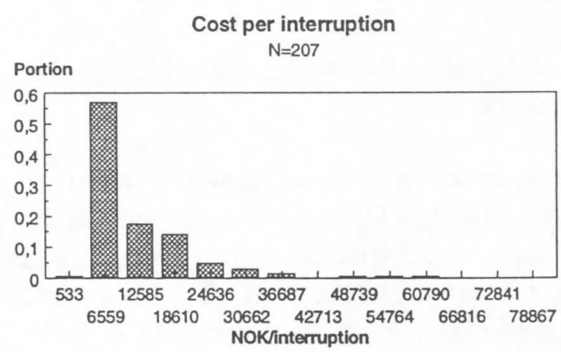

Fig. 7 Cost per interruption, 200 simulations.

4. APPLICATION: DELIVERY POINT

In the example in section 3 we have used a radial system to calculate EUE and EIC. In radial systems there is a simple connection between component failures and load interruptions, and between interruption duration and repair time or sectioning time. Given a reliability model that can predict number and duration of interruptions as a function of component failures and repairs for

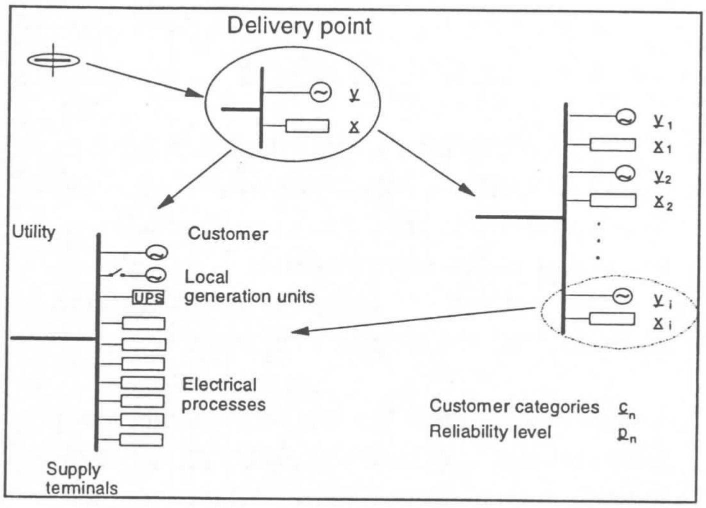

Fig. 8 A general delivery point.

a general network, the method we have described is applicable. We assume that such a model is available. Thus a general delivery point is defined, see figure 8.

A *general delivery point* can be any busbar in the LV, MV or HV distribution system or a load point in the transmission system. It can represent either a single customer, a group of customers or an interface point to a lower network level (or another network owner), supplying several delivery points or customers. A bulk supply point is a delivery point at the most aggregated level.

A general delivery point is the interface between the utility (supplier) and a customer. The term 'customer' here represents an end consumer, another utility (network owner) or a lower system level within the utility's own network.

The general delivery point consists of the supply terminals (the busbar), the electrical processes (the load) and the local generation units (reserve supply). Each delivery point is characterized by a specific reliability level and by different customer categories connected.

The cost models in eq. (1)-(3) represent the expected annual costs for a general delivery point, based on *estimates of interruptions and durations* for the load point.

There are two main types of decision problems, namely the local and global decision problems. A *local* decision problem is a short term planning problem, where a typical objective is to compare a local investment with expected gains obtained by a reduction in interruption costs EIC. In a *global* decision problem the objective is to perform a long term power system planning where the reliability cost/worth is one of several considerations.

The Norwegian Energy Act, put into operation in 1991, addresses both items. According to the Act, planning, operation and maintenance of the power system shall be optimized from a socio-economic point of view, taking into account investment costs, costs of losses, maintenance costs and interruption costs. The method described in this paper aims to be part of the tools needed to meet this requirement.

5. DISCUSSION

The numerical analysis verifies the qualitative impression of correlation given by the curves, fig. 1-3. For the particular example we find that the correlation increases the expected annual interruption cost EIC by approx. 20% compared to the case where correlation is neglected. We do not claim that the result is characteristic in general, but on the other hand we have used data based on available statistics and customer surveys, and we believe the result justifies the extra effort made by representation of the time profiles and calculation of the correction factors.

Parameters used to calculate the expected unserved energy and expected annual interruption costs may have a significant deviation from the expected value. The result of this is exactly what the Monte Carlo simulation approach illustrates in fig. 5-7. The striking observation is that the probability distribution of interruption time r seems to be the dominant factor for the empirical probability density function of unserved energy and cost per interruption, fig. 6-7.

We have assumed that the interruption duration is exponentially distributed with an average value of 2,7 hours. This assumption is based on empirical data, which shows the characteristic positively skewed form that can be represented by the exponential distribution. Other known distribution functions that we have tried to fit the data do not differ significantly from the exponential distribution for the long durations, which are assumed to be most interesting.

The stochastic variations in load and specific cost, represented by a standard deviation of 10% and 20% respectively, do not appear to have the same dominant influence as the exponential distribution for interruption duration. However, the normality assumption for the specific cost is a quite rough approximation of the available data.

With a limited number of 200 simulations, the empirical average values do not differ significantly from the expectation values found by the analytical method using correlation factors.

Generally it is assumed that the Monte Carlo simulation adds valuable information to the expectation values. Qualitatively as well as quantitatively we can see that the probability of getting values of unserved energy and interruption costs significantly larger than the expectation values is far from negligible. In practical life it means that for a single year the observed unserved energy and interruption costs may be much larger than the annual average in the long run.

The numerical results given in this paper are somewhat preliminary. The work is part of an ongoing PhD research that will be published and presented towards the end of 1996. The numerical tool we have used to handle the rather comprehensive database and produce the results is also preliminary and is currently being improved to handle more simulations etc. This will allow us to do a lot more testing on different data and other probability distributions as well as different decision problems.

6. CONCLUSIONS

The paper has briefly presented a model to calculate expected unserved energy and expected interruption costs. The particular capability of the model is the representation of correlation between parameters: failure rate, interruption duration, load and specific interruption cost.

Using data from real life it is demonstrated that the correlation may have significant influence on the estimation of the annual unserved energy and interruption costs, and that underestimation may take place if the correlation is neglected.

Monte Carlo simulation adds valuable information to the expectation values produced by the analytical method and demonstrates that large deviations from expectation values are likely to occur.

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APPENDIX: MODELLING DETAILS

A year is divided into time units according to the typical cyclic load variations:
24 hours · 7 days · 12 months = 2016 time units

Expectation values in a particular month (m), weekday (d) and hour (h) are:

A1. Failure rate

The number of failures at a specific time is given by the proportion of the annual number of failures occurring in the particular month, weekday or hour:

$$k_{\lambda m}=\frac{\lambda_m(k)}{\lambda_{av}}=\frac{\lambda_m(k)}{\sum\lambda_m(k)},\ \sum_{k=1}^{12}k_{\lambda m}=1.0$$
$$k_{\lambda d}=\frac{\lambda_d(j)}{\lambda_{av}}=\frac{\lambda_d(j)}{\sum\lambda_d(j)},\ \sum_{j=1}^{7}k_{\lambda d}=1.0 \qquad \text{(A)}$$
$$k_{\lambda h}=\frac{\lambda_h(i)}{\lambda_{av}}=\frac{\lambda_h(i)}{\sum\lambda_h(i)},\ \sum_{i=1}^{24}k_{\lambda h}=1.0$$

$$\lambda_{h,d,m}(i,j,k)=\frac{\lambda_h(i)}{\lambda_{av}}\frac{\lambda_d(j)}{\lambda_{av}}\frac{\lambda_m(k)}{\lambda_{av}}\lambda_{av} \qquad \text{(B)}$$

where λ_{av} is the annual average number of failures.

A2. Interruption time

$$r_{h,d,m}(i,j,k)=\frac{r_{av,h}(i)}{r_{av}}\frac{r_{av,d}(j)}{r_{av}}\frac{r_{av,m}(k)}{r_{av}}r_{av} \qquad \text{(C)}$$

Reference value: annual average r_{av}.

A3. Load

$$P_{h,d,m}(i,j,k)=\frac{P_{av,h}(i)}{P_{max}}\frac{P_{av,d}(j)}{P_{av}}\frac{P_{av,m}(k)}{P_{av}}P_{max} \qquad \text{(D)}$$

Reference value: annual peak load P_{max}.

A4. Specific interruption cost

$$c_{W(h,d,m)}(i,j,k)=\frac{c_{Wav,h}(i)}{c_{Wref}}\frac{c_{Wav,d}(j)}{c_{Wref}}\frac{c_{Wav,m}(k)}{c_{Wref}}c_{Wref} \qquad \text{(E)}$$

Reference value: specific cost at the reference time used in the customer survey, c_{Wref}.

A5. Expected unserved energy and cost

$$EUE=\sum_{k=1}^{12}\sum_{d=1}^{7}\sum_{h=1}^{24}\lambda_{h,d,m}P_{h,d,m}r_{h,d,m} \qquad \text{(F)}$$

$$EUE=\lambda_{av}P_{max}r_{av}k_{\lambda Pr} \qquad \text{(G)}$$

$$EIC=\sum_{k=1}^{12}\sum_{d=1}^{7}\sum_{h=1}^{24}\lambda_{h,d,m}P_{h,d,m}r_{h,d,m}c_{W(h,d,m)} \qquad \text{(H)}$$

$$EIC=\lambda_{av}P_{max}r_{av}c_{Wref}k_{\lambda Prc} \qquad \text{(I)}$$

Appendix 5

Cost description: Customer costs and utility costs

This appendix gives a description of costs incurred by customers and utilities upon occurrence of interruptions and costs due to specific actions taken upon interruptions. These cost elements are explained in the following. The description provides a basis for determination of annual interruption costs and other variable costs, which are inputs to the optimization problem. The description refers to the delivery point description in Ch. 3.

A5.1 Customer information

For the determination of reliability worth it is convenient to look more closely at the delivery point (or the customer), in order to identify the cost elements which are important in the relationship between the utility and the customer and for the decision problem.

The electrical processes (loads) and local generation units for an end consumer are described in the following. The purpose of this detailed description is to provide a framework for the identification of customer interruption costs and a basis for the aggregation of costs for several customers and delivery points.

The description is based on an industrial or commercial customer. The customer has various processes utilizing electricity, for example heating, lighting, computers and the production process itself. The customer might have local generation of electricity or other energy resources as a supplement to the electricity supplied by the utility, in addition to reserve units or UPS (Uninterruptible Power Supply). The processes and local generation units connected to the supply terminals are shown in Fig. A5.1.

Fig. A5.1 gives a stylized description of possible local generation facilities and electrical processes that might be at the customer site, and it does not show the relation between the different processes.

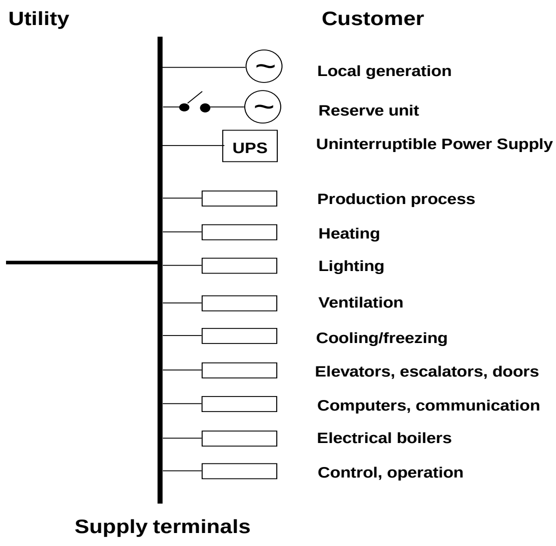

Fig. A5.1 Examples of a customer’s electrical processes and local generation units.

Information on local generation and alternative energy resources as well as reserve supply possibilities is necessary for the evaluation of energy not supplied to the customer and for the further evaluation of the customer's total costs.

The various processes and the local generation can be described by vectors $\underline{x}$ and $\underline{y}$ respectively:

$\underline{x} = [x_1, x_2, \ldots.., x_m]$ $\underline{y} = [y_1, y_2, \ldots.., y_n]$

where:

x_1 = Production process
x_2 = Heating
x_3 = Lighting
.
.
m = number of processes.

where:

y_1 = Local generation unit
y_2 = Reserve unit
y_3 = UPS
.
.
n = number of power supply facilities.

A simpler and more general version of Fig. A5.1 using the vectors is shown in Fig. A5.2 (cfr. Fig. 3.2):

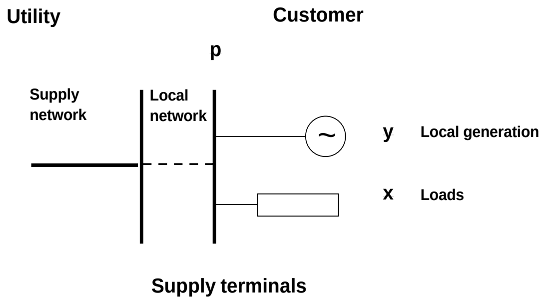

Fig. A5.2 General description of delivery point.

The general delivery point in Fig. A5.2 consists of a y-vector decribing the local generation LG and an x-vector describing the total load P, and it is characterized by the reliability level $\underline{p}$. The figure marks that the customer might have a local supply network.

A5.2 Customer costs

Interruptions may give quite different consequences for the customer's different electrical processes and as such result in different costs or economic losses. Some of the loads are more critical than others in an economic sense. The Customer cost per Interruption depends on the duration of the interruption and the types of loads as well as the local generation and reserve supply possibilities:

$$CIC(\underline{x}, \underline{y}, r)$$

where r is the interruption time, $\underline{x}$ is a vector for electrical loads and $\underline{y}$ is a vector for local generation and reserve supply possibilities (see Ch. 3).

CIC($\underline{x}$, $\underline{y}$, r) comprises economic losses due to damage of equipment or goods, loss of production, overtime payment, start-up of production process and other extra costs. These costs will vary with *time of occurrence*, i.e., time of the day, day of the week and month of the year.

In case of interruptions the customer might take on certain actions such as operation of reserve supply or repair of failed reserve equipment. The cost associated with these actions is called the Customer Action Cost:

$$CAC(\underline{y}, r)$$

CAC($\underline{y}$, r) contains the extra costs of running/operating the reserve upon the occurrence of interruption, or the repair costs upon failure of the reserve equipment, and is assumed to depend only on local generation/reserve supply possibilities and duration of the interruption. This cost element is usually very small compared to the customer interruption cost and the utility action cost (see next section).

CIC($\underline{x}$, $\underline{y}$, r) and CAC($\underline{y}$, r) include the costs per incident that in general should be taken into account by the utility in the optimization of the reliability level.

Customer investment costs, I_C, influencing the reliability level $\underline{p}$ as well as the total interruption costs, are costs of local generation units or costs of reserve supply equipment. The maintenance costs affecting the reliability level, are assumed to be included in CAC($\underline{y}$, r).

A summary of the customer's cost elements related to the reliability of supply, yields the following total annual costs. The total *annual* costs of interruptions (CIC) and actions (CAC) are determined by the reliability level $\underline{p}$ and the time of occurrence. CIC and CAC are the customer's variable costs.

CUSTOMER ANNUAL RELIABILITY COSTS

CIC($\underline{x}$, $\underline{y}$, $\underline{p}$)	= Total customer interruption costs
CAC($\underline{y}$, $\underline{p}$)	= Total customer action costs
I_C	= Investments influencing $\underline{p}$

At an aggregated level it will be a comprehensive task to include each individual customer's investment costs in the optimization. I_C will in such cases refer to investments at a lower system level concerning a particular delivery point (cfr. the definition of customer in Ch. 3).

A5.3 Utility costs

When the electricity supply provided by the utility is interrupted, the incurred costs by the utility are the economic losses of no sales. The cost of energy not supplied

$$UIC(\underline{x}, \underline{y}, r)$$

represents the Utility Interruption Cost, corresponding to the customer interruption cost. $UIC(\underline{x}, \underline{y}, r)$ is usually very small compared to $CIC(\underline{x}, \underline{y}, r)$, typically a few percent. The utility interruption cost depends on the customer's demand for electricity supply, the customer's local generation facilities and the duration of the interruption.

An objective for the utility is to minimize the inconvenience due to interruptions for the consumers and to minimize both utility and customer costs. Upon a disturbance in the transmission or distribution system, the utility will take on certain actions depending on whether the disturbance leads to consumer interruptions, whether there is a failure to be repaired and so on. Similarly when there is a planned outage due to some maintenance work for instance, certain actions will take place.

Such utility actions yield a cost per incident:

$$UAC(\underline{z}, r)$$

The choice of actions will depend on the type of incident, the type of consumers involved, the number of skilled employees available, the type of spare parts and other materials available and so on.

The various utility actions can be described by a vector $\underline{z}$:

$$\underline{z} = [z_1, z_2, \ldots\ldots, z_q]$$

where q is the number of different utility actions available and the different z's can be any specific measure from the groups listed below:

EXAMPLES OF UTILITY ACTIONS
☞ Restoration of supply (sectioning, reconnection)
- manually
- by automation - by use of reserve supply ☞ Repair of failed component - type of component/material (- repair) ☞ Planned disconnections - type of maintenance - use of reserve supply ☞ Live line working - type of maintenance

The utility action costs depend on the different specific measures available as well as the duration. These costs will vary with *time of occurrence*, i.e. time of day, day of week and month of year.

Utility investment costs, I_U, influencing the reliability level and the total interruption costs are costs of building new lines and transformer stations, changing to more reliable equipment, installation of automation and so on. The maintenance cost affecting the reliability level is assumed to be included in UAC($\underline{z}$, r).

A summary of the utility's cost elements related to the reliability of supply, yields the following total annual costs. The total *annual* costs of utility interruptions (UIC) and utility actions (UAC) are determined by the reliability level $\underline{p}$ and the time of occurrence. UIC and UAC are the utility's variable costs.

UTILITY ANNUAL RELIABILITY COSTS	
UIC($\underline{x}$, $\underline{y}$, $\underline{p}$)	= Total utility interruption costs
UAC($\underline{z}$, $\underline{p}$)	= Total utility action costs
I_U	= Utility investments influencing $\underline{p}$

A5.4 Annual variable costs

The annual costs due to interruptions and reliability measures are the sum of the interruption and action costs per incident during a year. In cases involving more than one customer it will be necessary to aggregate the costs for the customers connected to a particular delivery point. The aggregated cost will then be influenced by the type of customer (customer category) in addition to the reliability level. Dealing with more than one delivery point, a further aggregation of costs is necessary, taking into account the number of delivery points and their specific reliability level.

A general description of the annual variable costs can then be as follows. The description should be valid for a single customer, a mixture of customers and a mixture of delivery points.

Annual variable costs concerning a general delivery point:

$$UIC(\underline{x},\underline{y},\underline{c},\underline{p}) = \sum_{i,n} UIC_{i,n}(\underline{x},\underline{y},r)$$

$$UAC(\underline{z},\underline{p}) = \sum_{h} UAC_{h}(\underline{z},r)$$

$$CIC(\underline{x},\underline{y},\underline{c},\underline{p}) = \sum_{i,n} CIC_{i,n}(\underline{x},\underline{y},r)$$

$$CAC(\underline{y},\underline{c},\underline{p}) = \sum_{i,n} CAC_{i,n}(\underline{y},r)$$

where:

i = annual number of interruptions to the delivery point
h = annual number of failures/disturbances, planned disconnections etc. in the system supplying the particular delivery point.
r = duration of the incident
$\underline{c}$ = vector of customer categories connected to the delivery point
n = number of customers or delivery points connected to the delivery point.

The equation gives principally the total annual variable costs for a general delivery point, as a basis for Value Based Reliability Planning. It should be noted that if one deals with a delivery point supplying several delivery points, the total costs for each delivery point will be determined by the individual reliability level.

A comparison of the customer and utility costs will show that UIC is typically a few percent of CIC, and that CAC is neglectable compared to UAC, which means that the first and last elements of the annual costs above can be neglected for practical considerations.

Appendix 6

Data and results for Chapter 7

This appendix gives data for the examples in Chapter 7 and correlation factors based on failures in overhead lines and cables (cfr. Section 7.2).

A6.1 Time variation data for base case

This section gives the time variation data for the base case in Sections 7.1 - 7.3. The data are given as relative values according to Eqs. (5.4), (5.7), (5.8), (5.10) and (A3.54). All values are rounded off in the tables.

Monthly variation

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$q_{\lambda m}$	0.15	0.08	0.06	0.05	0.05	0.07	0.16	0.12	0.07	0.06	0.05	0.08
k_{rm}	1.49	1.46	0.92	0.78	0.73	0.78	0.72	0.73	0.78	0.85	0.87	1.19
k_{pm}, industr.	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
k_{pm}, comm.	*1.35*	1.41	1.19	0.83	0.72	0.82	0.82	0.82	0.72	0.91	1.05	1.35
k_{cm}, industr.	1.0	1.01	1.0	1.0	1.02	1.05	0.94	1.01	1.03	1.04	1.06	1.08
k_{cm}, comm.	0.74	0.72	0.88	1.29	1.47	1.31	1.25	1.29	1.44	1.20	1.08	0.91

Weekly variation

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
$q_{\lambda d}$	0.16	0.14	0.15	0.15	0.15	0.13	0.12
k_{rd}	0.89	0.88	1.14	0.90	0.97	1.21	1.02
k_{pd}, industr.	1.17	1.17	1.17	1.17	1.17	0.58	0.58
k_{pd}, comm.	1.09	1.04	1.06	*1.06*	1.05	0.90	0.79
k_{cd}, industr.	0.86	0.86	0.86	0.86	0.86	1.02	1.04
k_{cd}, comm	0.85	0.93	0.92	0.94	1.15	0.96	0.68

Daily variation

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$q_{\lambda h}$	0.02	0.02	0.02	0.02	0.02	0.03	0.04	0.05	0.07	0.07	0.07	0.05	0.08	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.02	0.02
k_{rh}	1.73	1.37	1.51	1.21	0.99	0.81	0.87	0.71	0.63	0.82	0.84	0.75	0.68	0.81	0.96	1.38	1.25	1.10	1.17	1.14	1.07	1.41	1.58	1.95
k_{ph}, ind.	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
k_{ph}, com.	0.35	0.36	0.36	0.36	0.36	0.36	0.38	0.42	0.49	*0.55*	0.56	0.56	0.55	0.54	0.52	0.51	0.50	0.47	0.45	0.39	0.37	0.36	0.36	0.36
k_{ch}, ind.	1.24	1.24	1.24	1.24	1.24	1.24	1.62	1.62	1.17	1.17	1.17	1.17	1.16	1.16	1.16	1.16	1.41	1.41	1.41	1.41	1.39	1.39	1.39	1.39
k_{ch}, com.	1.38	1.37	1.37	1.38	1.38	1.35	1.63	1.50	1.60	1.44	1.41	1.42	1.66	1.68	1.73	1.78	1.42	1.50	1.56	1.79	1.38	1.40	1.41	1.42

A6.2 Time variation data for overhead lines and cables

Relative time variation data for failures on overhead lines and cables (distribution system) are given in this section. The data are used in Sections 7.5 and 7.6. All values are rounded off.

Monthly variation

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$q_{\lambda m}$, lines	0.23	0.10	0.07	0.05	0.04	0.06	0.11	0.09	0.06	0.06	0.05	0.09
$q_{\lambda m}$, cables	0.09	0.08	0.07	0.08	0.09	0.09	0.10	0.10	0.07	0.08	0.08	0.08
k_{rm}, lines	1.37	1.43	0.84	0.64	0.64	0.67	0.58	0.47	0.74	0.84	0.88	1.17
k_{rm}, cables	2.15	1.08	0.80	0.62	0.48	1.0	1.19	1.16	0.75	0.90	0.61	1.35

Weekly variation

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
$q_{\lambda d}$, lines	0.14	0.13	0.16	0.15	0.15	0.14	0.13
$q_{\lambda d}$, cables	0.14	0.15	0.16	0.17	0.15	0.12	0.10
k_{rd}, lines	0.99	0.78	1.35	0.97	0.90	0.93	0.91
k_{rd}, cables	1.03	0.80	0.67	0.74	0.87	1.71	1.49

Daily variation

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$q_{\lambda h}$, lines	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.05	0.05	0.07	0.07	0.06	0.07	0.06	0.06	0.05	0.04	0.04	0.04	0.04	0.04	0.03	0.02	0.03
$q_{\lambda h}$, cabl.	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.04	0.06	0.07	0.07	0.05	0.07	0.06	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03
k_{rh}, lines	1.69	1.46	1.43	1.07	0.98	0.72	1.31	0.79	0.90	1.01	0.87	0.69	0.67	0.81	0.89	1.66	0.97	1.06	0.99	0.94	1.08	0.95	1.21	1.13
k_{rh}, cabl.	2.60	0.93	2.36	1.0	1.0	1.05	0.52	0.85	0.63	0.50	0.60	0.98	0.71	0.79	1.23	1.19	0.71	0.97	0.60	0.90	0.73	1.82	1.0	3.08

A6.3 Correlation factors

Correlation factors for the industrial and commercial load from Chapter 4, based on failures on overhead lines and cables are given in Tables A6.1-A6.4. Cfr. Table 7.6 and Figs. 7.3 and 7.4.

Table A6.1 Correlation factors for **industrial** load, based on failures in **overhead** lines.

Variables	Monthly	Weekly	Daily
Failures vs cost	- 0.32	0.64	0.91
Failures vs load		0.65	0.83
Failures vs duration	0.57	0.73	- 0.50
Duration vs cost	0.22	0.21	- 0.36
Duration vs load		0.21	- 0.30
Load vs cost		1.0	0.90

Table A6.2 Correlation factors for **commercial** load, based on failures in **overhead** lines.

Variables	Monthly	Weekly	Daily
Failures vs cost	- 0.34	0.67	0.89
Failures vs load	0.55	0.68	0.93
Failures vs duration	0.57	0.73	- 0.50
Duration vs cost	0.0	0.06	- 0.34
Duration vs load	0.91	0.25	- 0.42
Load vs cost	0.13	0.82	0.93

Table A6.3 Correlation factors for **industrial** load, based on failures in **cables**.

Variables	Monthly	Weekly	Daily
Failures vs cost	- 0.35	0.88	0.86
Failures vs load		0.89	0.85
Failures vs duration	0.33	- 0.90	- 0.51
Duration vs cost	- 0.16	- 0.95	- 0.42
Duration vs load		- 0.95	- 0.31
Load vs cost		1.0	0.90

Table A6.4 Correlation factors for **commercial** load, based on failures in **cables**.

Variables	Monthly	Weekly	Daily
Failures vs cost	- 0.14	0.81	0.83
Failures vs load	- 0.27	0.88	0.88
Failures vs duration	0.33	- 0.90	- 0.51
Duration vs cost	- 0.16	- 0.64	- 0.44
Duration vs load	0.56	- 0.83	- 0.47
Load vs cost	0.13	0.82	0.93

A3.4 Time variation data for example with parallel lines

This section gives relative time variation for the example with two parallel lines in Section 7.7. The data are given for each outage event. Values are rounded off.

Load

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
P_m/P_{av}	1.30	1.27	1.21	0.94	0.74	0.70	0.68	0.72	0.84	1.04	1.26	1.32

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
P_d/P_{av}	1.05	1.06	1.05	1.03	1.02	0.91	0.89

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
P_h/P_{max}	0.49	0.48	0.47	0.47	0.48	0.49	0.54	0.62	0.66	0.66	0.66	0.65	0.64	0.63	0.62	0.61	0.61	0.61	0.61	0.61	0.60	0.58	0.56	0.52

Failures and repair time

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$q_{\lambda m}$, lines A, B	0.15	0.04	0.02	0.02	0.05	0.10	0.12	0.10	0.08	0.05	0.12	0.15
$q_{\lambda m}$, A&B	0.17	0.03	0.003	0.004	0.04	0.10	0.13	0.10	0.08	0.04	0.13	0.17
k_{rm}, lines A, B	0.57	1.85	3.87	3.77	1.67	0.88	0.71	0.65	1.03	1.67	0.69	0.57
k_{rm}, A&B	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Appendix 7

Data and results for Chapter 8

This appendix gives data and results for the cases in Chapter 8. All values are rounded off in the tables.

A7.1 Relative cost variation

As an example of aggregate relative cost variation, the cost variation for the Norwegian energy consumption is calculated according to Eq. (8.5). The results are given in the tables below. Cfr. Fig. 8.2.

Monthly variation

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
specific cost	0.87	0.86	0.94	1.15	1.25	1.17	1.11	1.15	1.24	1.11	1.06	0.98
absol. cost	1.0	1.01	1.03	1.04	1.04	1.05	1.0	1.03	1.03	1.06	1.08	1.14

Weekly variation

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
specific cost	0.89	0.93	0.92	0.93	1.04	0.99	0.85
absol. cost	0.97	0.99	0.99	1.0	1.10	0.82	0.65

Daily variation

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
sp. cost	1.26	1.26	1.25	1.26	1.26	1.25	1.49	1.43	1.35	1.27	1.26	1.26	1.38	1.39	1.42	1.44	1.33	1.37	1.40	1.51	1.30	1.31	1.31	1.32
abs. cost	0.72	0.72	0.72	0.72	0.72	0.72	0.87	0.87	1.0	1.0	1.0	1.0	1.07	1.07	1.07	1.07	0.88	0.88	0.88	0.88	0.75	0.75	0.75	0.75

A7.2 Data for transmission system case

This section gives the relative time variation data for the transmission system case in Section 8.3.

Load

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
P_m/P_{av}	1.30	1.27	1.21	0.94	0.74	0.70	0.68	0.72	0.84	1.04	1.26	1.32

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
P_d/P_{av}	1.05	1.06	1.05	1.03	1.02	0.91	0.89

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
P_h/P_{max}	0.49	0.48	0.47	0.47	0.48	0.49	0.54	0.62	0.66	0.66	0.66	0.65	0.64	0.63	0.62	0.61	0.61	0.61	0.61	0.61	0.60	0.58	0.56	0.52

Failures and repair time, local statistics

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$q_{\lambda m}$	0.18	0.02	0.0	0.04	0.04	0.10	0.12	0.12	0.14	0.05	0.10	0.10
k_{rm}	0.98	5.97	0.0	1.62	1.79	0.31	0.46	0.27	2.94	0.06	0.19	0.19

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
$q_{\lambda d}$	0.14	0.14	0.14	0.14	0.14	0.14	0.14
k_{rd}	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$q_{\lambda h}$	0.05	0.03	0.07	0.07	0.0	0.06	0.05	0.0	0.06	0.01	0.09	0.05	0.04	0.03	0.08	0.07	0.02	0.06	0.04	0.02	0.03	0.06	0.03	0.03
k_{rh}	0.41	0.02	3.54	0.28	0.0	0.25	0.74	0.0	1.23	0.0	0.94	0.42	3.14	0.09	0.23	0.79	0.0	2.50	0.11	0.0	0.15	2.34	0.77	0.22

Failures and repair time, total statistics lines ≥ 300 kV

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
$q_{\lambda m}$	0.25	0.11	0.06	0.02	0.04	0.07	0.12	0.09	0.05	0.05	0.06	0.09
k_{rm}	1.19	0.60	2.69	0.05	4.01	0.60	0.53	0.25	0.43	1.87	0.39	0.61

Day	Mon	Tue	Wed	Thur	Fri	Sat	Sun
$q_{\lambda d}$	0.13	0.16	0.15	0.17	0.13	0.12	0.14
k_{rd}	1.03	1.46	0.87	1.08	1.07	1.15	0.28

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
$q_{\lambda h}$	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.06	0.06	0.06	0.05	0.05	0.05	0.06	0.07	0.05	0.04	0.06	0.03	0.03	0.03	0.03	0.03
k_{rh}	0.94	0.48	3.26	2.47	0.93	0.46	0.33	2.79	0.37	1.51	1.33	0.43	0.54	1.44	0.66	0.31	0.28	0.52	0.62	1.51	2.77	0.63	0.29	0.27

A7.3 Results for the distribution system case

Table A7.1 Reliability indices for delivery points in the cable network. Existing system.

Delivery point	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
N1	2.19	1.10	0.50	158.5	88.6	187.4
N2	2.19	1.11	0.51	426.1	240.4	508.6
N3	2.19	1.27	0.58	308.0	198.4	418.6
N4	2.19	1.27	0.58	85.2	54.9	115.8
N5	2.19	1.27	0.58	334.9	215.8	455.2
N6	2.19	1.27	0.58	571.1	367.9	776.3
N7	2.19	1.27	0.58	424.2	247.1	15021.4
N8	2.19	1.27	0.58	21.1	12.3	747.3
N9	2.19	1.27	0.58	114.0	66.4	4035.6
N10	2.19	1.27	0.58	262.8	153.1	10328.7
N11	2.19	1.27	0.58	296.5	172.7	10500.1
N12	2.19	1.27	0.58	100.3	58.4	3549.8
N13	2.19	1.27	0.58	205.3	127.0	3183.2
N14	2.19	1.27	0.58	295.3	157.1	11339.4
N15	2.19	1.27	0.58	271.6	144.5	10430.7
N16	2.19	1.27	0.58	394.7	229.9	13975.2
N17	2.19	1.27	0.58	284.0	183.0	386.1
SUM/ average	2.19	1.25	0.57	4553.4	2717.6	85959.4

Table A7.2 Reliability indices for delivery points in the overhead network. Existing system.

Delivery point	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
N18	2.19	2.17	0.99	68.8	75.9	189.8
N19	2.19	2.17	0.99	53.8	53.4	148.6
N20	2.19	2.17	0.99	71.8	79.2	198.1
N21	2.19	2.23	1.02	6.0	6.8	17.3
N22	2.19	2.23	1.02	62.8	71.1	175.2
N23	2.19	2.23	1.02	3.0	3.4	8.7
N24	2.19	2.23	1.02	70.3	79.8	204.0
N25	2.19	2.28	1.04	115.1	133.6	347.2
N26	2.19	2.28	1.04	95.7	111.0	288.6
N27	2.19	2.28	1.04	124.1	144.0	374.3
N28	2.19	2.28	1.04	26.9	31.2	81.2
SUM/ average	2.19	2.23	1.02	698.1	795.3	2032.9

Table A7.3 Reliability indices for delivery points in the cable network.
Circuit breaker at point N2.

Delivery point	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
N1	0.44	0.22	0.50	31.6	17.7	37.5
N2	0.44	0.23	0.52	85.0	49.9	105.4
N3	0.44	0.39	0.88	61.5	60.7	127.1
N4	0.44	0.39	0.88	17.0	16.8	35.2
N5	0.44	0.39	0.88	66.8	66.0	138.3
N6	0.44	0.39	0.88	113.9	112.5	235.8
N7	0.44	0.39	0.88	84.6	75.6	4128.7
N8	0.44	0.39	0.88	4.2	3.8	205.4
N9	0.44	0.39	0.88	22.7	20.3	1109.2
N10	0.44	0.39	0.88	52.4	46.8	2835.3
N11	0.44	0.39	0.88	59.2	52.8	2886.0
N12	0.44	0.39	0.88	20.0	17.9	975.7
N13	0.44	0.39	0.88	41.0	38.8	880.2
N14	0.44	0.39	0.88	58.9	48.0	3110.1
N15	0.44	0.39	0.88	54.2	44.2	2860.8
N16	0.44	0.39	0.88	78.8	70.3	3841.1
N17	0.44	0.39	0.88	56.7	56.0	117.3
SUM/ average	0.44	0.37	0.83	908.5	797.8	23628.8

Table A7.4 Reliability indices for delivery points in the overhead network. **Circuit breaker** at point N2.

Delivery point	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
N18	2.19	2.17	0.99	68.8	75.9	189.8
N19	2.19	2.17	0.99	53.8	53.4	148.6
N20	2.19	2.17	0.99	71.8	79.2	198.1
N21	2.19	2.23	1.02	6.0	6.8	17.3
N22	2.19	2.23	1.02	62.8	71.1	175.2
N23	2.19	2.23	1.02	3.0	3.4	8.7
N24	2.19	2.23	1.02	70.3	79.8	204.0
N25	2.19	2.28	1.04	115.1	133.6	347.2
N26	2.19	2.28	1.04	95.7	111.0	288.6
N27	2.19	2.28	1.04	124.1	144.0	374.3
N28	2.19	2.28	1.04	26.9	31.2	81.2
SUM/ average	2.19	2.23	1.02	698.1	795.3	2032.9

Table A7.5 Reliability indices for delivery points in the cable network.
New cable - two radials.

Delivery point	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
N1	0.44	0.22	0.50	31.6	17.7	37.5
N2	0.44	0.23	0.52	85.0	49.9	105.4
N3	0.44	0.39	0.88	61.5	60.7	127.1
N4	0.44	0.39	0.88	17.0	16.8	35.2
N5	0.44	0.39	0.88	66.8	66.0	138.3
N6	0.44	0.39	0.88	113.9	112.5	235.8
N7	0.44	0.39	0.88	84.6	75.6	4128.7
N8	0.44	0.39	0.88	4.2	3.8	205.4
N9	0.44	0.39	0.88	22.7	20.3	1109.2
N10	0.44	0.39	0.88	52.4	46.8	2835.3
N11	0.44	0.39	0.88	59.2	52.8	2886.0
N12	0.44	0.39	0.88	20.0	17.9	975.7
N13	0.44	0.39	0.88	41.0	38.8	880.2
N14	0.44	0.39	0.88	58.9	48.0	3110.1
N15	0.44	0.39	0.88	54.2	44.2	2860.8
N16	0.44	0.39	0.88	78.8	70.3	3841.1
N17	0.44	0.39	0.88	56.7	56.0	117.3
SUM/ average	0.44	0.37	0.83	908.5	797.8	23628.8

Table A7.6 Reliability indices for delivery points in the overhead network.
New cable - two radials.

Delivery point	λ (no./year)	U (hours/year)	r (hrs/interr.)	EPNS (kW/year)	EENS (kWh/year)	EIC (NOK/year)
N18	1.77	1.98	1.11	56.0	69.1	176.2
N19	1.77	1.98	1.11	43.8	54.1	137.9
N20	1.77	1.98	1.11	58.4	72.1	183.9
N21	1.77	2.03	1.15	4.9	6.2	16.1
N22	1.77	2.03	1.15	51.1	64.9	169.1
N23	1.77	2.04	1.15	2.4	3.1	8.1
N24	1.77	2.04	1.15	57.2	72.8	190.0
N25	1.77	2.09	1.18	93.7	122.2	324.4
N26	1.77	2.09	1.18	77.9	101.6	269.7
N27	1.77	2.09	1.18	101.0	131.8	349.7
N28	1.77	2.09	1.18	21.9	28.6	75.8
SUM/ average	1.77	2.04	1.15	568.4	726.5	1901.0

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