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HENRY LÅGLAND

Comparison of Different Reliability Improving Investment Strategies of Finnish Medium-Voltage Distribution Systems

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ERRATA:

p. XXIII, line 25 SAIFI System Average Interruption Duration Index, should read System Average Interruption Frequency Index

p. XXIII, line 25 SAIDI System Average Interruption Frequency Index, should read System Average Interruption Duration Index

p. 34, line 21 $T-SAIDI=\sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij}\times t_{ij}/mp$, should read: $T-SAIDI=\sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij}\cdot t_{ij}/mp$

p. 49, line 27 $T-SAIDI=1/3\cdot f_l L\cdot t_s+1/3\cdot k_d f_d L\cdot t_s+2/3\cdot f_l L\cdot t_c+2/3\cdot f_l L\cdot t_c+$ should read:

$T-SAIDI=1/3\cdot f_l L\cdot t_s+1/3\cdot k_d f_d L\cdot t_s+2/3\cdot f_l L\cdot t_c+2/3\cdot k_d f_d L\cdot t_c+$

p. 53, line 23 $\frac{(n-1)}{2n}(f_l+k_d f_d)\cdot(a+b\cdot t_c)\cdot L\cdot P$,should read: $\frac{(n-1)}{2n}(f_l+k_d f_d)\cdot(a+b\cdot t_c)\cdot L\cdot P+$

p. 63, line 15 ohc_1kV, should read: coc_1kV

p.67, line 25 $U_h=\sqrt{3}\left(I_p R+I_q X\right)$, should read: $U_h\approx\sqrt{3}\left(I_p R+I_q X\right)$

p. 85, line 13 in Chapter 2.4.2 is…, should read: in Chapter 2.4.3 is…

p. 94, line 21 The latter ratio…, should read: The first ratio…

p. 99, line 2-3 Should be deleted.

p. 130, line 2 ..on pages 103-105, should read:…on pages 102-104

p. 142, line 16 …real feeder F2, should read …real feeder F1

p. 165, line 19 $4k_d\cdot L/2\cdot f_l\cdot L/2+4k_d\cdot L/2\cdot k_d f_d\cdot L/2)$ should read: $4k_d\cdot L/2\cdot f_l\cdot L/2+4k_d\cdot L/2\cdot k_d f_d\cdot L/2$

p. 171 is changed to a new page, see page Acta Wasaensia 171 (enclosed)

p. 172, line 11 $4k_d L/4\cdot f_l L/4\cdot t_c+4k_d L/4\cdot f_l L/4\cdot t_c+$ should read: $8k_d L/4\cdot f_l L/4\cdot t_c+8k_d L/4\cdot f_l L/4\cdot t_c+$

p. 173, line 15 $k_d L/6\cdot k_d f_d L/6\cdot t_s$,should read: $k_d L/6\cdot k_d f_d L/6\cdot\left(t_s+t_r/m\right)$

p. 173, line 16 $k_d L/6\cdot f_l L/6\cdot\left(t_s+t_r/m\right)$,should read: $k_d L/6\cdot f_l L/6\cdot t_s$

Appendix 3. Calculation of *T–SAIDI* in a homogenous OHL feeder protected by a substation recloser and equipped with two remote controlled line switches when $m = k_d L/2n$. The number of outages is z. The number of different outage durations related to a certain outage is x. The number of distribution substation areas in the areas where the outage duration was t_{ij} is mpk_{ij}.

Section: Load	Section: Fault	$\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$
z1T	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s$
	z2Tl	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z2Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z2Ll	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
z1L	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s + k_d L/4 \cdot f_l L/4 \cdot t_r / m$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Tl	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z2Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z2Ll	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
z2T	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z2Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s$

(continues)

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Julkaisun nimike

Suomalaisten keskijännitejakelujärjestelmien toimitusvarmuutta parantavien investointistrategioiden vertailu

Tiivistelmä

Sähkönjakelutoimiala Suomessa on voimakkaasti säännösteltyä ja verkkoon sijoitetun pääoman tuotto on alhaista. Alhainen tuotto vähentää ulkopuolisten sijoittajien kiinnostusta toimialaan. Kohtuullisen tuoton valvonnan toisella jaksolla 2008–2011 malliin on tullut mukaan kannuste, joka sallii korkeampaa tuottoa verkonhaltijalle oikein kohdennetuista verkostoinvestoinneista ja niiden vaikutuksesta alentuneista toiminnan kustannuksista ja jakelun häiriöttömyydestä. Tämän työn tavoitteena on löytää keskijännitejakelujärjestelmien kustannustehokkaita investointistrategioita suomalaisille jakeluyhtiöille toisen valvontajakson kannustinten ohjaamana.

Tässä työssä vyöhykekonseptia on kehitetty edelleen johtamalla lausekkeet homogeenisen jakelujärjestelmän taloudellisille ja jakeluvarmuuden tunnusluvuille vyöhykelukumäärän funktiona. Keskijännitejakelujärjestelmien kustannustehokkaimmat investointistrategiat haetaan tarkastelemalla verkostoautomaation ja erilaisten verkkorakenteiden teknisistä ja taloudellisista vuorovaikutuksista. Kymmentä johtoautomaatioratkaisua on sovellettu kuuteen taajama/haja-asutusverkkomalliin sekä suomalaisen jakeluyhtiön verkon kahteen lähtöön. Analyyttinen lähestyminen sisältää verkkojen ja niiden toimintojen mallintamisen sekä taloudellisten ja jakeluvarmuuden tunnuslukujen laskennan. Seuraavat investointikohteet on käsitelty: erilaiset sähkönjakelujärjestelmät, uusi sähköasema, uusi kytkemö, keskitetty maasulkuvirran kompensointi, kaapelointi sekä johtoautomaatio.

Työn tulosten arvo on siinä, että ne paljastavat lähtöautomaation vaikutuksen erilaisiin sähkönjakelun rakenteiden luotettavuuteen ja talouteen. Aikaansaatu läpinäkyvyys mahdollistaa kansallisen ja/tai jakeluyhtiökohtaisen investointistrategian luomisen investointien hyödyn optimoimiseksi.

Asiasanat

sähkönjakelu, sähköverkot, keskeytyskustannus, jakeluvarmuus, verkostoautomaatio

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Abstract

The electricity distribution sector in Finland is highly regulated and the return on investments in distribution networks is low. Low profits don't make the electricity distribution sector attractive to outside investors. During the second regulatory period of 2008–2011 incentives are included into the Finnish regulation model which allows higher profits for the network owners for right allocated network investments leading to lower operation and interruption costs. The goal of the thesis is to find cost-effective medium-voltage distribution system investment strategies for the Finnish power distribution companies with respect to the incentives of the second regulatory period.

In this work the sectionalisation concept is further developed by deriving equations for a homogeneous electricity distribution system for the economical and reliability indices as a function of the number of sectionalisation zones. The cost-effective medium-voltage distribution system investment strategies are found by studying the technical and economic interaction of feeder automation on different network structures. Ten feeder automation schemes have been applied to six urban/rural area generic feeders and two real rural area feeders of a distribution company in western Finland. The analytical approach includes modelling of the feeders and feeder functions and calculation of the economical and reliability indices. The following investment areas are included: different electricity distribution systems, new substation, new switching station, central earth-fault current compensation, cabling and feeder automation.

The value of the results of this work is that they reveal the influence that feeder automation has on the reliability and economy of different distribution structures. This created transparency enables a national and/or distribution company network investment strategy to optimise the economic benefits of investments.

Keywords

electricity distribution, distribution networks, outage cost, distribution reliability, distribution automation

FOREWORD

First and foremost I would like to thank the University of Vaasa, the Graduate School in Electrical Energy Engineering and the Finnish electrical industry for giving me the opportunity and necessary assistance to carry out this doctoral project. I also owe my deepest gratitude to my supervisor Professor Kimmo Kauhaniemi for his continued support, expert guidance and encouragement in carrying out this research and his valuable advice and contribution during the preparation of this thesis.

I thank the pre-examiners Professor Pertti Järventausta of the Department of Electrical Energy Engineering at Tampere University of Technology and Professor Jarmo Partanen of the Department of Electrical Engineering at Lappeenranta University of Technology for their guidance, feedback and comments and their willingness to be the pre-examiners of my thesis.

I also thank ABB Finland in Vaasa for their cooperation. Special thanks to development manager Tapio Hakola of ABB Substations for his support. I wish to express my appreciation to Vaasan Sähköverkko Oy for giving me the possibility to study their distribution systems. Special thanks to the Managing Director Juha Rintamäki who enabled this.

Vaasa, March 2012

Henry Lågland

Contents

Tables

Figures

Abbreviations

AC	Alternating current
AMR	Automatic meter reading
AR	Auto-reclosing
auto	Automatic operation of the remote controlled distribution substation and fault location performed by substation circuit-breaker/recloser protection relay
CA	Customer Automation
CEFCC	Central earth-fault current compensation
CEIDS	Consortium for Electric Infrastructure to Support a Digital Society
CIRED	International Conference on Electricity Distribution
CIS	Customer information system
COC	Coated overhead conductor
DA	Distribution automation
DAR	Delayed auto-reclosing
DC	Direct current
DG	Distributed generation
DIP	Voltage dip
Dispower	Distributed Generation with High Penetration of Renewable Energy Sources
DMS	Distribution Management System
DPLC	Distribution power line carrier
DSS	Distribution substation
EDF	Electricité de France
EEA	Engineering Economic Analysis
EHV	Extra high voltage
Elforsk	Swedish R&D organisation
EMA	Energy Market Authority in Finland
ENEL	Italian energy provider
EPRI	Electric Power Research Institute (USA)
EU	European Union
FA	Feeder automation
FDIR	Fault detection, isolation and service restoration
FI	Fault indication
FEI	Finnish Energy Industries
fi	Locally read and set fault indicators
GIS	Graphical information system
GPRS	General Packet Radio Service
GSM	Global System for Mobile Communications
HSAR	High-speed auto-reclosing
HV	High voltage
IEC	International Electrotechnical Comission
IED	Intelligent electronic device
IEEE	the Institute of Electrical and Electronics Engineers
IT	Information technology

LAS	Link arrangement system
LEFCC	Local earth-fault current compensation
LIR	Linking recloser
LR	Lateral line recloser
LV	Low voltage
MAIFI	Momentary Average Interruption Frequency Index
man	No automation
MV	Medium voltage
N/O	Normally open
NDE	Non-delivered energy
NIS	Network information system
NOP	Normally open point
O/C	Over-current
OHL	Overhead line
OR	Open ring
QoS	Quality of supply
p	Pole
PDSS	Primary distribution substation
R	Remote controlled line recloser
rc	Remote control
rfi	Remote read and set fault indicator
RMU	Ring Main Unit
ROI	Return on investment
RTU	Remote terminal unit
SA	Substation automation
SAT	Satellite
SCADA	Supervisory Control And Data Acquisition
SEF	Svenska Elverksföreningen
SESKO	The Electrotechnical Standardization Association in Finland
SF6	Sulphur hexafluoride
SS	Substation
TR	Remote controlled trunk line recloser
UGC	Underground cable
Unipede	The association of the European Electricity Industry and of worldwide affiliates and associates
VTT	Technical Research Centre of Finland
VY	University of Vaasa
z	Zone
ZHDSS	Zone handling distribution substation

Symbols

a	Annuity
A	Availability
B	Benefit
B/C	Benefit/ cost
CAIDI	Customer Average Interruption Duration Index

c	Unit cost
C	Cost
ELL	Emergency loading level
f	Fault frequency
F	Load factor
frAR	Fraction of successful auto-reclosings
I	Current
incB/C	Incremental benefit/cost
k	Density
L	Length of line
LL	Loading level
LLF	The loss load factor
MAIFI	Momentary Average Interruption Frequency Index
mp	Total number of the distribution transformer areas in the distribution area
mph	Total sum of the outage durations of the distribution substation areas
mpk	Number of the distribution transformer areas
n	Number of zones
N	Number of primary distribution transformers connected to a feeder
P	Active power
p	Interest rate
r	Average outage time
SAIFI	System Average Interruption Duration Index
SAIDI	System Average Interruption Frequency Index
T	Time period
t	Time
U	Unavailability
W	Energy
X	Reactance

Greek letters

ε	Annuity factor
λ	Expected failure rate
µ	Expected repair time

Subscripts

%	Percentage
0	No load
1	Primary
2	Secondary
AR	Auto reclosing
cj	Capacitive
com	Earth-fault current compensation
cu	Copper

d	Distribution substation
DAR	Delayed auto-reclosing
DIP	Voltage dip
h	Loss
HSAR	High-speed auto-reclosing
i	Number
INT	Total outage
INV	Investment
j	Number
l	Losses
lo	Load
max	Maximum
NDE	Non-delivered energy
OPE	Operation
P	Power
p	Primary
PB	Payback
rc	Remote control
r	Repair
s	Switching
t	Transformer
tot	Total
W	Energy

1 INTRODUCTION

1.1 Background and motivation

The electricity markets in the Nordic countries were opened in the 1990's with the Finnish electricity market opening in 1995. As the distribution sector in Finland is still regulated, the low level of regulated returns does not make the electricity distribution sector attractive for the investors. The reliability indices of the electricity distribution system have not improved in recent years since there have not been strong incentives for power quality improvements.

The main part of the Finnish electricity distribution system was first constructed during the latter part of the 19th century. Since the technical age of the oldest part of the distribution system is about half a century, the distribution companies now face the start of reinvestment. To help Europe to reduce its emissions of carbon dioxide Finland has to increase the share of renewable energy to 38 per cent by 2020. Feed-in tariffs were introduced in 2010 to increase wind power and biogas energy production. The second regulatory period of 2008–2011 has introduced both penalties and incentives for power quality improvements (Figure 1). In economic regulation quality in power supply can be divided into reliability, voltage quality and quality of customer service. According to Finnish regulation, the cost of non-delivered energy (NDE) and short interruptions are considered as continuity of supply problems, while voltage dips (DIP) are categorised as voltage quality issues (Honkapuro 2008: 76–77). The effects of the quality of supply (QoS) in the new regulation model are quite different from the first regulation period. There are three incentives for the quality of supply. As standard compensation costs are categorised as controllable operational costs, they directly affect both the profit of the company and the input parameter of the efficiency benchmarking.

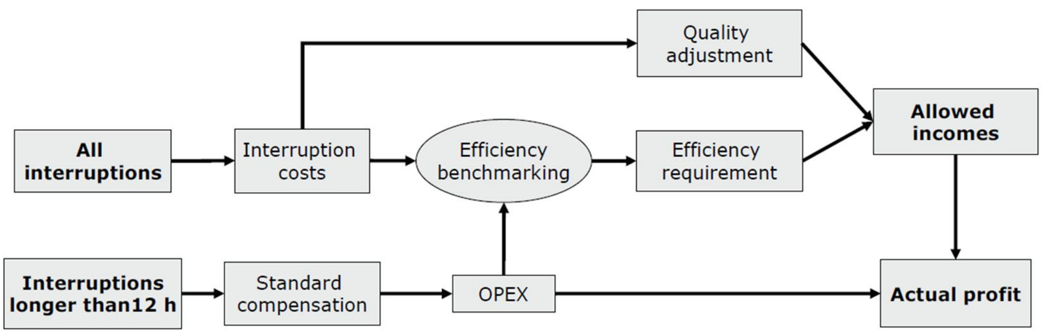


Figure 1. Effects of interruptions on the allowed incomes and profit of a distribution company (Honkapuro 2008: 164).

The other two incentive mechanisms, namely, quality adjustment and inclusion of interruption costs in efficiency benchmarking are two-way mechanisms while the standard compensation scheme provides only penalties. The standard compensation scheme and quality adjustment have an instant effect on the profits of the company, while efficiency benchmarking affects the efficiency requirement during the next regulatory period (Honkapuro 2008: 164–165). This should result in cost-effective investments in power quality.

Due to above mentioned circumstances and recent technology developments, the challenges of the distribution companies are demanding. The transport and energy sectors have a central role in handling the global climate change encouraging the use of renewables and distributed generation (DG) in electricity production. Thus distributed generation has to be integrated into the distribution system to utilise the positive effects of it and minimising the negative effects of embedded generation. Global warming may also impact power quality by causing more storms and floods. According to the customers one of the most important tasks for the distribution companies is however to improve the quality of the electricity distribution in today's digital society. This work gives cost-effective investment strategy solutions how to improve the power quality and profitability of electricity distribution in the Finnish medium voltage (MV) distribution systems.

1.2 The research problem

Since the existing Finnish medium voltage distribution systems are also to be replaced, there is an opportunity to introduce new electricity distribution concepts which are more cost-effective and/or have higher electricity distribution reliability than the systems that are to be replaced. This is possible since new components and systems have been developed. Remote controlled line reclosers, numeric multifunctional programmable protection relays, low-cost primary distribution substations based on distribution substation technology, the 1000 V distribution system, automatic meter reading (AMR) and the development of new information systems enable the use of more complex distribution systems than the ordinary rural distribution system.

Until recent years the Finnish rural/sub-urban distribution systems have been built as radial overhead line feeders with short lengths of underground cables. When the distribution systems are re-constructed, new network protection and feeder automation (FA) schemes will be used to achieve a distribution system with a feasible total cost. Different investment strategies are used to achieve this goal. Investment strategies studied in this work can be divided into primary distribution substation and feeder level investments (Figure 2). The main research target regarding new distribution systems is to identify, find and present reliable medium voltage distribution systems with a low annual total cost. The target with regard to existing distribution systems is to find and present investment alternatives which when implemented on the existing distribution systems would give lower annual total outage cost. The research problem is thus to define the present Finnish rural/sub-urban electricity distribution system reliability level and present optional reliability improvement strategies with respect to reliability, availability, cost-efficiency and economy. By studying the interaction of the different MV distribution functions and regulation on the effectiveness of different investment strategies the risk of wrong investments can be minimized. This study aims to give solutions to the distribution companies in carrying out their investment strategies regarding the technology and economy of different investment strategies. It also finds the most cost-effective actions and programs to improve quality of supply in the area of electricity distribution reliability. The influence of actions in one investment strategy at a time on the reliability indices and costs are studied while the distribution system is used as a parameter and the automation scheme as a variable. Thus the benefits of actions in the different strategies can be compared and the efficiency of different investment strategies examined.

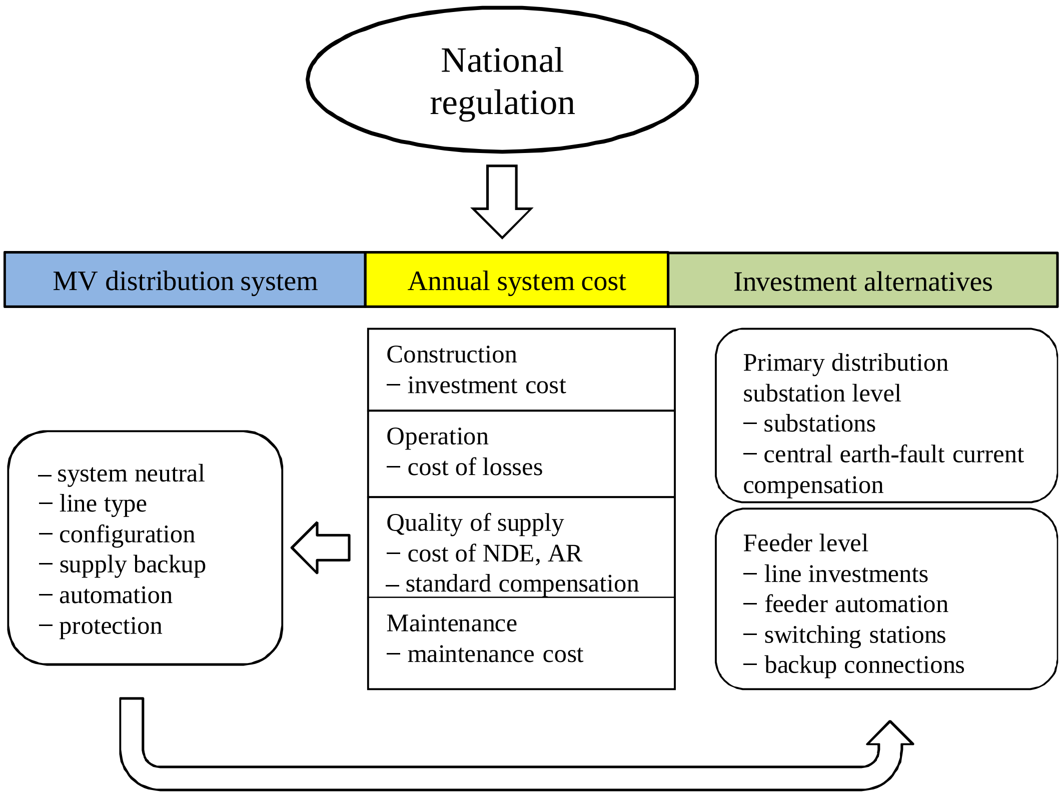


Figure 2. The frame of the work (left) and studied investment strategies (right).

1.3 The research method

Available network configurations have been investigated in an earlier work by using an international questionnaire on medium voltage network structures, applied techniques and methods in different countries. The results of the survey were utilised in a thesis regarding network layouts for simulation purposes (Lågland 2004). Different distribution network types and automation schemes used in different countries were also studied as a part of the visionary network research project in Finland which was brought to conclusion in 2006 (Kumpulainen et al. 2007). As a part of the research project, a separate comprehensive report on different distribution systems used in different countries was completed in 2006 (Lågland & Kauhaniemi 2006). The earlier work is now continued in this thesis by studying the effects of the interaction of feeder type, feeder automation and investment strategy on the economy and distribution reliability of different distribution systems.

The neutral isolated rural/sub-urban radial overhead line feeder is used as the basic distribution system to which other distribution systems are compared. The distribution reliability of the other identified cost-effective feeder models is based on utilising the pros of a property in a location of the distribution system where it is most efficient. This leads to model feeders which have different line types and protection schemes. Thus utilising Finnish distribution system statistics, generic feeders are modelled to study the behaviour of the model feeders with regard to economy and reliability. This is done by using Excel spread sheet calculation (Figure 3), followed by modelling different identified feeder automation schemes. Included are both remote control related and line reclosing based feeder automation schemes. To model the switching time process in different fault situations, a switching model which is based on the degree of feeder automation of the distribution system is created. The supply restoration system models a two-stage supply restoration process. By choosing different input parameters, desired values of the economy and distribution reliability of the different model feeders and the benefits of different investment strategies can be compared. To verify and compare the calculated results with the indices of real medium voltage distribution systems, the indices of two feeders in a network company in Western Finland are calculated in the same way. Although the feeders are already equipped with some feeder automation, the cost-efficiency of various feeder automation schemes is studied and the impact of the supply reliability is studied and the results are compared to the created model distribution systems.

INPUT	MODEL	CALCULATION	OUTPUT
Components	Circuit configurations	Electrical behaviour	Electrical constraints
Electrical data			Electricity distribution reliability indices
	Automation schemes	Electricity distribution reliability	Costs
Outage data			Savings = benefits
Automation scheme	Switching model	Economy	Benefit/cost
Cost data			Incremental benefit/cost
	Restoration model	Sensitivity studies	Payback times
Variation ladders			Sensitivity

Figure 3. The modelling and calculating method used in this study.

1.4 The scope of the research

The average annual interruption duration of Finnish transmission distribution systems at 110 kV level has been 1–2 minutes per connection point. As the average interruption duration of medium voltage distribution systems on the distribution transformer level has been 100–180 minutes a natural effective target for reliability improvement investments is the MV distribution system. Finnish medium voltage electricity distribution systems are divided into rural, urban and city distribution systems (FEI 2010: 1). Because city and urban distribution systems are excluded from this work, complex and high-cost distribution systems such as those with several lines feeding each load are excluded from this study. Studied distribution systems are suburban and rural distribution systems. *Suburban* distribution systems typically originate from a primary distribution substation in a suburban area and end in the surrounding rural area. The feeder automation area studied in this work includes automated fault detection, isolation and service restoration (FDIR). Transformer and feeder load transforming and balancing as well as phase load balancing are not in the scope of this research. In the total cost of electricity distribution the distribution system construction cost, the cost of losses and the cost of quality of supply are included. In the total cost of distribution systems containing underground cable lines the cost of earth-fault compensation are not included while the cost of earth-fault current compensation of overhead lines are included. Because the distribution systems studied here are so close to each other from an operational point of view only the costs that differ and that can be influenced with the studied investment methods are included. Consequently the operation and maintenance costs are excluded from the study. The outage costs considered here are the cost of non-delivered energy and the cost of auto-reclosing (AR), both calculated on the distribution substation level. The cost of voltage dips is excluded because the number of dips can't be reduced by the use of feeder automation.

1.5 Outline of the work

Chapter 2 builds a theoretical framework of the work. It starts with a literature review of the following main issues related to the work: the influence of the Finnish electricity market regulation model on the quality and price of electricity supply, cost efficiency of electricity distribution investments, distribution system consequences due to underground cabling of electricity distribution lines, substation automation (SA), feeder protection optimization and feeder automation. Next there is an overview of distribution system properties influencing the quality of electricity supply, such as system neutral grounding and wire system, level and rate of underground cabling as well as network type. This section is concluded with an overview of the most common electricity distribution reliability indices used in Finland to measure distribution reliability. Chapter 2 continues with a short presentation of feeder automation methods used to improve electricity distribution reliability. Both remote control related methods, such as fault indication (FI) and remote control of line switches, and line reclosing methods are presented. In Section 2.4 expressions for the calculation of the annual total outage cost and the reliability indices of homogenous radial overhead line distribution feeders are derived.

For the evaluation of the efficiency of different reliability improving investment strategies a generic electricity distribution system is designed in Chapter 3. The design starts with dimensioning of the primary substation distribution area by using Finnish medium voltage electricity distribution statistics average data and ends with detailed feeder design. After checking of the electrical constraints of the generic model feeders, different remote control related and line reclosing feeder automation schemes are designed to be applied to the generic model feeders for the purpose of revealing the influence of feeder automation on the performance of the different feeder models and cost-efficiency of different investment strategies. As all the different feeder models and feeder automation schemes are combined, also new feeder and feeder automation combinations, which do not exist in Finnish distribution companies, are included and investigated. The chapter ends with a presentation of the calculated reliability indices of the different generic feeder models.

In Chapter 4, the calculation and results of the economical indices of the different generic model feeders with the different feeder automation schemes as variable are presented. Calculated and presented cost levels are the annual investment cost, the annual cost of losses, the annual total outage cost and the annual total cost. The cost information system formulated in this chapter forms a good basis for the calculation of the annual cost saving and cost efficiency of different reliability improving investment methods as presented in Chapter 5, where the annual economical saving, benefit/cost, incremental benefit/cost and the payback time of different investment strategies are presented.

The same reliability and economical indices are used in Chapter 6, where a practical case study is performed where two real feeders of a distribution company in Western Finland are evaluated with regard to a wider use of feeder automation. In Chapters 7 and 8 the results and conclusions of the work are presented and evaluated.

1.6 Scientific contribution

This doctoral thesis shows that it is possible to present the impact of the main parameters of a distribution system on the economy and reliability of the distribution system on a common level. This is done by identifying the main parameters that influence the behaviour of the distribution system and modelling the distribution system for the purpose of calculating the economic and reliability indices to compare different investment strategies.

The impact of regulation is shown by revealing the relationship between the outage unit cost level and the competitiveness of different reliability improving investment strategies. Since also the electricity distribution reliability of the different investment strategies is studied and presented, the distribution companies can use the results of this thesis to find out how they can benefit from the regulation by implementing investment strategies which allow a fair compensation for electricity distribution reliability improvements. The regulating body could see the impacts of the second regulatory period on different investment strategies and thus prepare for the third regulatory period.

For the calculation of the reliability and economic indices in medium-voltage distribution systems the sectionalisation concept is further developed. The concept takes notice of the difference in switching and fault clearing time of different component groups which depend on the mutual location of fault and load sections as well as the protection scheme of the component groups. The calculation method introduced and used for inhomogeneous distribution systems utilises the concept introduced for homogenous networks as a building block.

2 THE THEORETICAL FRAMEWORK

2.1 Literature review

Since there have been no incentives to invest in the improvement of the medium-voltage distribution system reliability, the reliability indices of the distribution systems have not improved in recent years. But customers with many digital equipment request better quality of supply. This chapter gives a literature review of the topics mentioned in the introduction, as having a strong influence on the performance of the Finnish medium-voltage distribution systems, especially the electricity distribution reliability. Issues to be considered are the electricity market, cost efficiency in electricity distribution investments, distribution system consequences due to underground cabling of electricity lines, substation automation, feeder protection optimization, and feeder automation.

2.1.1 The Finnish electricity market

The electricity market in Finland was deregulated in 1995 as a result of the first Finnish Electricity Market Act (386/1995). The act was introduced to comply with the requirements of the European Union Directive (96/92/EU). At first competition was introduced to production & wholesale, but in 1998 all retail customers were able to choose their electricity supplier while electricity networks remained regulated natural monopolies. (Viljanen, Tahvanainen & Partanen 2007)

The electricity network companies have a universal service obligation which in legislation is translated to an obligation to connect. The network companies also have to develop their distribution systems, exercise reasonable pricing policies and provide customers with suitable service quality. According to the conditions specified in the network licenses the network companies have franchised monopoly positions in their operating areas. The regulator assesses the reasonableness of pricing and network access conditions and creates incentives for efficiency and service quality improvements. In doing this the regulator should enable and encourage the electricity network companies to carry out necessary investments. (Viljanen et al. 2007)

The Finnish regulation light-handed ex post rate-of-return regulation became legally binding in year 2000. Following the Directive 2003/54/EU the legislative amendments of 2005 to the Finnish electricity market legislation were mainly concerned with the practices applied in economic regulation of the distribution business introducing a more ex ante approach towards economic regulation with incentive schemes implemented in the regulatory system. (Viljanen et al. 2007: 1)

According to the guidelines for the Finnish second supervision period of 2008–2011 the electricity distribution quality influences the economy of the distribution companies in two ways. First, the regulation authority sets a company-related efficiency improvement obligation, which consists of a company-related improvement target and a general improvement target. Second the regulation authority calculates for every distribution company a reasonable profit level which regulates the price setting of the companies. (EMA 2008)

In his doctoral thesis, Honkapuro (2008) analyses the directing signals of the performance benchmarking and incentive regulation in the Finnish electricity distribution sector. By studying the incentives for distribution system investments and quality improvements he finds the generating mechanisms of the directing signals that efficiency benchmarking creates for electricity distribution companies. He also created an industry-specific methodology for analysing the directing signals of the regulatory benchmarking of the electricity distribution companies and implements the created tool and methodology in practice by analysing and developing the regulatory framework from the directing signals point of view.

The main statement of the thesis of Honkapuro is that the development of the regulation and benchmarking model cannot be carried without considering the practical directing signals for regulated companies. Based on this finding, a method for analysing the directing signals of the regulatory benchmarking was developed. If the directing signals of the economic regulation are not analysed during the development of the model, the regulated companies may be provided with unintended incentives for distribution system investments, which are not in line with the general principles of the distribution system design, i.e. minimizing the total cost of electricity distribution during the lifetime of the distribution system.

The research methodology applied by Honkapuro is theoretical analysis and the research approach is heuristic while the research is characterized as a case study. The results of his study have played a key role in the development of the Finnish regulatory model.

In addition, Honkapuro has concentrated on the evaluation of the directing signals of the regulatory framework. Yet the actual effects of these signals on the distribution systems, for instance network topology or preferred components, are not considered in a large scale. Hence, an evaluation of the regulatory effects on the long-term planning of distribution systems would be an interesting research topic.

2.1.2 *The cost efficiency of electricity distribution investments*

Hyvärinen (2008) defines the relation between electrical networks and economies of load density. The objective of his work was to quantify the effects of exogenous factors on the network cost, particularly the effect of load density and other factors in close relation to it. The whole density-range from sparsely populated rural areas to crowded city-cores is covered with specific issues concerning the urban areas with highest load densities.

The research method applied by Hyvärinen is an Engineering Economic Analysis (EEA). The basic steps of the implemented analysis method are:

- Description of the supply task including the relevant characteristics of the service area.
- Network generation.
- Monetary assessment of the generated asset structure including operational and maintenance costs.

The outcome of the research of the model network evaluation procedure carried out by Hyvärinen are optimal substation densities and corresponding network volumes for the given range of HV/MV substation area energy density and the modelled area types. Other outcomes are the cost level analysis and the cost structure analysis. Also a model network with computed results and compared corresponding data from actual substation service areas are presented.

As the main contribution to the field, Hyvärinen presents a new method, which enables the evaluation of the effect of external factors on the whole network cost from low voltage (LV) connections up to extra high voltage (EHV) substations. The model network approach is tested in evaluating and estimating the reliability indices through case studies and possible mitigation strategies are explored.

Lassila, Kaipia, Partanen, Järventausta, Verho, Mäkinen, Kivikko & Lohjala present a comparison of different electricity distribution investment strategies where the network lifetime total cost is minimized. The objective of the work was to find out how the reliability of electricity distribution can be improved by using different technologies and development strategies and what the benefit and cost would be for the end customer. (Lassila et al. 2007)

The development goals evaluated by Lassila et al. were:

- Decreasing the average number of faults (SAIFI) by 50 %
- Decreasing the maximum number of faults by 50 %

The development strategies where:

- Traditional strategy with old solutions
- Optimised MV network with MV lines next to roads and 1 kV lateral lines
- Optimised MV and LV network with MV lines next to roads
- 1 kV lateral lines and LV underground cabling
- Full-scale underground cabling

In his doctoral thesis, Lassila has developed a methodology for strategic planning of rural electricity distribution networks (Lassila 2009). In the development work of the distribution companies, changes in the environment, electro technical requirements, reliability issues, ageing of distribution networks and the needs of end-customers, network owners and the distribution company are taken into account. Thus strategy-level questions such as the development of reliability of supply and what are the effects of different development options e.g. full-scale underground cabling on the price of distributed electricity and the owner's return on investment (ROI) are the main objectives of the work.

By implementing different network development strategies on actual electricity distribution networks, Lassila has produced a basis for the distribution companies to develop their own strategic planning. The developed asset management system, which includes a number of different calculation elements, starting from determination of feasibility ranges of specific network techniques to determination of the value of large network masses and reliability calculation, enables the understanding of the mutual interaction between different factors and strategy-related cost and reliability calculation.

The concept introduced in the work facilitates the distribution companies to recognize and prepare for factors that have an impact on the strategic development of distribution networks. This is done by presenting a methodology that assists in discovering how various changes in the operating environment may affect the investment decisions. The functioning of the concept of strategy process is verified by practical network development work in an actual distribution network company environment. Other contributions to the field are the introduction of an interactive way of thinking and working in the distribution business, the introduction of a calculation and analysis methodology needed in the strategy process. Although Lassila points out that the different investment strategies interact, he does not make this interaction transparent.

Also Marttila, Strande´n, Antikainen, Verho and Perälä present a study on alternative strategies for rural area distribution network development where several methods for improving reliability of electricity distribution are combined and the economic profitability of them evaluated. (Marttila et al. 2009)

In the first stage of this study the following strategies were compared to the existing strategy with overhead lines (OHL) and spark gap overvoltage protection:

- Light modular substations
- Light modular substations and line reclosing

Because light modular substations and line reclosing gave the lowest lifetime total cost it was chosen to be the strategy to which the following strategies were compared:

- Increased overvoltage protection
- Boosted forest maintenance
- Allocated cabling
- Covered conductors in urban areas

In this second comparison full overvoltage protection was the most cost-effective strategy to improve the reliability of electricity distribution. The research further evaluates the influence of major storms and the impact of climate change. According to the results the optimized medium and low-voltage network has the lowest lifetime total cost while full-scale underground cabling has the highest total cost and would increase the distribution tariffs by 30–50 % (Marttila et al. 2009).

Antila (2003) studied the implementation of distribution automation (DA) in Finnish distribution networks in order to minimize the economic and qualitative effects of outages and voltage sags. This is done by developing two rural and two urban medium voltage networks for the study of the implementation of three distribution automation solutions. The three distribution automation solutions were the centralized automation solution, the total automation solution and the protection mode. In the centralized automation solution network disconnectors are remote controlled. The total automation solution is a combination of centralized and local automation. In the protection model directional protection is utilized for the protection of a closed ring feeder.

In his thesis, Antila studied the influence of the automation models on the return of investment and the feasibility of four rural and urban networks. The profitability of the automation models is compared using the internal rate of return calculation method where the observation period varies from 5 to 20 years. According to the results of the study, automation of rural networks is reasonably profitable in a time frame of ten years except for the ring network of the protection model. In limited urban underground cable (UGC) networks interruptions and voltage sags do not justify automation while automation of large and versatile urban underground cable networks may be profitable.

Antila presents results, which show how cost-effective different automation levels are when implemented in rural and urban network environment. He also verifies that remote control and local automation is a cost-effective means of improving rural area electricity distribution reliability. Finally, he gives an effective solution for improving the electricity distribution reliability of urban underground cable networks.

Su and Teng (2006) present the methodology and results for the economic evaluation of the Tai-Chung distribution automation (DA) project. In the project different distribution automation functions, including feeder automation, trouble call management, load management and remote metering functions were implemented. For future extension purposes a calculation of benefits and costs before and after project implementation was performed by using value-based and present worth analysis to identify the most beneficial distribution automation functions in the implemented project. According to the analysis the benefit/cost ratio of the feeder automation functions was 0.737. The benefit of feeder automation functions was 95 % of the benefits of the whole project. Among the feeder automation functions fault management was the most economic with a benefit/cost ratio of 0.71 representing 92 % of the benefits of the whole project. The research results verify that improvement of fault management functions is one of the most cost effective ways to improve electricity distribution reliability. The authors admit that there is an uncertainty regarding network topology, load distribution, and switch location on the customer interruption costs and reduced revenues.

2.1.3 Network consequences due to underground cabling of electricity lines

Elfving et al. (2006) have shown that increasing the level of underground cabling increases the network reactive power, creates a need to increase the number of feeders and local earth-fault current compensation, creates higher zero sequence voltages and makes the protection of both short-circuit faults and high-impedance earth-faults more complicated. Combined central and local earth-fault current compensation together with careful selection of network components seems to be an optimal solution to handle the higher currents and problems related to increased use of underground cabling of medium-voltage networks. Problems related to underground cabling are the efficiency of the compensation equipment, the phase shift over the zero sequence impedance of the power transformers, detection of different earth faults and higher zero sequence voltages. The report also gives guidelines for network designers regarding the longest possible network with central earth-fault current compensation (CEFCC) and combined central and local earth-fault current compensation as well as rules of thumb on actions regarding higher zero sequence voltage, the possibility to compensate for capacitive fault currents, maximum touch voltage and relay protection of high impedance earth faults.

In the cable parts of earth-fault current compensated networks impurities and moist resulting from chemical reactions related to the insulation material ageing processes and also possible impurities originating from the cable manufacturing process itself can lead to intermittent earth faults. Intermittent earth fault can be characterised as a series of cable insulation break-downs initiated as the phase-to-earth voltage exceeds the reduced insulation level of the fault point and extinguishes mostly itself as soon as the fault current crosses zero for the first time (Altonen et al. 2003). To detect and isolate intermittent earth faults different detection methods have been developed, e.g. the spike detection method and the phase angle criterion.

2.1.4 Substation automation, feeder protection optimization and feeder automation

Lehtonen et al. (1995) present a proposal for the future distribution automation system in Finnish utilities. The benefit of different automation functions was analysed by cost benefit calculations for three rural and two urban distribution companies. The proposed future distribution automation system comprises different computer based IT systems in the control centre. At the primary distribution substation different measuring, monitoring and control functions are needed. Some centrally located distribution substations should be remote controlled and/or equipped with remote read fault indicators. Finally, also some customer automation (CA) functions, like automatic meter reading are suggested. The most important field of development was found to be the location and detection of faults, fault isolation and supply restoration. In urban areas only remote reading of fault indicators at the distribution substations was found to be cost effective.

Lågland et al. (2009), Nykänen (2010) and Roslund (2010) have studied the electricity reliability improvement by using remote controlled line reclosers in the networks in Ostrobothnia in Western Finland. They all conclude that remote controlled line reclosers are a cost-effective mean of improving all the three main reliability indices of rural/sub-urban networks. Typical payback times are in the area of under two years and the impact on the reliability indices of the feeder is on a distribution company level in the area of 10–20 % but on a feeder level from 25 % up to 50 %. The two first mentioned studies examine the network of the same distribution company and found that in 10–20 % of the feeders remote controlled line reclosers were cost-effective. Roslund found that by using eight line reclosers in thirteen feeders the reliability indices in the whole network could be improved with approximately 20 %. The number of line reclosers per feeder was one to two.

Soudi and Tomsovic (1997) present a binary programming optimization algorithm to optimize reliability indices with regard to type and location of protection devices. Constraints are circuit configuration and data, type and number of protection devices and coordination of devices. By translating reliability data and the feeder constraints into binary programming the problem is solved by using a commercial mixed integer linear programming package for computer calculation.

Fan and Zhang (2006) present an analysis of existing feeder automation solutions and introduce a practical approach which is an extension of the SA function. Existing feeder automation approaches are divided into semi-automatic solutions, distributed solutions and centralized solutions. The semi-automatic approach is based on built-in logics in feeder sectionalizing switches while the auto-switches in the distributed solution are configured with local intelligent logics for fault management. The centralized solution is a part of full DA where all the automatic switches are controlled by the control centre. The paper also describes a semi-centralized fourth feeder automation approach which is an extension of substation automation covering the feeders. This is done by extending the communication network to cover the automated feeder switches. The performance of the semi-centralized feeder automation solution is shown by describing the operation of the fault-management system in different fault scenarios.

Falaghi, Haghifam and Tabrizi (2005) present a research on how fault indicators affect electricity distribution reliability by modelling real distribution feeders. By using an algorithm, theoretical calculations were made with a computer software package. The variation of indices in different parts of the feeder and the location and number of fault indicators influence on the System Average Interruption Duration Index *SAIDI*, the Customer Average Interruption Duration Index *CAIDI* and the non-delivered energy can thus be calculated. According to the study *SAIDI*, *CAIDI* and NDE are all very sensitive to the location of the fault indicators. With increasing number of fault indicators *SAIDI*, *CAIDI* and NDE improve although the improvement decreases with increasing number of fault indicators. Thus there are an optimum number of fault indicators for each circuit layout with respect to the cost of the installed fault indicators.

Staszeski, Craig and Befus (2005) describe the implementation and the results of distributed feeder automation solutions in the distribution automation projects in ENMAX Power Corporation in 2004. The IntelliTEAM II is a fully automatic fault isolation and service restoration system which uses distributed intelligence and peer-to-peer communication for fault management. To maximize the restoration potential of feeders, ties to multiple circuits are used. Circuit configuration is made by the teams and coaches. A team is defined as a line segment bounded by two to eight automated switches, each of which can represent a different power source (Figure 4). Each team has a software coach, which uses voltage and current real-time data to develop a restoration strategy for healthy sections. Shared controls enables the teams then to co-operate implementing strategies and using rules prioritized and defined by the user maximizing circuit restoration.

In phase I of the distribution automation project 18 distribution feeders with a nominal voltage of 25 kV were automated with a resulting reduction in both *SAIDI* and System Average Interruption Frequency Index (*SAIFI*). The reduction in *SAIFI* is due to the fact that with advanced feeder automation the interruption time in un-faulted segments of the feeders can be reduced to less than one minute by service restoration.

According to Garcia-Santander (2005) currently used protection equipment fail to detect 30–50% of downed-conductor faults. Both current and voltage based fault indication methods are used. Signal processing and neural networks are used to increase sensitivity, but as sensitivity increases reliability decreases due to faulty operation during normal changes in the network. Distance calculations are only applicable for relatively low impedance faults.

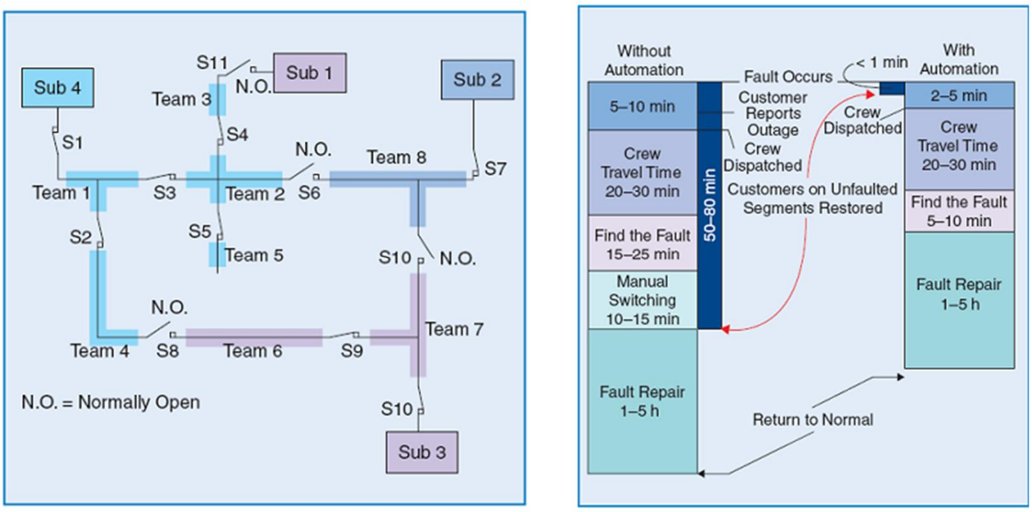


Figure 4. An example of IntelliTEAM II used to automate four open-loop distribution circuits (left). To the right supply restoration times are presented without and with advanced feeder automation (Staszeski et al. 2005: 58).

Bjerkan, Høidalen and Hernes (2007) present a method to detect and locate high impedance faults generated by downed-conductors. The line voltages at the low-voltage terminals of distribution transformers along the feeder are measured by the fault detectors. For detection, the changes in amplitude and phase of the measured voltages are used. Broken loops and blown HV-fuses can be detected by this method. Communication facilities, such as radio communication, Global System for Mobile Communications (GSM) or General Packet Radio Service (GPRS) communication, fibre or leased lines between the detectors and the primary distribution substation are needed. To locate and isolate the fault-site efficiently, the Supervisory Control And Data Acquisition (SCADA) system utilizes an algorithm which compares activated sensors with topological information of the feeder. The research project also included successful field tests.

2.1.5 Future trends

The final report of the visionary network project was published by The Technical Research Centre of Finland (VTT): Distribution Network 2030 Vision of the Future Power System (Kumpulainen et al. 2006). Currently, tremendous amount of investments are made for R&D work on intelligence, information technology (IT), high temperature superconductivity and hydrogen technology. The present areas of emphasis in the field of network technology are protection, automation, power electronics, microgrids, fast simulation and modelling. In the production area, focus of attention is the expanding production portfolio and the integration of distributed generation and energy storages. The research on network solutions is concentrated on simple networks without redundancy, networks with built-in redundancy, hybrid networks, and microgrids.

2.2 Network properties influencing the quality of electricity supply

Environmental conditions, the characteristics of the distribution system and the resources of the distribution company determine the electricity distribution reliability (Figure 5). Fault preventing investment strategies, like increased overvoltage protection and tree trimming, and the influence of climate change on the total outage costs have been studied by Marttila et al. (2009). The main attention of this study is, however, on the properties of the distribution system. It is therefore necessary to give a short overview on different system neutral grounding and wire systems as well as the different types of medium-voltage feeders.

ELECTRICITY DISTRIBUTION RELIABILITY		
ENVIRONMENT	DISTRIBUTION SYSTEM	RESOURCES
– terrain – population density – forestry – climate conditions – climate change	– voltage level – system neutral – load density – cabling level – redundancy – circuit configuration – automation level	– construction – operation – maintenance – economy

Figure 5. The main properties influencing the electricity distribution reliability.

The choice of system neutral grounding is a compromise between the size of earth fault currents and limiting of over voltages. It also influences the choice of earth fault protection. Solid grounding is a natural solution for a majority of four-wire rural networks. Neutral isolation is a simple and economical solution in rural overhead line networks. In compensated networks small earth fault currents may extinguish thus improving electricity distribution continuity. Impedance grounding is typically used in urban underground cable networks. Changes in environment, new knowledge and the development of technology and advanced protection schemes have challenged the original selections of system neutral grounding methods.

In addition to the system neutral grounding method, the network configuration influences distribution network reliability and protection. The economical radial and open ring (OR) configurations, which have the same *SAIFI*, are commonly used in rural networks. The open ring configuration has a better *SAIDI* than the radial network and is most common in the urban networks. In the link arrangement system (LAS), the healthy part of the faulted feeder can be connected to the feeder of the neighbouring primary substation thus improving *SAIDI*. Satellite (SAT) networks are used in sub-urban areas because of their economy.

The level of underground cabling is directly related to *SAIFI* because the fault rate of underground cable lines is about one half of that of overhead lines. In severe storms the fault rate of overhead lines increases dramatically while underground cable lines are weatherproof. On the other hand the repair times of underground cable networks may be longer than those for overhead lines. Different feeder automation methods can improve the electricity distribution reliability of the chosen network type. Fault indicators allow operators to quickly identify the location of a fault. Both reliability indices (*SAIDI*) and the cost of non-delivered energy can be reduced by the use of fault indicators. The effects of using fault indicators are sensitive to the type, location and number of fault indicators. Remote control is used to improve fault management especially in long rural overhead lines. Remote control of selected line switches and reclosers improves network *SAIDI*. With line sectionalisation the effect of a fault can be restricted to the faulted switchable zone thus improving both system average *SAIFI* and *SAIDI*. Natural sections are the trunk and the lateral lines of a feeder. The effects of line sectionalisation on the reliability indices and the outage cost are sensitive to the number and location of the line sections.

2.2.1 System neutral grounding and wire system

The system neutral grounding of medium-voltage networks vary from country to country, utility to utility and even from substation to substation within a distribution company. The network type, network width, load density and the quality of the grounding have influenced the choice. The network owners of the different countries have made their own independent choices regarding the system neutral grounding. In different countries and distribution companies the choice of the original system neutral grounding was made according to the information available at that time. Changes in the environment, new knowledge and the technological development of the system neutral groundings have shredded new light on the original criteria for the choice of system neutral grounding. As changing the system neutral grounding is a complicated and expensive process it should, if possible, be avoided. For example entire protection system has to be reset. Reasons for changing can however be the security and quality of the electricity distribution system (Fulchiron 2001). In Schwarzenbach in Germany, compensated networks are being replaced with low resistance earthed networks (Will & Schilling 2003). In France, Électricité de France (EDF) uses impedance earthed networks but plans to use earth-fault current compensation in overhead line networks (Griffel et. al 1997).

By using different system neutral groundings it is possible to utilize the advantages of different system neutral groundings. In Schwarzenbach the distribution network is operated as two different networks, the rural and the urban network (Figure 6). The rural distribution network together with the overhead line network of the urban distribution network is compensated. The urban network is low-impedance grounded. According to the operating experiences the low-impedance grounding of underground cable networks improves significantly the reliability of electricity distribution. Because the used grounding resistance is almost twice as cheap as a Petersen coil, low-impedance grounding is also cheaper than using a Petersen coil (Will & Schilling 2003).

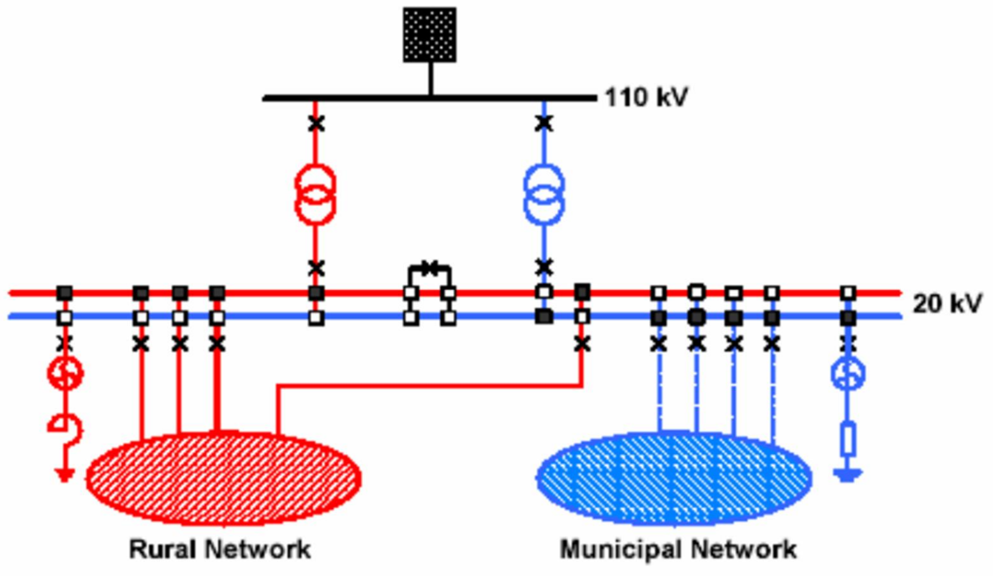


Figure 6. A compensated rural distribution network and a low-impedance grounded urban network in Schwarzenbach Germany (Will & Schilling 2003: 3).

In Italy ENEL has used earth-fault current compensation since 1998 as new system neutral grounding of distribution networks. The distribution company has also investigated the possibilities to change system neutral grounding during operation from neutral isolated to earth-fault current compensated and vice versa by using a system neutral grounding switching automation system and a new earth fault protection relay. An *intelligent electronic device* (IED) refers to a device that has versatile electrical protection functions, advanced local control intelligence, monitoring abilities and the capability of extensive communications directly to a SCADA system while a protection relay may need the assistance of a remote terminal unit (RTU) or communications processor to communicate with the SCADA supervisor or lack the control functionality (Strauss 2003: 48). Iberdrola in Spain has used both solid grounding and earth-fault current compensation since year 2000 (Zamora et al. 2003). In Austria earth-fault current compensation and short-time solid grounding is used (CIRED 1998: 3). Generally the system neutral grounding of medium voltage distribution networks is being re-evaluated both on a company and an international level. Earth-fault current compensation is in the interest of a growing number of distribution companies due to the use of new protection algorithms and systems of numerical protection relays. In Finland neutral isolated networks are transformed to earth-fault current compensated so that today over 50 % of the total line length is earth-fault current compensated. One of the main drivers is the restriction of the touch voltage during earth-fault conditions that is set in the Finnish national standards (SESKO: 2005).

2.2.2 The level and rate of underground cabling

Does underground cabling and reliability correlate for the different countries? In the Netherlands underground cabling of lines is 100 % and in the United Kingdom 81 % so a high level of service continuity could be expected in these countries (Council of European Energy Regulators 2005: 23). The Netherlands has the best *SAIFI* and United Kingdom is among the best (Figure 7b).

Finland has a very low level of underground cabling (12.7 %) and this also correlates to a relatively poor *SAIFI*. Norway, with a degree of underground cabling of 31 % has also a *SAIFI* clearly better than Finland. An exception is France with a degree of underground cabling of the same level as Norway but a significantly good *SAIFI*. According to the statistics, *SAIFI* in Finland is among the countries with the worst performance while *SAIDI* is of intermediate level (Figure 7a). A good explanation to the different level of these two reliability indices could be that feeder automation e.g. remote control of line switches is used quite frequently in Finland improving *SAIDI*. On the other hand, line reclosing is rarely used in Finland, which may to a certain extent explain the relatively bad *SAIFI* performance compared to other countries. *MAIFI* is expected to correlate to the degree of using overhead lines and reclosers (Figure 7c). In Finland substation reclosers are frequently used in overhead lines.

In rural areas, underground cable network configurations are often implemented using urban network solutions. By optimizing the existing underground network structures and components for a lower load density, costs can be optimized. This can be done for instance by modulating and selecting suitable network alternatives and solutions applicable to cable ploughing. In addition different component solutions, such as pole-mounted distribution substations installed at the pole foot, medium-voltage cable distribution cabinets, medium-voltage ring main units (RMU) and switching stations based on distribution substation technology, are needed. Distribution substations have also been developed further by integrating and adding new functions into them. An interesting example is the Transfix distribution substation with integrated protection and disconnection functions. The substation can also be provided with compensation equipment for local earth-fault current compensation.

The sub-urban/rural underground cable network requires additional new solutions for the compensation of the high capacitive earth-fault currents, network branching, voltage isolation, voltage measurement, system neutral grounding and backup supply arrangements.

a
b
c

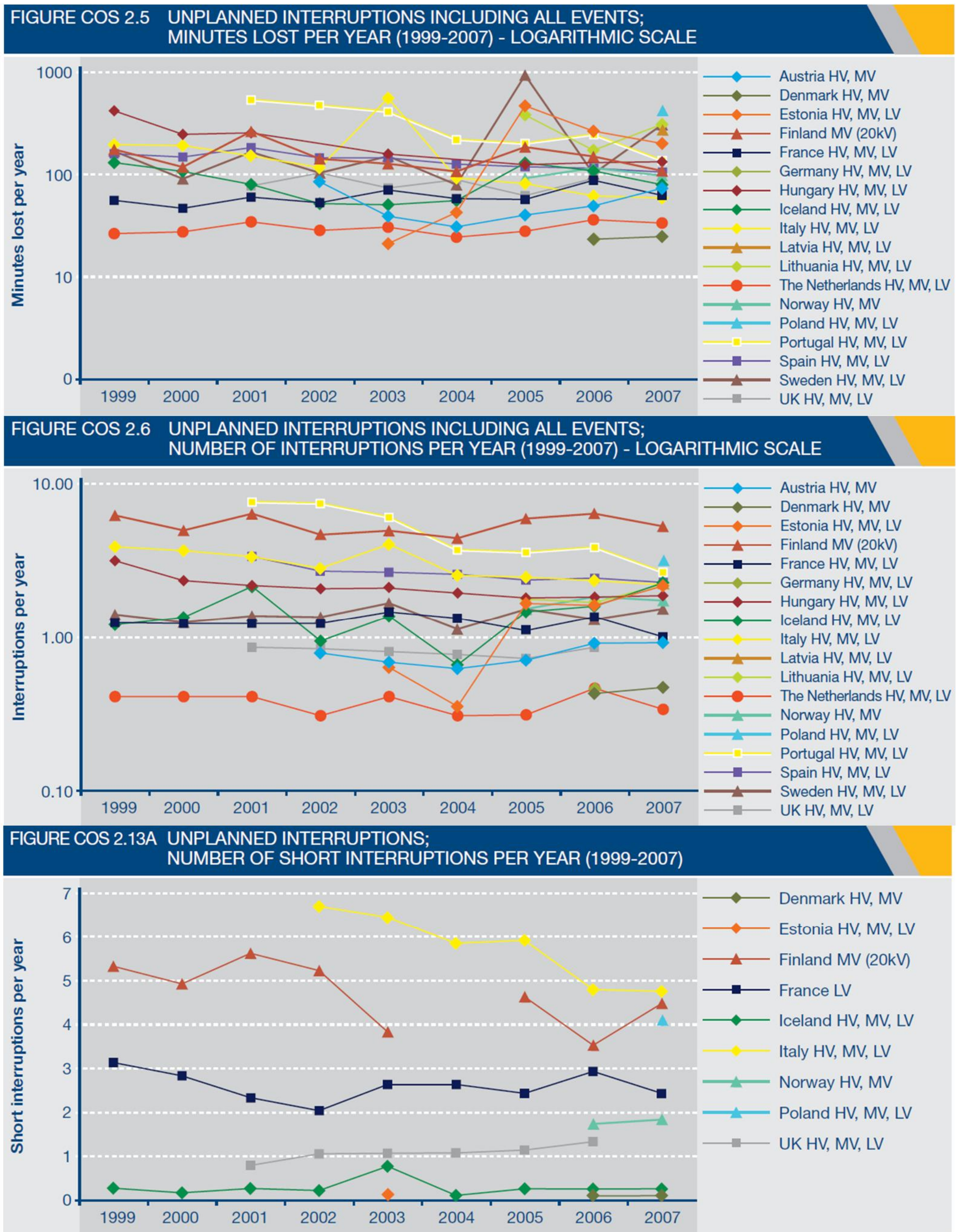


Figure 7. SAIDI (a), SAIFI (b) and MAIFI (c) in different countries. All events are included. In (a) and (b) the scale is logarithmic (Council of European Energy Regulators 2008: 138, 143).

Staffanstorps Energi Ab by the city of Malmö in South Sweden has decided to change over entirely to underground cable networks and has therefore developed a maintenance free modular cable network with similar functions as the overhead network. The distribution system consists of a ploughed-in underground cable network or an aerial cable network with hot-galvanized steel poles, an earth-fault current compensation system based on centralized and local earth-fault current compensation, an oil-filled branching module with elbow connectors, a nitrogen filled disconnector module with elbow-connectors provided with disconnectors, 50–315 kVA screened plug-in-type modular distribution substation and a backup power generation unit adapted to the modular system. During supply outages, the mobile backup supply generator units are employed for island operation of the network. The earth fault currents in the underground network in Staffanstorps Energi Ab are compensated both centrally and locally (Figure 8). Local compensation equipment is located at the distribution substations. (Göransson 2006)

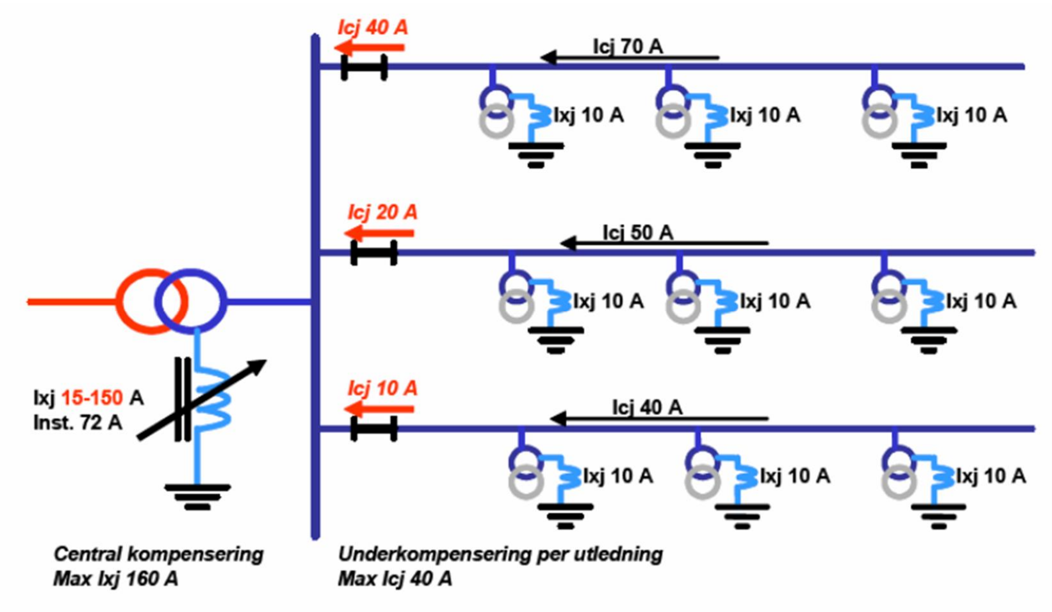


Figure 8. The earth fault current compensation system in the underground cable network of Staffanstorps Energi. The rated voltage is 22 kV and maximum capacitive current I_{cj} 500 A (Göransson 2006: 40).

2.2.3 Medium-voltage distribution network types

Medium-voltage distribution networks can be classified in different ways, e.g. networks with and without redundancy and standardised and not standardised networks. Distribution network types differ regarding voltage type (AC, DC) and level, network configuration and the share of distributed generation and power electronics integrated into the distribution network. In what follows an overview of the medium-voltage distribution network types that are used today in Scandinavia is given.

Configuration and capacity, which together create *switching capability*, reduce only the duration of interruptions that have already occurred. *Configuration* includes determination of both routing (feeder layout) and switch locations. *Capacity* refers to the current and voltage drop capabilities of the feeder pathways and ratings of the switches. (Willis 2004: 492) Configuration is the main characteristic that separates different distribution networks from each other.

Figure 9 presents a proposal for the classification of medium voltage distribution networks based on network configuration. Radial, open ring, link arrangement systems, and satellite networks are operated radial while closed ring networks and primary network systems are operated meshed. In rural areas, radial overhead or mixed line, link arrangement system and satellite networks are used while mostly open ring underground cable networks and primary network systems are used in urban areas.

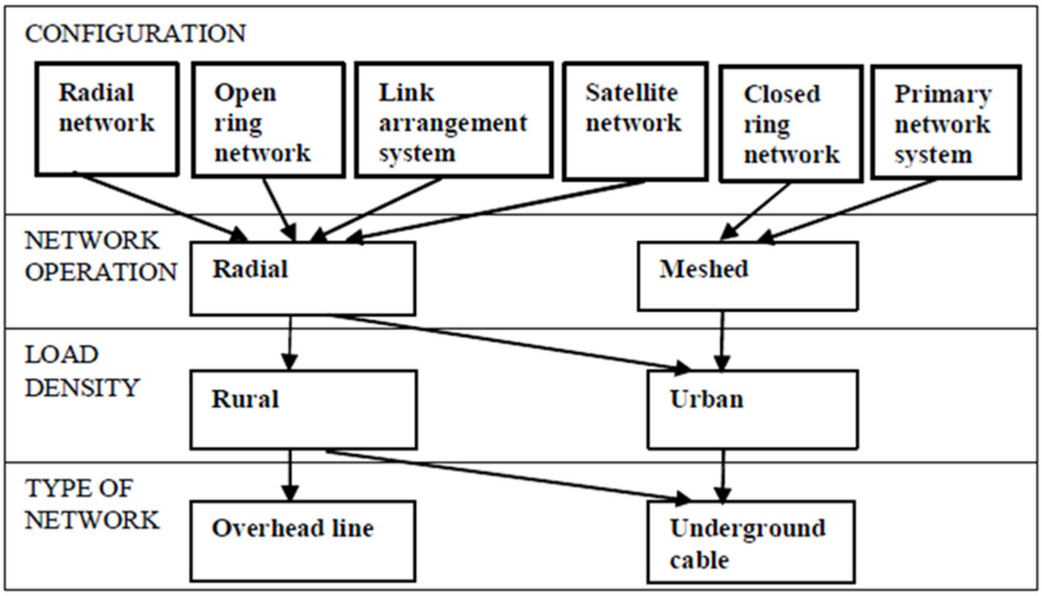


Figure 9. A proposal for the classification of medium voltage networks. (Långland & Kauhaniemi 2005: 1).

The use of radial networks enables a low-cost electricity distribution for small loads (10 kVA) to a large area (100 km^2). Radial networks are often used with overhead line and they are inexpensive to construct and simple and easy to operate (Figure 10). The electricity distribution reliability is however worse than for other networks. The annual interruption time grows when the load is located far away from the primary distribution substation. The advantages of radial networks can be utilized for large loads by using the expanded radial configuration to feed the distribution substations near the loads, which in turn are fed radially by the substations. (IEEE 1993: 37).

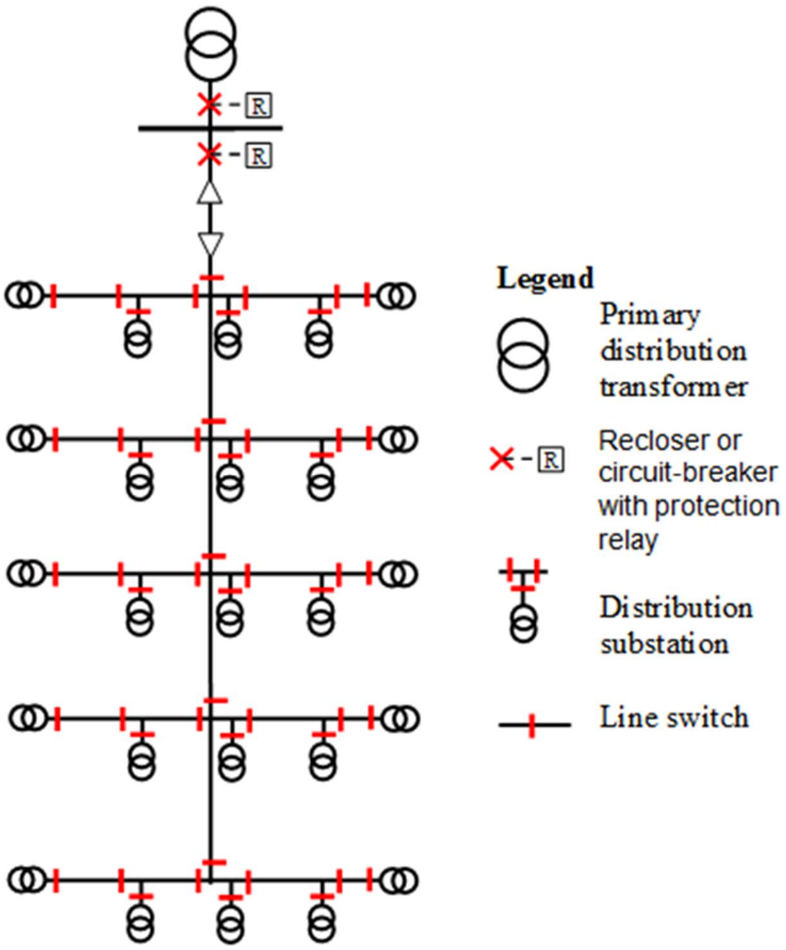


Figure 10. A medium voltage distribution radial overhead line feeder.

The effects of interruptions in radial networks are reduced by connecting two or more feeders together by normally open (N/O) disconnectors. The open ring network configuration is the most common underground cable net-work (Figure 11). The radially operated ring feeds about ten distribution substations. During a network failure, after the disconnection of the faulty part of the network, the normally open disconnector is closed to feed the healthy part of the network. The open ring network also often contains alternative feeding points within the network. The construction cost of the open ring network is however higher than for a radial network. The annual number of interruptions is the same as for a radial network while *SAIDI* is better than that for radial networks.

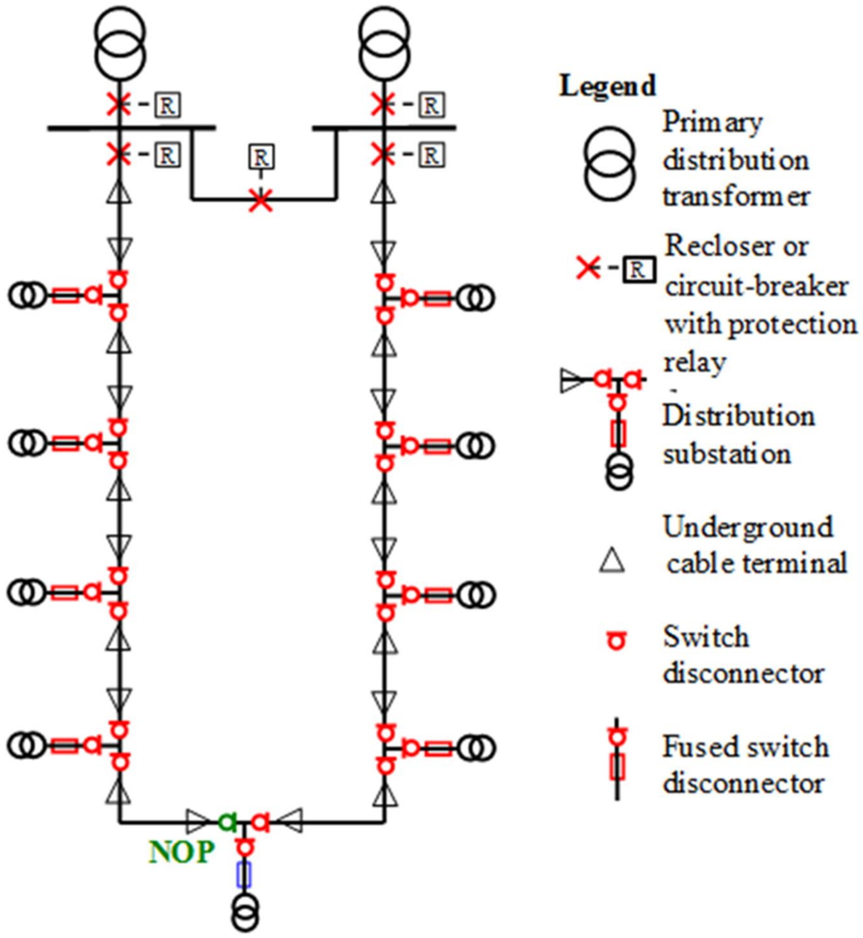


Figure 11. An open ring underground cable network.

To achieve even better electricity distribution reliability, a closed ring network can be used. In its most basic form, the open ring normally open switch is replaced with a normally closed line circuit-breaker, which opens when a fault occurs in one of its two branches. The average continuity of distribution can thus be improved by about a half (*SAIFI*). The closed ring network contains at least one remote controlled circuit-breaker for the isolation of faults (Sectionalising circuit breaker). A fault on the ring trunk line opens the primary distribution substation circuit-breaker and the remote controlled sectionalising circuit breaker and the operation of the healthy part of the feeder continues without any interruption.

A one transformer primary distribution substation busbar fault causes an outage in both branches of the open ring network. By connecting the feeders from two different primary substations to a link arrangement system the effects of a primary substation busbar outage can substantially be reduced (Figure 12). After the isolation of the fault the emergency connection from the neighbouring primary substation is established by closing the normally open point (NOP) disconnector. The availability of the link arrangement system corresponds to that of the open ring network, although it offers the ability to power transfer exchange between two neighbouring primary distribution substations thus improving the availability of emergency power transfer. Both the open ring network and the link arrangement system have an emergency connection. The link arrangement system network is however connected to two primary distribution substations, whose influence on the availability of the network is only marginal, because a primary distribution substation failure is rather rare.

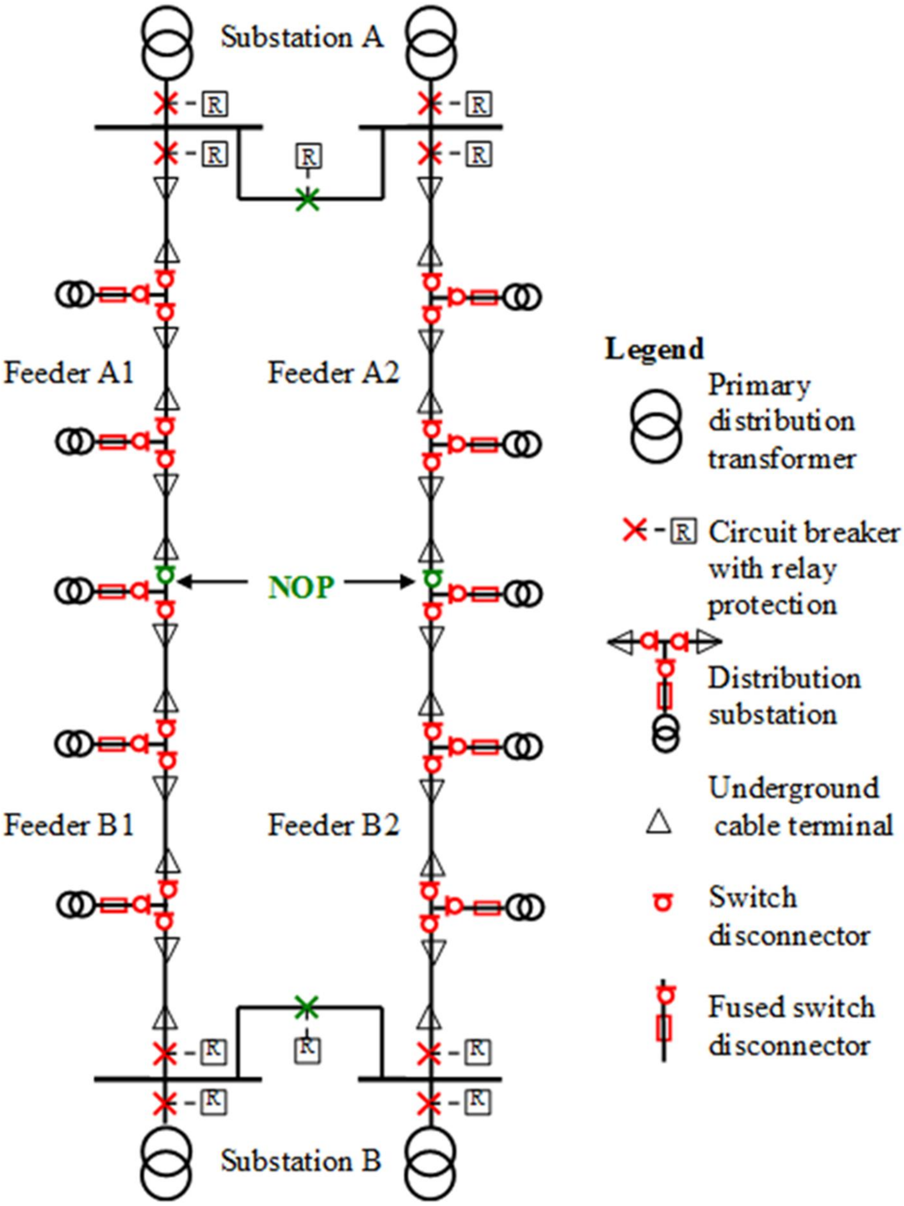


Figure 12. In a link arrangement system network feeders of neighbouring primary distribution substations are connected to each other by normally open points.

In practice the higher availability of the link arrangement system network is important, because in a primary distribution substation busbar failure and a primary distribution transformer failure it improves *SAIDI*.

The primary network system consists of feeders which are connected to the busbars of different primary substations in a way that all the feeder ends are connected to different substations (Figure 13).

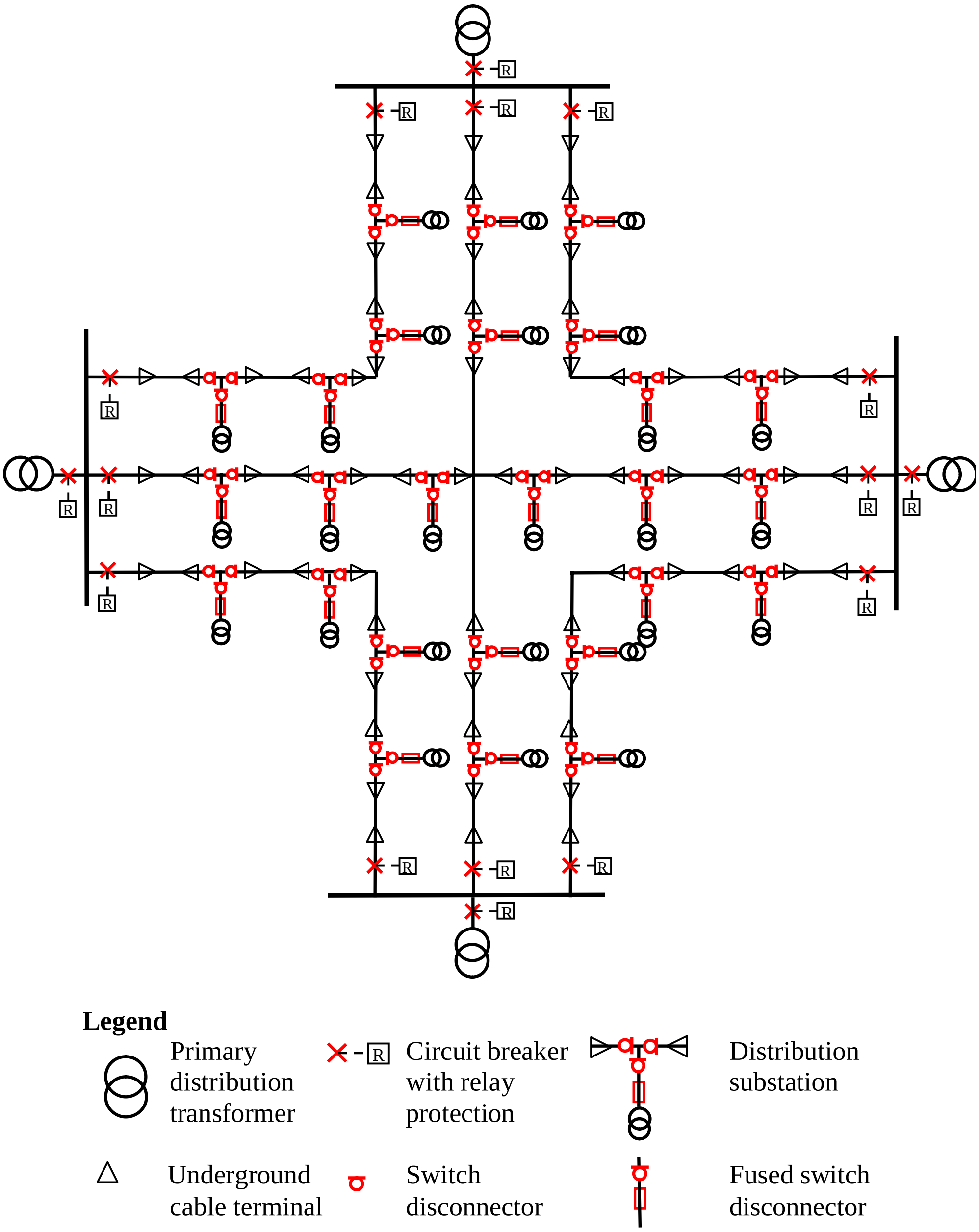


Figure 13. The basic structure of the primary network system. Adapted from Tsao 2003: 928.

Recent technology development has increased the suitability of the closed loop network to be used in electricity distribution. Circuit-breakers used in ring main units in distribution substations are based on sulphur hexafluoride (SF6) or vacuum technology. Micro remote terminal units, reliable radio- and distribution power line carrier (DPLC) communication and numeric relays have enabled the use of remote control.

In the satellite network the medium voltage is distributed to the satellite substations from the trunk line via fused switch-disconnectors in the coupling stations. A *coupling station* is a branching point on the medium-voltage trunk line, from where the satellite substations of the network are fed through fused switch disconnectors.

The small distribution transformers (≤500 kVA) in the satellite substations are protected with medium voltage fuses in the coupling stations and satellite substations (Figure 14).

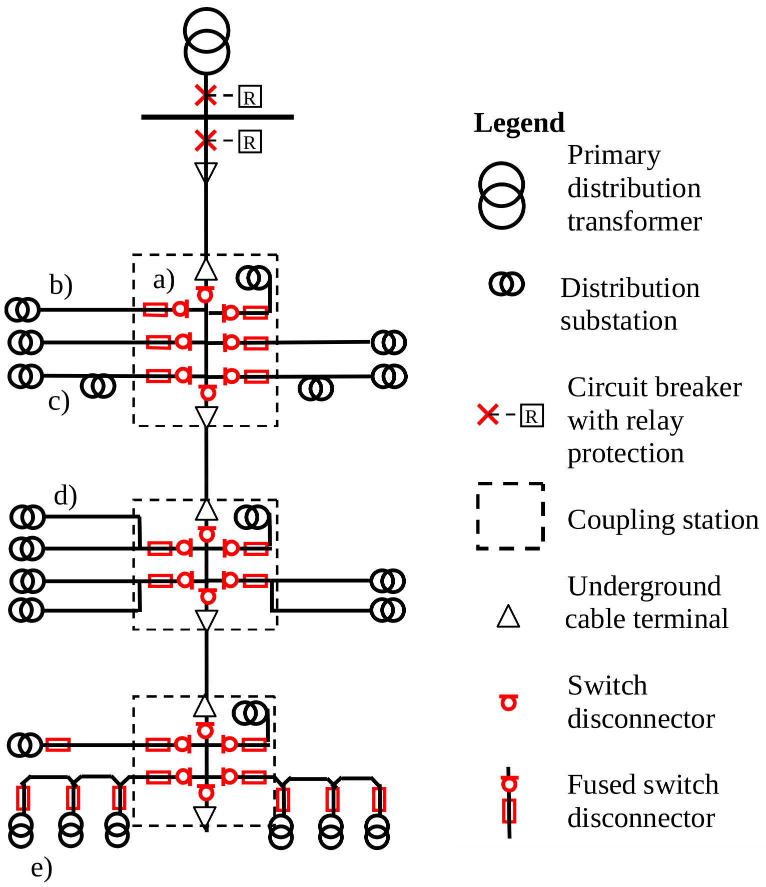


Figure 14. A satellite network containing coupling stations and satellite distribution substations. Adapted from SEF 1988.

The trunk underground cable line between two primary distribution substations is generally operated as an open ring. The coupling substations (a) distribute the energy to the satellite substations (b–e) from the trunk line. The small-sized *satellite cables* feeding the satellite substations originate from the fused switch-disconnectors in the coupling stations. A satellite cable can feed one (b), two (c) or three (e) satellite substations. The fused switch-disconnector can feed one (b, c and e) or two (d) satellite cables. The satellite transformer can alternatively be protected by integrated fuses or not (SEF 1988: 17). Thus the satellite feeder type is very adaptable to different needs

Due to small distribution transformers, distribution substations and cable areas, the satellite network is easy to install and assemble. It is also reliable because the medium-voltage fuses in the lateral lines of the feeder isolate the faulty lateral in case of a permanent fault in the lateral line while the operation of the healthy part of the feeder continues. The power losses and voltage drop of the satellite network is quite low because the medium-voltage network is extended near to the customers. The satellite networks used in residential areas in Scandinavia are 7.7–13.0 % more inexpensive than other open ring networks (SEF 1988: 11).

In urban areas, it is difficult to cost-efficiently increase the reliability of supply any further. Nevertheless, with only two medium-voltage feeders, the supply reliability can probably be raised to a new level; which may be realistic in the centres of large cities.

Medium-voltage networks feed a wide area with different load densities and power quality demand. One way to optimize the network type is to use different network configurations in different parts of the distribution area. An example is the network and primary selective network hybrid system which has been studied and piloted in Sao Paolo in Brazil where the high-cost network configuration gradually will be replaced by the primary selective hybrid configuration (Gouve'a, Costa & Brunheroto, 2005: 5).

2.2.4 System average performance and reliability indices

The manner of failure of an electricity distribution network can be treated by the series and parallel network concept. The components are said to be in *series* if only one needs to fail for the network to fail or they must be all up for network success. The components are said to be in *parallel* if they must all fail for the network to fail or only one needs to be up for network success (Wenyuan 2005: 71). Most networks in Finland today are operated as radial networks. A radial distribution system can be modelled using the series network concept (Figure 15).

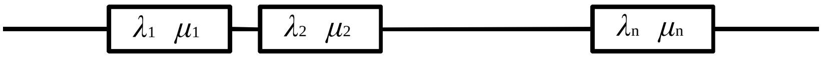


Figure 15. The series network concept (Wenyuan 2005: 72).

The availability of a two-component series network is:

$$A = A_1 A_2 \,, \tag{1}$$

where

A = availability
U = 1-A = unavailability

Thus

$$(1-U) = (1-U_1)(1-U_2) \tag{2}$$

By definition (Wenyuan 2005: 15):

$$U = \frac{\lambda}{\lambda + \mu}, \tag{3}$$

where

λ = expected failure rate
μ = expected repair rate.

By substituting Equation (3) into (2), we obtain:

$$\left(1 - \frac{\lambda}{\lambda + \mu}\right) = \left(1 - \frac{\lambda_1}{\lambda_1 + \mu_1}\right)\left(1 - \frac{\lambda_2}{\lambda_2 + \mu_2}\right) \tag{4}$$

In a series system (Wenyuan 2005: 72):

$$\lambda = \lambda_1 + \lambda_2 \tag{5}$$

By definition (Wenyuan 2005: 15):

$$\mu = \frac{1}{t_r}, \tag{6}$$

where

t_r = repair time

By substituting Equation (5) into (4) and applying the relationship in Equation (6), the equivalent repair time for the series network can be calculated by:

$$t_r = \frac{\lambda_1 t_{r1} + \lambda_2 t_{r2} + \lambda_1 t_{r1} \lambda_2 t_{r2}}{\lambda_1 + \lambda_2} \tag{7}$$

Because $\lambda_1 t_{r1} \lambda_2 t_{r2} << \lambda_1 t_{r1}$ or $\lambda_2 t_{r2}$ (Wenyuan 2005: 99), we can further estimate:

$$t_r \approx \frac{\lambda_1 t_{r1} + \lambda_2 t_{r2}}{\lambda_1 + \lambda_2} \tag{8}$$

With i number of series components (Lakervi et al. 1996: 74), we can define that the expected annual outage time U_j is:

$$U_j = \sum_{i \in I} \lambda_i t_{ij} , \tag{9}$$

where

λ_i = failure rate of component i

i = the set of the components whose failure results in an outage at a given load point j

t_{ij} = the outage time at the given load point j caused by a failure of component i(h)

and the average outage duration r_j is:

$$r_j = U_j / \lambda_j , \tag{10}$$

where

λ_j = outage rate of load point j

The non-distributed energy E_j (NDE) is:

$$E_j = \lambda_j r_j P_j , \tag{11}$$

where

P_j = the average outage power at load point j

The average power P_j is:

$$P_j = \frac{W}{T} , \tag{12}$$

where

W = total energy demand in period of interest
T = period of interest

In Finland MV distribution network outage statistics are collected on distribution transformer substation level, and therefore they are not related to real customer level information. System-level indices are used, which are based on the number of distribution substations affected by the interruptions. This is shown by adding the prefix T before the indices, e.g. *T–SAIFI*, *T–SAIDI* and *T–MAIFI*. The indices that are applied in this thesis do not include low voltage network outages are calculated as (Partanen et al. 2006: 18, 19):

$$T - SAIFI = \Sigma mpk_i \, / \, mp \,, \tag{13}$$

where

mpk_i = the number of the distribution substation areas that are influenced by outage i
mp = the total number of the distribution substation areas in the distribution area

$$T - MAIFI = \Sigma mpk_i \, / \, mp \,, \tag{14}$$

where

mpk_i = the number of the distribution substation areas that are influenced by the momentary outage i

$$T - SAIDI = \sum_{i=1}^{z} \sum_{j=1}^{x} mpk_{ij} \times t_{ij} \, / \, mp \,, \tag{15}$$

where

z = the number of outages
x = the number of different outage durations related to a certain outage
mpk_{ij} = the number of distribution substation areas in the areas where the outage duration was t_{ij}

In Finland energy weighted substation level reliability indices are used for benchmarking purposes.

2.2.5 Summary

Distribution network types differ with regard to voltage type and level, network configuration, backup connections, feeder automation, protection and the share of distributed generation and power electronics integrated into the distribution network. Medium-voltage distribution networks used differ from simple network configurations like the radial network, the open ring network, the link arrangement system and the satellite networks to networks with extra redundancy. Simple network configurations are mostly used in rural areas where the demand for electricity distribution reliability has so far not been so high. In city-area networks with extra redundancy are used to achieve extremely good electricity distribution reliability. Hybrid networks consisting of two different network types can be used to feed areas with different levels of load density or when an existing network configuration is changed to another. Alternating current and direct current microgrids are the solutions for electricity distribution for special customer groups. Direct current distribution networks are a natural solution for low voltage networks when expanding DC applications on the low voltage grid. As this study includes only low and medium load density area networks only simple and relatively low cost network types are included. Extremely reliable power delivery systems are analysed in an EPRI report (CEIDS 2002).

2.3 Use of feeder automation to improve electricity distribution reliability

Distribution automation systems have been defined by the IEEE as systems that enable an electric utility to monitor, coordinate, and operate distribution network components in real-time mode from remote control centres (IEEE 1988). Distribution automation comprises substation automation, feeder automation and customer automation (Figure 16). Feeder automation functions treated in this work are supervisory control and data acquisition (SCADA), fault location and fault detection, isolation, and service restoration.

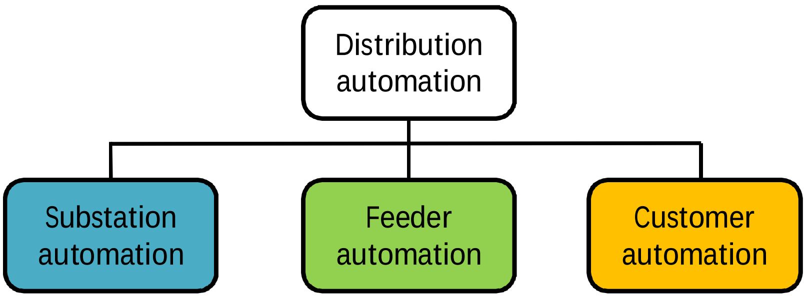


Figure 16. The components of distribution automation.

The average reliability of electricity distribution can be improved even after an emergency, caused of a fault, by removing a transient fault and limiting the influence area and duration of a permanent fault with distribution automation. With feeder automation schemes, such as automatic loop sectionalising, automatic feeder transfer and remote control, the average distribution substation related reliability indices can be improved. Technological constraints, e.g. information technology (IT), and high cost compared to the benefits, have restricted the use of automation in improving the electricity distribution reliability of both rural and urban networks. Technological progress, privatisation, growing electricity distribution quality awareness, and a greater dependability on uninterrupted electricity distribution have generated pressures for improving the electricity distribution quality.

Switching capability enables a feeder system to transfer load to alternative service routes thus reducing interruption time by permitting service to be restored in advance of repair. Thus switching doesn't influence *SAIFI*, but can improve *SAIDI*. Switching capability is achieved by arranging the configuration of a feeder and adjacent feeders so that they can be re-switched providing sufficient line capacity during contingencies. Good switching capability leads to reduced *SAIDI*, particularly in systems with long repair times as in urban underground networks. Switching time has two impacts. First, faster switching will reduce *SAIDI* when configuration and capability can provide alternative paths for service during certain contingencies. Furthermore, automation used for improving switching times (fast switching) may reduce the duration of interruptions below the *MAIFI* threshold so that those customer interruptions that would have been counted as *SAIFI* and *SAIDI* are counted only as *MAIFI*. (Willis 2004: Chapter 14)

> *Switchable zones* are contiguous portions of a feeder that lie between switches. Each zone can be individually shifted to one or more alternate feed sources, providing a measure of improved reliability. (Willis 2004: 487)
>
> Contingency support can also be made by splitting a feeder into several switched zones which are distributed among neighbouring feeders during a contingency when a fault has occurred in the distribution system. Then the additional load transferred to any adjacent feeder is only a fraction of a full feeder load. (Willis 2004: 510)

According to a survey (Popović et al. 2005: 1) line reclosing is only used in some European countries. In the Finnish medium voltage distribution networks line reclosing is not much used, because the experiences with line-oil-minimum circuit-breakers are quite bad due to malfunctions in severe weather conditions and bad operation and service experiences.

Most European countries use automation for fault management. This also applies to Finland where remote indication, measurements and remote control in rural area distribution is frequently used (Figure 17).

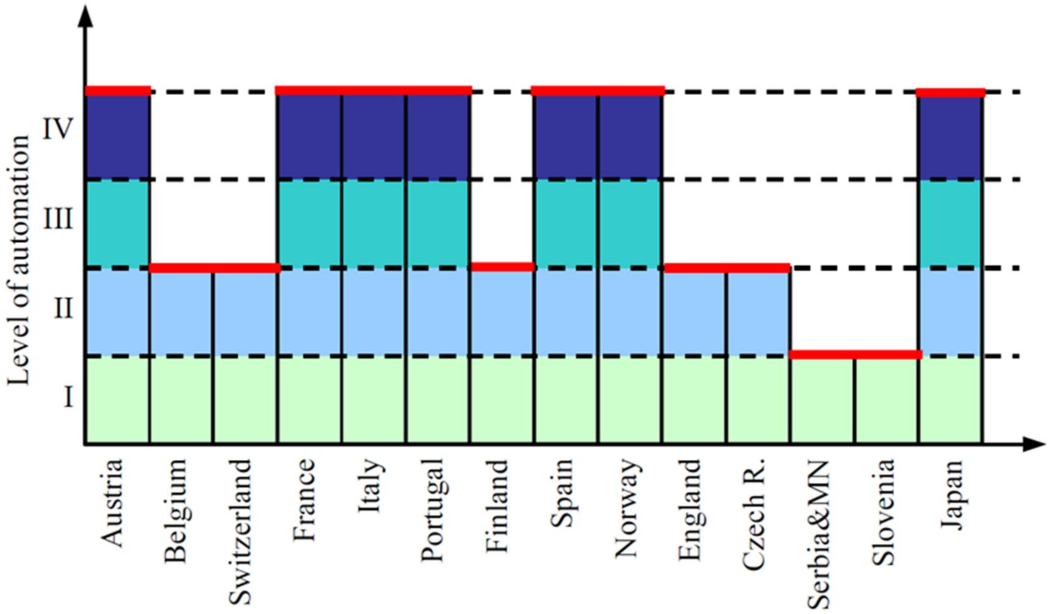


Figure 17. The level of automation in some countries. Levels: I = Fault detectors with local and/or remote indication, II = Remote control of switchgears, remote indication and remote measurements, III = Application of local automation (reclosers, auto-sectionalisers, change-overs), IV = Combination of remote control and local automation (Popović et al. 2005: 1).

Minor utilization of line reclosing is not directly seen in the electricity distribution reliability indices. According to the Third Benchmarking Report (Council of European Energy Regulators 2005), the average value of *SAIFI* in Finland in 1999–2004 was 4.0 1/a and the ranking in the reported ten countries was number nine. According to a similar calculation, the average value of *SAIDI* in Finland in the same time period was 3.9 h while the ranking was number eight. An explanation for the behaviour could only be found by calculating the *CAIDI*. *CAIDI* for the Finnish networks was 0.94 h and the ranking second. This good ranking may be explained by the frequent use of remote control and the rare use of line reclosing resulting in a relative good *CAIDI* even if *SAIFI* and *SAIDI* were relatively poor.

Finnish medium-voltage distribution networks generally consist of the following switching and protection devices:

– A substation circuit-breaker or recloser

- A number of manually and a few remote controlled pole or line switches
- Fuses for distribution transformer protection in underground cable feeders

Most medium-voltage networks in Finland are mixed line networks consisting of both underground cable and overhead line feeder sections. In overhead line feeders the substation recloser is equipped with high-speed auto-reclosing (HSAR) and delayed auto-reclosing (DAR) functions. Pole or line switches are used in the trunk and the lateral lines for normal switching and fault management. The switches are mostly manually operated, but in strategic places of the feeder remote controlled switches or switch groups are also used. Pole or line switches are single switches or switch groups in the network with a density of 0.7–1.0 switch/km. In service and outage situations, the pole switches are operated to make the required connections. With the help of pole switches the network is divided so that the outages influencing the loads affect only a small area and the outage duration is as short as possible. With manually controlled pole switches the network faults can be isolated to a smaller area, but especially with remote-controlled line switches the faults can be found and isolated and service restored faster. Normally open point switches are used between two adjacent feeders in open ring networks and in link arrangement systems between two feeders originating from neighbouring primary distribution substations.

2.3.1 Remote control of switches

The duration of outages can be shortened using manually or remote controlled components, while automatic control of components also influences the average outage frequency (Table 1). Automatically controlled components, like line reclosers, sectionalisers and fuses decrease the number of customers involved in an outage by automatically isolating the faulty section. They also reduce the average outage frequency for the customers on the feeding side of the fault. But automation may also influence power distribution quality by increasing the number of short duration interruptions (*MAIFI*) and voltage dips.

The duration of outages can be shortened with remote-controlled line switches. By remote-control the control time of the line switches can be reduced from typically several tens of minutes to some minutes. This includes both the isolation of the faulty section and service restoration to the healthy parts of the feeder. Indirectly, the use of remote-control increases the transmission capacity of the network by quickly enabling the use of complicated reserve connections in network disturbances thus enabling the use of the whole network capacity and reducing or postponing the investment needs.

Table 1. The influence of the control method of components on the electricity distribution reliability indices (Adapted from Soudi & Tomsovic 1999:220).

Control system	***SAIFI***	***SAIDI***	***CAIDI***	***MAIFI***
Automation	x	x	x	x
Manual control		x	x	
Remote control		x	x	

Network central branching distribution substations and normally open points are typical locations for remote-controlled switches. A remote-controlled switch includes a load-break switch, motor control equipment, control electronics, communication radio and voltage supply. Depending on the number of remote-controlled switches (1–4) the investment cost is 16.4–40.9 k€ (EMA 2010).

Because the average length of Finnish rural feeders is relatively long (31.6 km) remote control is very efficient in reducing the outage times. Long overhead line feeders in rural areas are often equipped with remote-controlled line switches (Figure 18). Most of the remote-controlled line switches are located at pole substations, but some pad-mount substations are also equipped with remote-controlled line switches.

Figure 18. A distribution substation with SF6-insulated pole load-break switches in Lapland in Northern Finland.

2.3.2 Sectionalisation of feeders

Protecting a feeder often involves some sectionalisation to ensure adequate detection and coverage of faults.

> *Sectionalisation* divides a feeder into sections in order to isolate faults or equipment malfunctions and thus minimizes the portion of the feeder circuit that is put out of service (Willis 2004: 487).

This is done by minimizing the influence of an outage or component malfunction when breakers, fuses or other protective devices operate to isolate a fault. Sectionalisation uses equipment that is automatic and nearly instantaneous to isolate faults and mal-functions. Different network types need different sectionalisation schemes, and require different amounts of contingency margin to assure sufficient capability. With good sectionalisation, planners can improve not only *SAIFI* and *MAIFI* but also feeder-related *SAIDI*. Differing from configuration and capacity sectionalisation affects reliability only at the feeder level. It has only an intra-level reliability impact, and offers no improvement on reliability concerns associated with failures or outages at the sub-transmission or substation levels. (Willis 2004: 483, 487–488, 492)

Fault sensing in sectionalisation can be based upon loss of voltage or the existence of over-current when a microprocessor-based switch control initiates a program to reconfigure the network. Some circuit-breaker sectionalisation has been used in the Finnish rural overhead line networks by using minimum-oil pole circuit-breakers equipped with primary over-current relays. Otherwise, circuit-breaker line sectionalisation has not been very common either in overhead line or under-ground cable networks. According to Willis sectionalisation can be done purely for protection purposes, to improve reliability or to loop feeders.

Sectionalisation done purely for protection purposes

When the minimum expected fault current at the end of the feeder is less than the load current at the substation, a single device cannot protect the entire feeder and protection sectionalisation is needed. Protection sectionalisation involves arranging protection schemes and protective devices locations so that they isolate problems with a minimum of interruptions to customers (Willis 2004: chap14).

In Finland the primary distribution substation protection can mostly handle all the faults in the feeder because the feeders are relatively short. Because the networks are neutral isolated or compensated, a sensitive earth-fault protection is needed. Only substation protection is generally used in Finnish medium voltage networks making the distribution system easy to operate (Figure 19: substation recloser).

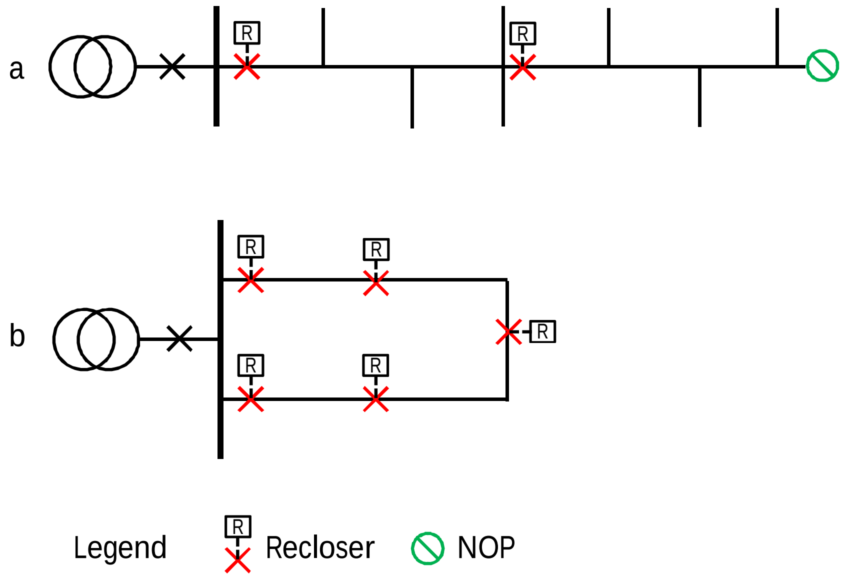


Figure 19. Sectionalisation added to improve reliability by the use of line reclosers in a radial (a) and an open ring feeder (b).

Sectionalisation added to improve reliability

Installing a line recloser halfway downstream of the feeder protects the upstream customers from supply interruptions caused by faults downstream of the line recloser (Figure 19 a). Sectionalisation by line reclosing reduces thus the average outage frequency for the customers on the feeding side of the fault improving the average outage frequency of the feeder by an average of 25 %. Since sectionalisation can also be used to improve average distribution reliability, there will be a potential to implement sectionalisation to utilize the power quality bonus of the present Finnish regulation model, e.g. with remote controlled line reclosers (Figure 20).

Figure 20. Sectionalisation of a rural network feeder with remote controlled line reclosers in the central regions of Finland.

Loop sectionalizing

A line recloser can be used in a normally open mode, as a loop sectionaliser, providing a normally open point between two feeders. After fault isolation the normally open point recloser can be closed by remote control to transfer the healthy part of the faulted feeder to the adjacent feeder. A normally open point recloser can be programmed to close if it sees no voltage on one side of it. The recloser scheme shown in Figure 19 b isolates a fault to one of the four sections in the two feeder loop shown, closing the tie to restore service to the healthy feeder section.

2.3.3 The influence of fault indication on the electricity distribution reliability indices

Fault indicators sense and indicate the through-passing fault current. Short-circuit indicators are used both for overhead line and underground cable networks while earth-fault indicators are used in overhead line networks. The indication can be based on manual or remote reading. Especially when fault indication is connected to a graphical information system (GIS) the time for fault location shortens remarkably. Fault indication is suitable for networks with and without distribution automation and for old networks. Because it shortens the time needed for fault location it doesn't affect *SAIFI* and *MAIFI*, but affects all the other reliability indices.

The number and location of fault indicators influence the improvement of the electricity distribution reliability indices. Regarding the location there is an optimum while increasing the number always improves the indices. With installation of n fault indicators on a distribution feeder, that feeder is divided into *n*+1 parts and fault location time for part *i* can be calculated theoretically by using equation (Falaghi, Haghifam & Osoulitabrizi 2005: 2):

$$T_i = \left(L_i / L\right) \cdot T_0 , \tag{16}$$

where

L_i = the length of part i of the feeder
L = the total length of the feeder
T_0 = the average fault location time of feeder without fault indication

2.3.4 Summary

Feeder automation includes the use of fault detectors, remote control of switches, remote indication and remote measurements, application of local automation and combinations of remote control and local automation. The use of local automation in Finland has so far not been used very extensively while remote control is used more frequently. Using remote control *SAIDI* has improved. Although line reclosing improves, not only average *SAIDI* but also *SAIFI* on a feeder level it is not utilised very much in Finland. It would, however, be important to know to what extent line reclosing can be used cost-efficiently to improve the electricity distribution reliability indices and reduce the total outage costs in Finland. *Intelligent sectionalisation* are a host of approaches that combine devices like line reclosers and sectionalisers with fuses in involved schemes that react to faults with a prearranged sectionalisation (Willis 2004: 537). With today's powerful computer processing units, new and cheap communication media and the new communication standard IEC 61850 the use of intelligent sectionalisation seems very attractive.

2.4 The influence of sectionalisation on the economic and reliability indices

As mentioned before, the second regulatory period of 2008–2011 has introduced both penalties and incentives for power quality. EMA calculates the power quality cost of each power distribution company and sets a target for power quality of each distribution company. The power quality costs included are the cost of non-delivered energy and auto-reclosing. So far the impact of feeder automation on the electricity distribution economical and reliability indices and the effect on the cost-effectiveness of other investment alternatives has been studied in case-studies. In this work an effort is made to reveal the impact of the interaction of feeder automation, distribution system and cabling with regard to economic and electricity distribution reliability indices on a general basis. The work starts by studying the performance of a homogenous medium voltage distribution network feeder with *n* number of identical zones. The feeder is said to be homogenous when the loads are evenly distributed along the whole feeder and the line configuration is similar along the feeder length. A sectionalising component is a component installed into the feeder to restrict the influence of an outage to the faulty sectionalisation zone (Figure 21). A sectionalisation zone is defined here as a section of the feeder between two sectionalisation components (remote controlled reclosers) and includes typically several lateral lines and manually and/or remote controlled line switches and distribution substations. Because the loads are evenly distributed the load in all n number of sectionalising zones is equal. The study is performed with the number of sectionalisation zones as a variable. The results are compared to a basic distribution system with only manually operated line switches. As a second comparison level is a feeder with two remote controlled line switches, one in the middle of the feeder trunk and the other at the feeder end. As most Finnish rural feeders have normally open points, the study is performed with a backup connection at the end of the feeder. To enable supply restoration by remote control the component at the normally open point is a remote operated line switch.

2.4.1 The homogeneous network model

There are many circumstances influencing the fault clearing time. The fault clearing time is dependent on the power flow direction, number and location of normally open points, switching and sectionalisation component type, number and location, fault section and load section location with respect to each other, cause of fault and the protection system.

In order to study the influence of sectionalisation the feeder sectionalising zones are divided into homogenous load and fault sections (Figure 21). A load/fault section is a feeder part consisting of components having the same annual fault frequency and behaving in the same manner under fault conditions. In a homogenous rural network feeder, typical load/fault sections are the trunk line load/fault sections (zT) and the lateral lines load/fault sections (zL). The feeder width k_W also influences the indices and is here defined as:

$$k_W = L_L / L_T , \qquad \textbf{(17)}$$

where

L_L = the total length of the feeder lateral lines
L_T = the total length of the feeder trunk line.
L = the total length of the feeder = L_T+L_L

It has been found out that after making a few simplifications it is possible to develop equations for calculation of the cost and reliability indices of rural/suburban overhead line networks as a function of the number of sectionalisation zones.

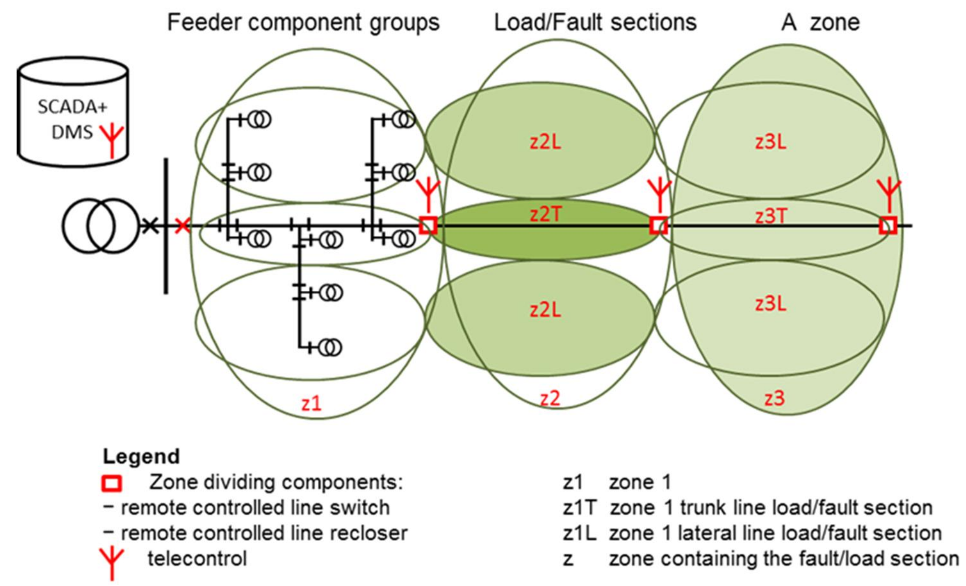


Figure 21. Creation of component groups, load/fault sections and zones for the purpose of calculating the economic and electricity distribution reliability indices of a homogenous overhead rural distribution feeder with the number of zones as variable.

First it is assumed that the network is homogenous regarding power density and fault frequency. After making the second simplification, which is setting the feeder average width k_w = 1 within each zone the application of the equations for the cost and reliability indices is quite straightforward (Figure 22). Here the trunk line of the feeder inside the distribution substation is specified to belong to the distribution substation. Thus a fault in the trunk line does not cause any outages longer than the switching time while a fault in the trunk line distribution substation causes an outage time equal to the repair time both for the substation and for all the substations in the lateral lines emanating from the trunk line distribution substation.

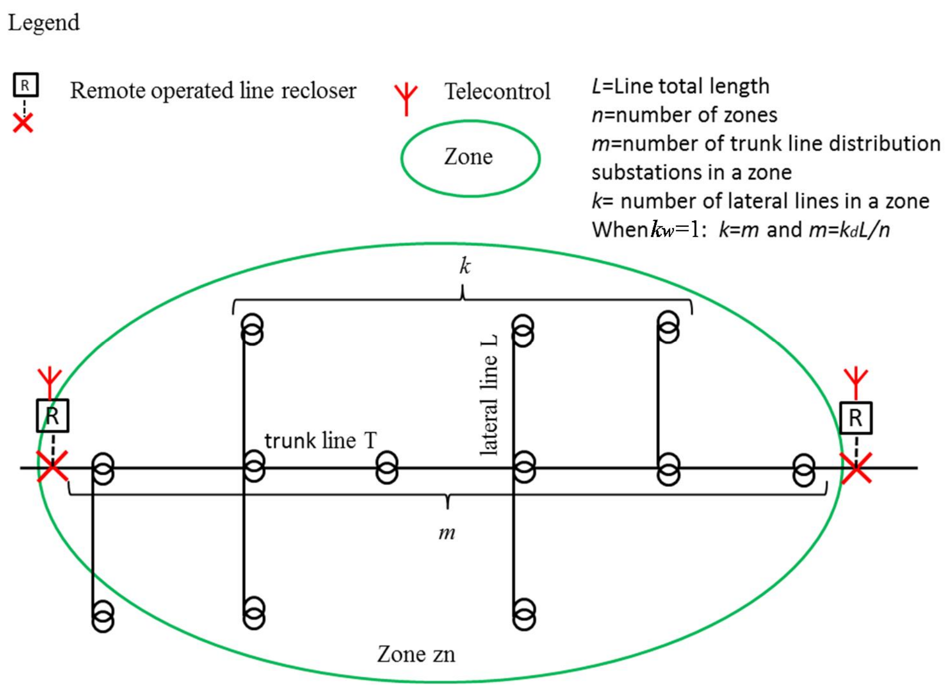


Figure 22. Definition of feeder configuration variables. On average one lateral line containing one distribution substation is fed from the trunk line distribution substations.

The study is performed to a feeder divided into different number of zones divided by remote controlled line switches or reclosers. Three configurations are studied (Figure 23):

– A feeder protected with a substation recloser alone and with only manually operated line switches along the feeder. This is the minimum protection of short rural feeders. It is also a suitable comparison level when choosing cost-effective feeder automation schemes for new medium and long feeders. (Figure 23 a)
– A feeder protected with a substation recloser and n number of remote operated line switches along the feeder trunk line, n–1 along the feeder trunk line and one at the normally open point, corre-

sponding to the present protection and feeder automation level of medium and long rural feeders (Figure 23 b)

– A feeder protected with a substation recloser and n number of remote operated line reclosers along the feeder trunk line, which corresponds to the future average protection and feeder automation level of medium and long rural feeders (Figure 23 c)

Thus the first two configurations can be used as comparison levels for the study of the benefits of the use of remote controlled line reclosers. To find out the impact of the number of remote controlled line reclosers the number is varied from one to five. The component at the normally open point is of the same type as the zone dividing component and the main component at the substation is always a recloser.

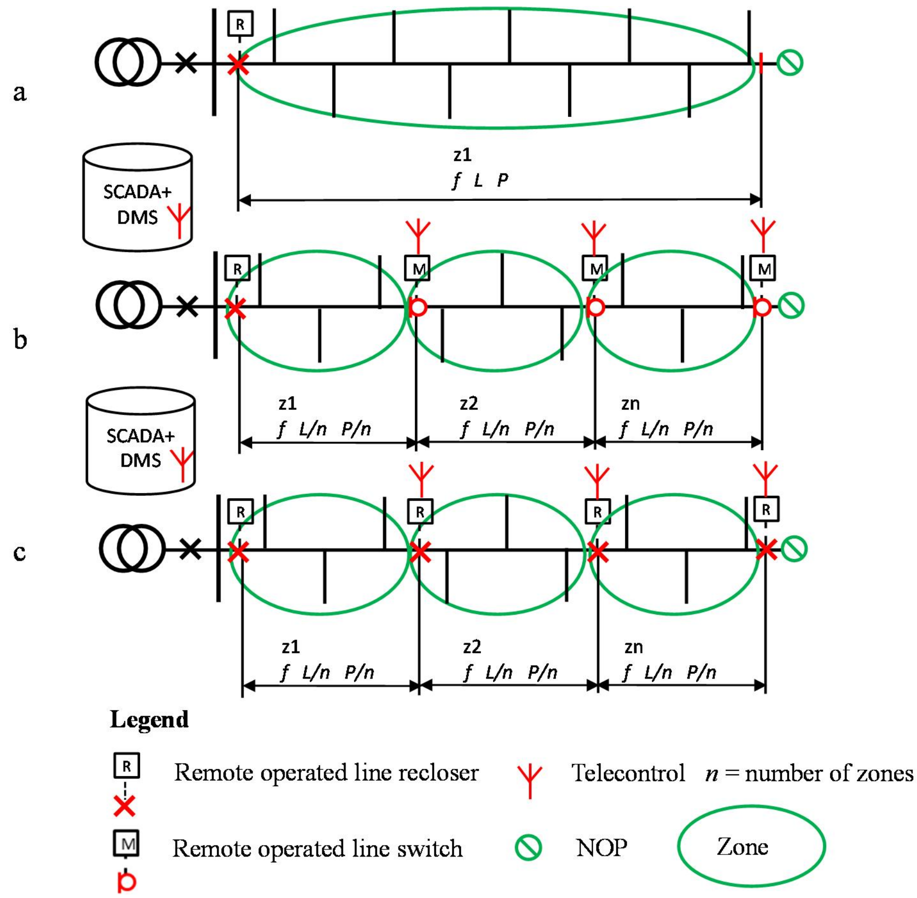


Figure 23. First comparison level with a substation recloser alone (a), second comparison level with a substation recloser and *n* remote operated line switches along the feeder trunk line (b) and the studied feeder with a substation recloser and *n* remote controlled line reclosers along the feeder trunk line (c).

2.4.2 Derivation of the reliability indices

First the equations for the reliability indices of homogenous feeders are derived as a function of the zone number starting from Equations 13–15. The equations are derived by analysing all the pairs of fault/ load sections and combining then equations derived for each pair to a final equation. The complete analysis is presented in Appendixes 1–6. Of the studied zone dividing components the system average interruption frequency index is improved only by the use of reclosers. Using the system average interruption frequency index as expressed in Equation 13 for a feeder protected by a substation recloser alone gives (Appendix 1.1):

$$T-SAIFI = f_l \cdot L + k_d f_d \cdot L, \qquad \textbf{(18)}$$

where

f_l = feeder line fault frequency
k_d = distribution substation density
f_d = distribution substation fault frequency

With two sectionalisation zones, one remote controlled line recloser in the middle of the feeder trunk line and another at the end of the feeder, the corresponding value is (Appendix 2.1):

$$T-SAIFI = 3/4 \cdot f_l \cdot L + 3/4 \cdot k_d f_d \cdot L \qquad \textbf{(19)}$$

With three sectionalisation zones the system average interruption frequency index value is (Appendix 4.1):

$$T-SAIFI = 2/3 \cdot f_l \cdot L + 2/3 \cdot k_d f_d \cdot L \qquad \textbf{(20)}$$

Thus it can be found that with *n* number of sectionalisation zones with remote controlled line reclosers the index value is:

$$T-SAIFI = \frac{(n+1)}{2n}\left(f_l + k_d f_d\right) \cdot L \qquad \textbf{(21)}$$

Also the system momentary average interruption frequency index is influenced by the number of remote controlled line reclosers installed in the feeder. The index value in a feeder protected by a substation recloser only is (Appendix 1.2):

$$T-MAIFI = f_{AR} \cdot frAR \cdot L, \qquad \textbf{(22)}$$

where

f_{AR} = feeder auto-reclosing frequency
$frAR$ = the fraction of successful auto-reclosings

With two sectionalisation zones and remote controlled line reclosers the corresponding value is (Appendix 2.2):

$$T - MAIFI = 3/4 \cdot f_{AR} \cdot frAR \cdot L \,, \tag{23}$$

With three sectionalisation zones and remote controlled line reclosers the system average interruption frequency index is (Appendix 4.2):

$$T - MAIFI = 2/3 \cdot f_{AR} \cdot frAR \cdot L \,, \tag{24}$$

Thus it can be found that with n number of sectionalisation zones and remote controlled line reclosers the index value is:

$$T - MAIFI = [(n+1)/2n] \cdot f_{AR} \cdot frAR \cdot L \tag{25}$$

System average interruption duration index is improved both by remote controlled line switches and reclosers. The value calculated by Equation 15 for a homogenous feeder protected by a substation recloser alone is (Appendix 1.3):

$$\begin{aligned} T - SAIDI = {} & (f_l + k_d f_d) \cdot L \cdot t_s + \\ & 3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r \,, \end{aligned} \tag{26}$$

where

t_s = switching time
t_r = fault repair time

With two zones and two remote controlled line switches, one in the middle of the feeder trunk and another at the end of the feeder, the corresponding value is (Appendix 3):

$$\begin{aligned} T - SAIDI = {} & 1/2 \cdot f_l L \cdot t_s + 1/2 \cdot k_d f_d L \cdot t_s + 1/2 \cdot f_l L \cdot t_c + \\ & 1/2 \cdot k_d f_d L \cdot t_c + 3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r \,, \end{aligned} \tag{27}$$

where

t_c = remote control time

With three zones and three remote controlled line switches the index value is (Appendix 5):

$$\begin{aligned} T - SAIDI = {} & 1/3 \cdot f_l L \cdot t_s + 1/3 \cdot k_d f_d L \cdot t_s + 2/3 \cdot f_l L \cdot t_c + 2/3 \cdot f_l L \cdot t_c + \\ & 3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r \end{aligned} \tag{28}$$

Thus it is found that with *n* number of zones and remote controlled line switches the index value is:

$$T-SAIDI=\frac{1}{n}(f_l+k_d\cdot f_d)\cdot L\cdot t_s+\frac{(n-1)}{n}(f_l+k_d\cdot f_d)\cdot L\cdot t_c+ \\ 3/2\cdot f_d\cdot t_r+1/2\cdot f_l/k_d\cdot t_r \quad \mathbf{(29)}$$

With two sectionalisation zones and remote controlled line reclosers the index value is (Appendix 2.3):

$$T-SAIDI=1/2\cdot f_l L\cdot t_s+1/2\cdot k_d f_d L\cdot t_s+1/4\cdot f_l L\cdot t_c+ \\ 1/4\cdot k_d f_d L\cdot t_c+3/2\cdot f_d\cdot t_r+1/2\cdot f_l/k_d\cdot t_r \quad \mathbf{(30)}$$

With three sectionalisation zones and remote controlled line reclosers the index value is (Appendix 4.1):

$$T-SAIDI=1/3\cdot f_l L\cdot t_s+1/3\cdot k_d f_d L\cdot t_s+1/3\cdot f_l L\cdot t_c+ \\ 1/3\cdot k_d f_d L\cdot t_c+3/2\cdot f_d\cdot t_r+1/2\cdot f_l/k_d\cdot t_r \quad \mathbf{(31)}$$

Thus it is found that with *n* number of sectionalisation zones and remote controlled line reclosers the index value is:

$$T-SAIDI=\frac{1}{n}(f_l+k_d\cdot f_d)\cdot L\cdot t_s+\frac{(n-1)}{2n}(f_l+k_d\cdot f_d)\cdot L\cdot t_c+ \\ 3/2\cdot f_d\cdot t_r+1/2\cdot f_l/k_d\cdot t_r \quad \mathbf{(32)}$$

In Table 2 a summary of the reliability indices derived is given as a function of the number of zones *n* with the zone diving component as parameter.

Table 2. Derived distribution substation level electricity distribution reliability indices when the number of zones is n, the line fault frequency f_l and the distribution substation fault frequency f_d.

Zone dividing component	***T–SAIFI***
Remote controlled line switch	$(f_l + k_d \cdot f_d) \cdot L$
Remote controlled line recloser	$\frac{(n+1)}{2n}(f_l + k_d \cdot f_d) \cdot L$
	T–MAIFI
Remote controlled line switch	$T - MAIFI = f_{AR} \cdot frAR \cdot L$
Remote controlled line recloser	$T - MAIFI = [(n+1)/2n] \cdot f_{AR} \cdot frAR \cdot L$
	T–SAIDI
Remote controlled line switch	$\frac{1}{n}(f_l + k_d \cdot f_d) \cdot L \cdot t_s + \frac{(n-1)}{n}(f_l + k_d \cdot f_d) \cdot L \cdot t_c +$ $3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r$
Remote controlled line recloser	$\frac{1}{n}(f_l + k_d \cdot f_d) \cdot L \cdot t_s + \frac{(n-1)}{2n}(f_l + k_d \cdot f_d) \cdot L \cdot t_c +$ $3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r$

2.4.3 The influence of component type and number of zones on the annual total outage cost

The annual cost of non-delivered energy is calculated by means of the cost of the power and energy not supplied (Lakervi et al.1996: 75):

$$C_{NDE} = \sum_{j=1}^{p} f_i \left[a_j + b_j(t_{ij}) \cdot t_{ij}\right] \cdot P_j, \tag{33}$$

where

p = number of load sections j
f_i = the average outage rate of fault section i
a_j = the per-unit cost value for the power not supplied for the load section j (e.g. €/kW)
$b_j(t_{ij})$ = the per-unit cost value for the energy not supplied for the load section j when the outage time is t_{ij} (e.g. €/kWh)
P_j = the average power of load section j

The equations for different type of zone dividing components and number of zones are derived in a similar way as for the reliability indices by analysing all the pairs of fault/load sections and combining then equations derived for each pair to a final equation. It can thus be found that the annual cost of non-delivered energy in a feeder protected by a substation recloser and equipped with *n* zones divided by remote operated line switches along the feeder is:

$$\begin{aligned} C_{NDE} = {} & \frac{1}{n}(f_l + k_d \cdot f_d) \cdot (a + b \cdot t_s) \cdot L \cdot P + \\ & \frac{(n-1)}{n}(f_l + k_d f_d) \cdot (a + b \cdot t_c) \cdot L \cdot P + \\ & 3/2 \cdot f_d (a + b \cdot t_r) \cdot P + 1/2 \cdot f_l / k_d (a + b \cdot t_r) \cdot P \end{aligned} \quad \textbf{(34)}$$

With *n* sectionalising zones divided by remote controlled line reclosers the annual cost of non-delivered energy is:

$$\begin{aligned} C_{NDE} = {} & \frac{1}{n}(f_l + k_d \cdot f_d) \cdot (a + b \cdot t_s) \cdot L \cdot P + \\ & \frac{(n-1)}{2n}(f_l + k_d f_d) \cdot (a + b \cdot t_c) \cdot L \cdot P + \\ & 3/2 \cdot f_d (a + b \cdot t_r) \cdot P + 1/2 \cdot f_l / k_d (a + b \cdot t_r) \cdot P \end{aligned} \quad \textbf{(35)}$$

The annual cost of auto-reclosing comprises of the annual cost of high-speed and delayed auto-reclosing. The annual cost of high-speed and delayed auto-reclosing of a sectionalisation zone is calculated by multiplying the average power and the line auto-reclosing frequency with the auto-reclosing unit cost. The annual cost of auto-reclosing for the whole feeder is calculated by summing the cost of all the sectionalisation zones. Thus the annual cost of auto-reclosing is (Figure 23 c on page 47):

$$C_{AR} = C_{HSAR} + C_{DAR} \quad \textbf{(36)}$$

$$= \sum_{i=1}^{p} \left(\left(f_{HSARi} \cdot c_{HSAR} + f_{DARi} \cdot c_{DAR} \right) \cdot P_i \right), \quad \textbf{(37)}$$

where

p = number of sectionalising zones i
f_{HSARi} = HSAR frequency in sectionalising zone i
c_{HSAR} = HSAR unit price
f_{DARi} = DAR frequency in sectionalising zone i
c_{DAR} = DAR unit price
P_i = the average power of sectionalising zone i

The annual cost of auto-reclosing in a homogenous substation recloser protected feeder equipped with three identical zones divided by remote controlled line reclosers is (Appendix 6):

$$C_{AR} = 2/3 \cdot \left(f_{HSAR} \cdot L \cdot P \cdot c_{HSAR} + f_{DAR} \cdot L \cdot P \cdot c_{DAR} \right) \quad \textbf{(38)}$$

It can thus be shown that the equation for the annual cost of auto-reclosing of overhead line rural network feeders can be expressed as a function of the number of sectionalisation zones *n:*

$$C_{AR} = [(n+1)/2n] \cdot \left(f_{HSAR} \cdot c_{HSAR} + f_{DAR} \cdot c_{DAR} \right) \cdot L \cdot P \quad \textbf{(39)}$$

The annual total outage cost is thus the sum of the annual cost of non-delivered energy and auto-reclosing:

$$C_{INT} = C_{NDE} + C_{AR} \quad \textbf{(40)}$$

In Table 3 a summary of the annual cost of non-delivered energy and auto-reclosing is given as a function of the number of zones n with the zone diving component as parameter.

Table 3. Derived equations of the cost of NDE and AR when the number of zones is n, the line fault frequency f_l and the distribution substation fault frequency f_d.

Component	**The annual cost of non-delivered energy C_{NDE}**
Remote controlled line switches	$\frac{1}{n}(f_l + k_d \cdot f_d) \cdot (a + b \cdot t_s) \cdot L \cdot P +$ $\frac{(n-1)}{n}(f_l + k_d f_d) \cdot (a + b \cdot t_c) \cdot L \cdot P +$ $3/2 \cdot f_d (a + b \cdot t_r) \cdot P + 1/2 \cdot f_l / k_d (a + b \cdot t_r) \cdot P$
Remote controlled line reclosers	$\frac{1}{n}(f_l + k_d \cdot f_d) \cdot (a + b \cdot t_s) \cdot L \cdot P +$ $\frac{(n-1)}{2n}(f_l + k_d f_d) \cdot (a + b \cdot t_c) \cdot L \cdot P +$ $3/2 \cdot f_d (a + b \cdot t_r) \cdot P + 1/2 \cdot f_l / k_d (a + b \cdot t_r) \cdot P$
	The annual cost of auto-reclosing C_{AR}
Remote controlled line reclosers	$C_{AR} = [(n+1)/2n] \cdot \left(f_{HSAR} \cdot c_{HSAR} + f_{DAR} \cdot c_{DAR} \right) \cdot L \cdot P$

2.4.4 Calculation examples

Figure 24 shows the impact of the number of zones and remote controlled line reclosers and comparison level on the payback time and total outage cost reduction capability of remote controlled line reclosers in a homogenous overhead line feeder with an average power of 1 MW with feeder line total length as parameter. Depending on the feeder length several remote controlled line reclosers may be cost-effective in new substation recloser protected feeders with no present remote controlled line switches. This is the case also in existing feeders with two remote operated line switch groups although the total outage cost reduction capability is lower. Changing the remote controlled line switches between the substation recloser and normally open point to reclosers in existing feeders is not as cost-effective as in the two before mentioned cases.

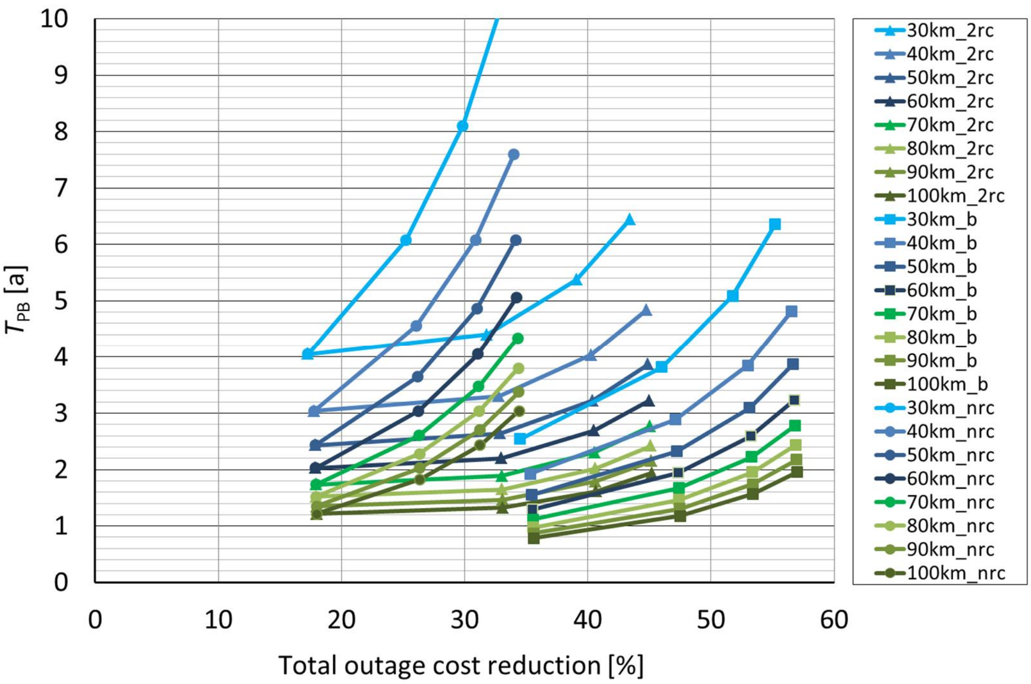


Figure 24. The impact of the number of sectionalising zones and comparison level on the payback time and total outage cost reduction capability of remote controlled trunk line reclosers in a homogenous substation recloser protected OHL feeder with an average power of one MW and the feeder line length as parameter. The number of zones n is from left to right two to five. The comparison level is expressed in the legend after the total length of the feeder. b = no FA, 2rc = two remote controlled line switches and nrc = *n* number of remote controlled line switches. Used parameter values are presented in Appendix 7.

Equations for the substation level electricity distribution reliability indices and the annual total outage cost have been derived for a homogenous rural network feeder as a function of the component type and number of zones. Line reclosers improve substation level feeder average reliability indices by restricting the influenced area of faults to the nearest upstream recloser and shorten restoration time of healthy feeder parts. Using the derived expressions the effect of component type and number of zones on the total outage cost and reliability indices is presented in Figure 25, where 100 % corresponds to a feeder with a substation recloser alone. Considering the average number of remote controlled line switch groups of medium and long feeders to be two, *T–SAIDI* of the Finnish rural networks has been improved by almost 40 % by the use of remote controlled line switch groups. The annual total outage cost has been reduced by about 22 % by using remote controlled line switches (green arrow). By using remote controlled line reclosers the cost could be reduced by another 14 % (blue arrow) and doubling the number of line reclosers from two to four another 18 % (red arrow).

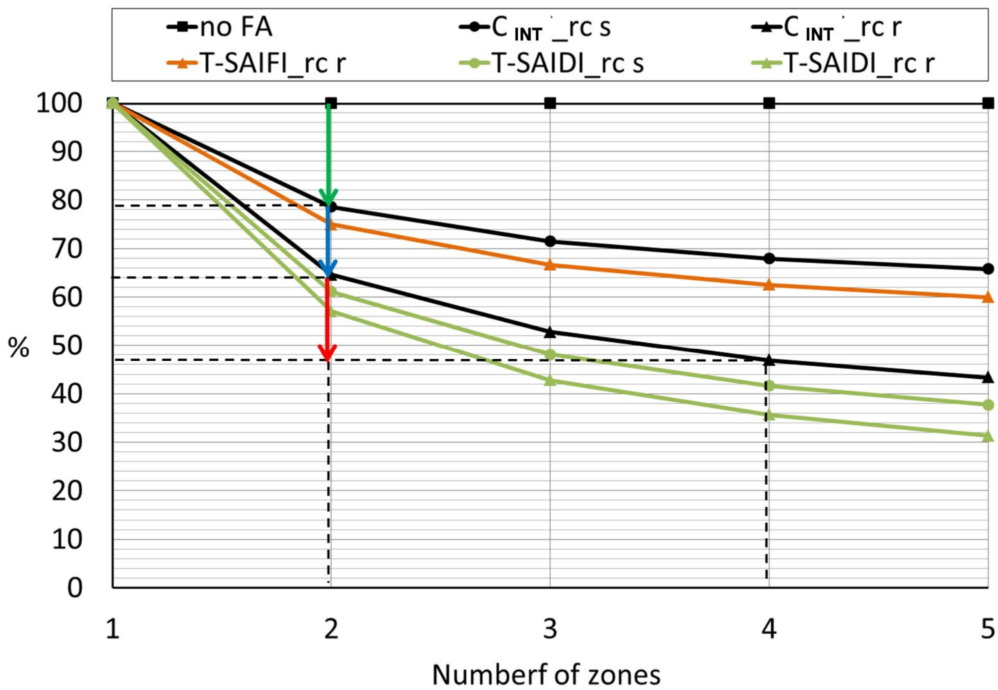


Figure 25. The impact of the component type and number of zones on the percentage annual total outage cost and *T–SAIFI* and *T–SAIDI* of a homogenous feeder. The comparison level is a feeder with only manually operated line switches.

2.5 Summary

In this chapter equations for the reliability and economical indices have been derived as a function of the number of zones. For comparison also equations for feeders with remote controlled line switches are derived. It has been found that *T–SAIDI* and the annual cost of non-delivered energy are composed of four components, which are functions of the number of zones, the switching time, the remote control time and the repair times and the feeder configuration. The derived equations can be utilized in estimating the reliability and economical indices of mainly homogenous networks but also for inhomogeneous networks to make an estimation if a case study is necessary. Using these equations and national electricity distribution statistic data, the influence of feeder line length, feeder automation and number of zones on the annual total outage cost and electricity distribution reliability indices in homogenous rural network feeders has also been demonstrated. Since energy weighted *T–SAIDI* has been the main factor for benchmarking reliability, remote control of rural overhead network line switches has been the most effective means of improving electricity distribution reliability in Finland. The second regulation period has introduced a wider perspective on electricity distribution quality when also short interruptions are included into the cost of poor quality. To see the influence of distribution system irregularity and the incentives of the second regulatory period on the cost efficiency of different alternative investment strategies, a generic electricity medium voltage distribution system based on national annual outage statistics is designed in the next chapter. The calculation of the electricity distribution reliability and economical indices is based on the method derived in this chapter. The efficiency of different reliability improving investment strategies will then be analysed with the help of this generic distribution system.

3 DESIGN OF THE GENERIC ELECTRICITY DISTRIBUTION SYSTEM

It has been found that electricity distribution reliability is influenced by system load density, voltage level, system neutral grounding, underground cabling level, network redundancy, circuit configuration and the automation level. In Chapter 2.4 the influence of feeder automation, feeder average power and feeder length on the payback time of feeder automation in rural electricity distribution systems was presented. In this chapter, models of average Finnish sub-urban distribution systems are designed. To cover not only feeders used at present but also possible new alternative feeder systems, different feeder types and feeder automation schemes are designed and combined in the modelling and calculation. Thus the influence of feeder type and feeder automation scheme on the reliability and cost indices of different investment strategies can be presented.

To begin with, the behaviour of the electricity distribution system is studied by looking at the present Finnish distribution system. By analysing statistics from the Finnish distribution system indices, such as load density, average feeder length and number and density of distribution substations for rural and sub-urban areas are calculated. With the help of these average indices the primary distribution substation and feeder systems are modelled. The feeder configurations are designed according to the results of an international questionnaire (Lågland 2004: Appendix 3–6). The distribution system components are chosen to fulfil the technical constraints of the distribution system such as loads, currents, voltages and short-circuit levels. Contingency support is achieved by adding normally open switches to points on the feeders which are located near neighbouring feeders of the same and the neighbouring primary distribution substation. Only single contingencies (N–1) are considered in this study.

Distribution reliability calculations are based on single line diagrams of the generic feeders. Excel spread sheets are used for calculations with common input data on the input spread sheet. The input data are: list of components, unit prices, fault frequencies, component electrical data, interruption data, outage unit costs, loading levels and switching and repair times. Every generic feeder studied is presented on its own spread sheet. The calculations are summarised on summary spread sheets and important results are presented as charts.

3.1 The Finnish medium-voltage distribution system

The area of Finland, seas excluded, is 338424 km² of which 34 525 km² is water and 303 899 km² land (National Land Service of Finland 2009). Over 70 % of the land area is forest (Ministry of Agriculture and Forestry 2009). The number of distribution companies has decreased from 112 in 1997 to 90 in 2009. Until 2004 the rural distribution companies where classified according to the region where they were sited, Coastal Finland in the south and west, Central Finland and Lapland in the north. Urban distribution companies were defined as utilities where the share of underground cables was 10 % or more of the utility total line length. Originally the urban distribution voltage was 6 kV and 10 kV, but nowadays 20 kV is by far the most common medium voltage used.

In addition to 111000 km of overhead lines and 14000 km of underground cable lines over 8000 km of coated overhead conductor (COC) has been installed, because it allows tree-contact for a restricted time. Since 2005 the medium-voltage distribution systems are divided into three categories according to the share of underground cabling: rural (0–30 %), urban (30–75 %) and city (75–100 %) distribution systems (Table 4).

Table 4. Electricity distribution MV system neutral and line data of the Finnish distribution companies in 2008 (FEI 2009: 1).

1–45 kV network	**Lines** [km]				**System neutral** [km]		
	Rural 0–30 %	Urban 30–75 %	City 75–100 %	All	Iso-lated	Partly comp.	Comp.
OHL	104849	5441	691	110980	57145	1802	51347
COC	7294	884	133	8312	3819	60	4342
OHC	270	188	67	524	260	2	252
UGC	3127	3403	7492	14023	8066	162	5442
All	115540	9915	8383	133838	69289	2026	61382
	Lines [%]				**System neutral** [%]		
AR protected	76.8	37.6	25.9	70.7	75.4	83.5	67.0
UGC level	2.7	34.3	89.4	10.5	11.6	8.0	8.9
OHL in forest	49	16	29				

Since the 2003 interruption statistics was more detailed regarding the primary distribution substation service area, it is utilized to calculate average detailed network indices. The average primary distribution substation supply area is 404 km² including both urban and rural distribution companies. The average number of feeders per primary distribution substation is 10.8 for urban and 6.3 for rural distribution companies, while the average feeder length is 7.0 for urban and 31.6 for rural distribution companies. In urban distribution companies the average number of distribution substations per feeder is 9.4 and in rural distribution companies 28.7. The medium number of distribution substations per km feeder length is 1.3 in urban and 0.9 in rural distribution systems (Table 5).

Table 5. Electricity distribution MV system data of Finnish distribution companies in 2003 (FEI 2004: 3).

Rural utilities	Coastal regions	Central Finland	Lap-land	Rural total	Urban total	Finland total
Network (5–20 kV)						
Total line length [km]	36185	62169	11358	109713	15248	124961
Overhead lines [km]	33629	60547	11156	105331	7878	113209
Underground cables [km]	2557	1623	202	4382	7370	11752
HSAR and DAR protected [km]	17256	61857	11340	89940	90453	101410
Distribution substations						
Number	36442	54648	8453	99543	20384	119927
Number/feeder	26.8	29.6	31.9	28.7	9.4	21.2
Number/km	1.0	0.9	0.7	0.9	1.3	1.0
Other data						
Primary distribution SS	229	263	59	551	202	753
Number of feeders	1358	1848	265	3471	2175	5646
OHL in forests [%]	28	49	60	43	43	43
Urban utilities	Percentage underground [%]				Voltage [kV]	
	10–25	25–50	50–75	Over 75	5…10	20
Network (5–20 kV)						
Total line length [km]	4015	5454	3681	2098	2083	13165
Overhead lines [km]	3247	3200	1302	129	437	7441
Underground cables [km]	768	2254	2379	1969	1646	5724
HSAR and DAR protected [km]	3608	4821	2352	176	544	10413
Distribution substations						
Number	4343	7399	5324	3318	3425	16959
Number/feeder	16.3	13.4	7.6	5.1	5.4	11.0
Number/km	1.1	1.4	1.4	1.6	1.6	1.3
Other data						
Primary distribution SS	36	62	67	37	48	154
Number of feeders	266	551	701	657	629	1546
OHL in forests [%]	52	35	33	11	26	43

3.2 Primary distribution substation service area design

In Finland 24 kV medium voltage overhead and cable line feeders feed the distribution substations where the voltage is transformed to consumer level normally 400/230 V AC.

> A *feeder* is all the downstream circuitry fed by a specific feed point at the substation, and the feeder's configuration at any moment is defined by the open points which terminate its electrical pathways. The route, service area, and load for any particular feeder can be changed by simply opening and closing several tie switches, or even more extreme changes rendered by constructing a few short new segments and adding open points so as to alter the feeder's boundaries quite significantly (Willis 2004: 14).

The most common network configuration in urban areas is open ring and in rural areas radial. To be able to have a competitive transmission price level rural distribution companies often have also urban areas within their service territories (Hyvärinen 2008: 75). In that case it is natural to also separate the feeders with underground open ring feeders for the urban area and overhead radial feeders for the rural area (Figure 26 a–c).

Combining the details regarding feeder configuration and primary distribution service area a 110 kV high-voltage network structure as in Figure 26 b can be derived for the sub-urban area distribution where the primary distribution substation density is two times the economical load reach of the feeder trunks (20 km) and the distance between the 110 kV lines is about 15 km. Thus the primary distribution substation service area is 300 km^2.

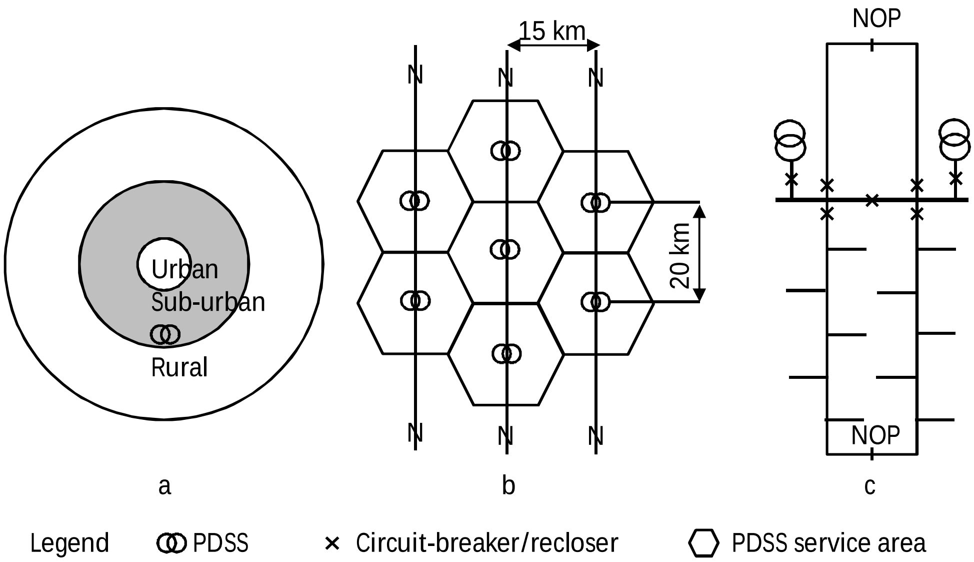


Figure 26. Rural/sub-urban primary distribution substation location (a), arrangement of the high voltage (HV) distribution network (b) and MV feeder arrangement alternatives (c). Separation of urban and sub-urban feeders is preferred.

3.3 Medium-voltage feeder design

The average size of distribution substations in rural areas is 100 kVA, in sub-urban areas 315 kVA and in urban areas 500 kVA. The average loading of distribution transformers in Finland was 65 % in the 1990´s (Unipede 1995: 1). The average underground cabling of rural networks was 2.7 % and urban networks 34.3 % in 2008 (FEI 2009:1). The aim of the generic feeder system design is to model the future Finnish sub-urban feeder alternatives on a common level. Near-future main alternatives are:

- Increasing underground cabling and use of coated overhead conductors
- Increasing use of the 1000 V system
- Increasing use of the satellite distribution system

Selective underground cabling, where the main targets will be the feeder trunk and forest paths, will continue. To optimise distribution reliability it is more beneficial to have the more reliable underground cable line in the beginning of the feeder. Thus one alternative is to underground cable the first part of the generic feeder. Increasing use of coated overhead conductor lines improve distribution reliability when the line can withstand tree contact for some time without any outage. Locating the line to the roadside also speeds up fault location. When changing existing overhead lines partly or completely to underground cable lines a possible solution is to use the satellite distribution system.

With a lower loading level of 0.4 the average power of the feeder is 1.61 MW which requires a primary distribution transformer size of 16 MVA with six outgoing feeders (Table 6). In the different generic distribution systems, all the feeders connected to the primary distribution transformer are of the same type. Comparison of different distribution systems is made between the primary distribution substation distribution areas with regard to the different generic feeder types, which are presented in the next chapter.

Table 6. Generic distribution area design. Variables: k_d = distribution substation density, *LL* = loading level.

Feeder part	**Line length** [km]	**Distribution substations**			**Feeder**	
		k_d [1/km]	Number	*S* [kVA]	*LL*	*P* [MW]
First	8.6	0.93	8	315	0.4	1.01
Second	17.1	0.877	15	100	0.4	0.60
Total	25.7	0.895	23	4020	0.4	1.61

3.4 Detailed generic feeder design

3.4.1 Sub-urban/rural generic model feeders

The fundamental elements of the distribution systems are voltage level, system neutral grounding, line type and configuration, protection system and feeder automation scheme. Finnish common sub-urban/rural distribution voltage levels are 20 kV, 1 kV, 0.4 kV. Line types to be used are overhead, underground cable and overhead cable lines. Protection system feeder line components are, protection relays, measurement transformers, circuit-breakers, line reclosers and fuses. The utilisation of the advantages of the different components is done in locations of the feeder lines where the benefits are maximized. The optimal location of components is further determined by the location of normally open points and used sectionalisation scheme.

The aim of designing the generic model feeders is:

- to identify cost-effective distribution system alternatives with higher electricity distribution reliability than the overhead line distribution system
- to compare the economical and electricity distribution reliability indices of the designed solutions using different substation automation and feeder automation schemes

Because the properties of the generic model feeders are compared to each other the configuration, i.e. routing and switch locations, of the generic feeders are, as far as possible, made similar. All the designed feeders are radial feeders with normally open points at the end and halfway downstream of the feeder. The reference feeder or the feeder to which all the other generic model feeders will be compared is the overhead line generic feeder, which is the main feeder type used in Finnish rural networks. To demonstrate the influence of underground cabling on the indices a mixed generic feeder is designed (Table 7, mixed 1). When the first half of the feeder is underground cabled also the configuration of the first part of the feeder is changed to open ring to compensate for the long fault location and repair time of the underground cable part. In the second alternative generic feeder (mixed 2) the electricity distribution reliability is further improved by underground cabling also the trunk of the rest of the feeder. In Finland coated overhead conductor lines are used because the operation of the line can continue for some time during earth-fault conditions. Thus the fourth alternative generic feeder is a coated overhead conductor feeder with the same configuration as the basic overhead line feeder. The configuration and distribution transformer size of a satellite distribution system can be similar to a rural overhead line distribution system and is thus an alternative to underground cable rural distribution systems without having to change the routing of the network. In the sixth alternative the qualities of the coated overhead conductor are utilised together with the benefits of the 1000 V system in the lateral lines of the generic model feeder.

Table 7. Defined generic model feeders and protection schemes.

Generic distribution system	**ID**	**Protection scheme**		
		Substation	Lateral lines	Distribution substation transformer
Overhead line	ohl	Recloser		
Mixed 1	ugc_ohl			MV fuses in UGC lines
Mixed 2	ugcT_ohl			
Coated overhead conductor	coc			
Underground cable satellite	ugc_sat	Circuit-breaker	MV fuses	MV fuses
Overhead cable	ohc_1kV	Recloser	Circuit-breakers	

The protection schemes include feeder protection needed to protect the components of the feeder from thermal and dynamic damage in different fault situations. In the next chapter feeder automation schemes are introduced which also use protection elements, e.g. line reclosing, not for protection purposes but to improve the electricity distribution reliability of the feeders. Typical protection component locations in Finnish sub-urban/rural distribution systems are substation reclosers/circuit-breakers and fuses to protect distribution transformers (Table 7). From the beginning of this century also line reclosers and circuit-breakers in the 1000 V distribution system have become a standard element in the Finnish distribution system. The satellite distribution system is not widely used in Finland yet but here it is presented as an alternative in underground cabling of Finnish sub-urban/rural distribution systems.

3.4.2 Feeder main data and configuration

Main data of the different generic model feeders are presented in Table 8. The total length of the feeders is 25.7 km and 26.4 km for the mixed (UGC/OHL) feeders while the average length of Finnish rural feeders was 31.6 km in 2003 (EMA 2004). The width of the network also influences the electricity distribution reliability. Typically the total length of the laterals is about equal to the total length of the trunk line in rural network feeders. Because the distribution substation density and size should correspond to the average sub-urban/rural values also the power density should correspond to typical Finnish values. Actually most of the values of the characteristics given in Table 8 vary in a large scale and it is therefore difficult to choose any value to represent Finnish distribution systems. Some parameter average values of different Finnish regions are presented in Table 9. For comparison also the values of the same parameters of sub-urban feeders in the distribution system of Vaasan Sähköverkko Oy, and rural feeders in the Somero region of Fortum Sähköverkko Oy distribution company are presented. In Figures 27–28 the configuration of the generic model feeders is presented.

In the previous six different generic model feeders have been designed. The feeders differ regarding line type, underground cabling degree, voltage level, and protection scheme. In the next chapter a checking of the electrical constraints of the generic hybrid feeder models is made.

Table 8. Parameter values of the different generic model feeders.

Parameter	**First part**	**Second part**	**Total**
	/mixed feeder value		
Feeder trunk line length [km]	5.4/9.3	5	10.4/14.3
Feeder line total length [km]	8.6/9.3	17.1	25.7/26.4
Feeder width	0.59/0.0	2.42	1.47/0.85
Feeder power [MW]	1.0	0.6	1.6
Number of distribution substations	8	15	23
Distribution substation density [1/km]	0.93/0.86	0.88	0.89/0.87
Size of distribution substations [kVA]	315	100	
Length of lateral lines [km]	0.8	1.1–2.2	0.8–2.2

Table 9. Parameter values of Finnish rural distribution systems (EMA 2007–2010, 2004).

Parameter average value	**Finish average/region**				**Company**	
	Coast	Central	Lapp-land	Rural	VSV Oy [1]	FSS Oy [2]
Feeder:						
– line total length [km]	26.6	33.6	42.9	31.6	28.3	56.7
– power [MW]					0.88	0.82
Distribution substation:						
– density [1/km]	1.0	0.9	0.7 1	0.9	0.88	0.81
– average power [kW]				21.1	35	17.8

[1] Vaasan Sähköverkko Oy (Lågland & Kauhaniemi 2008, Nykänen 2009)

[2] Fortum Sähkönsiirto Oy (Voutilainen 2007)

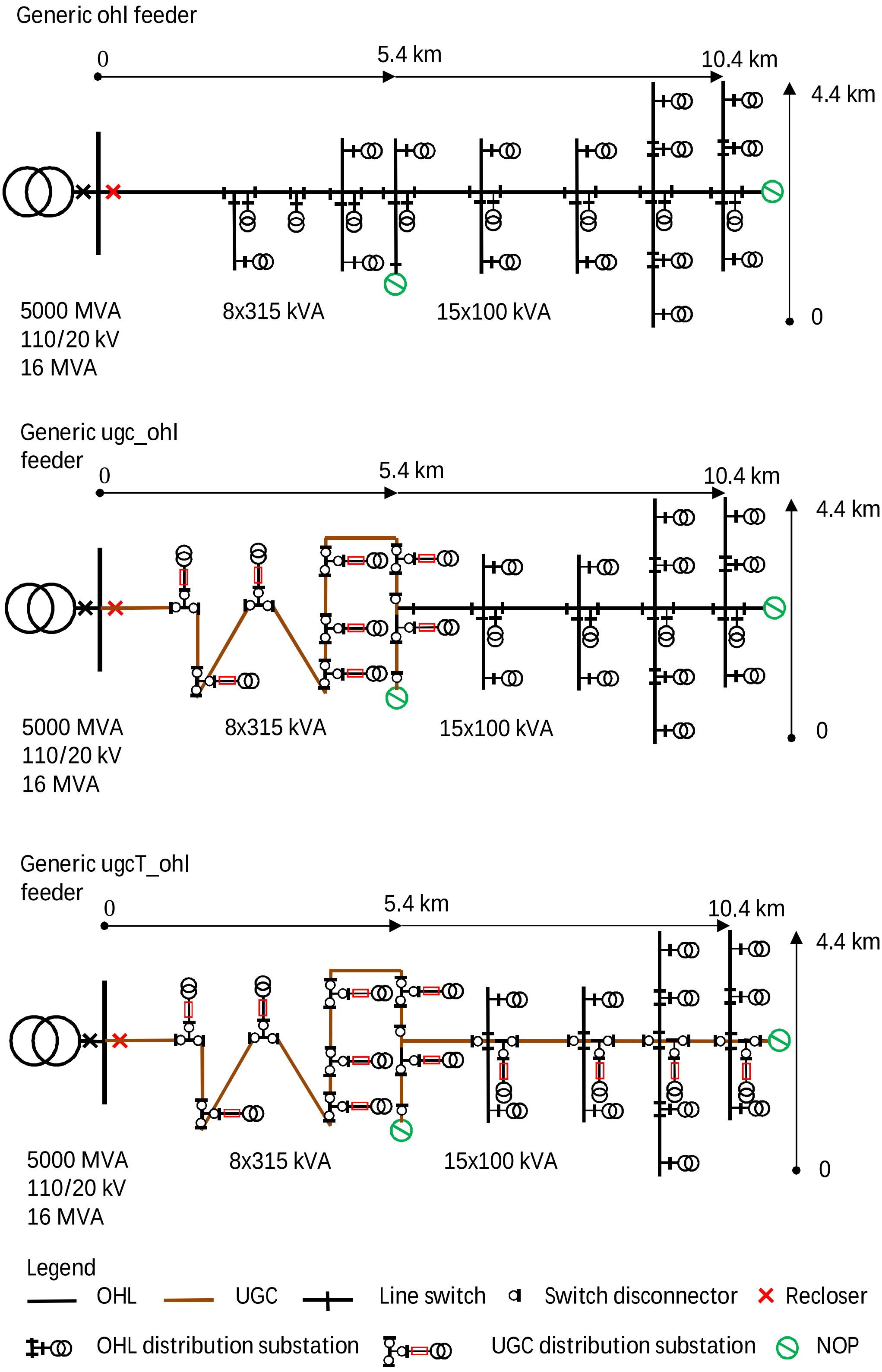


Figure 27. Configuration of the overhead line and mixed feeders.

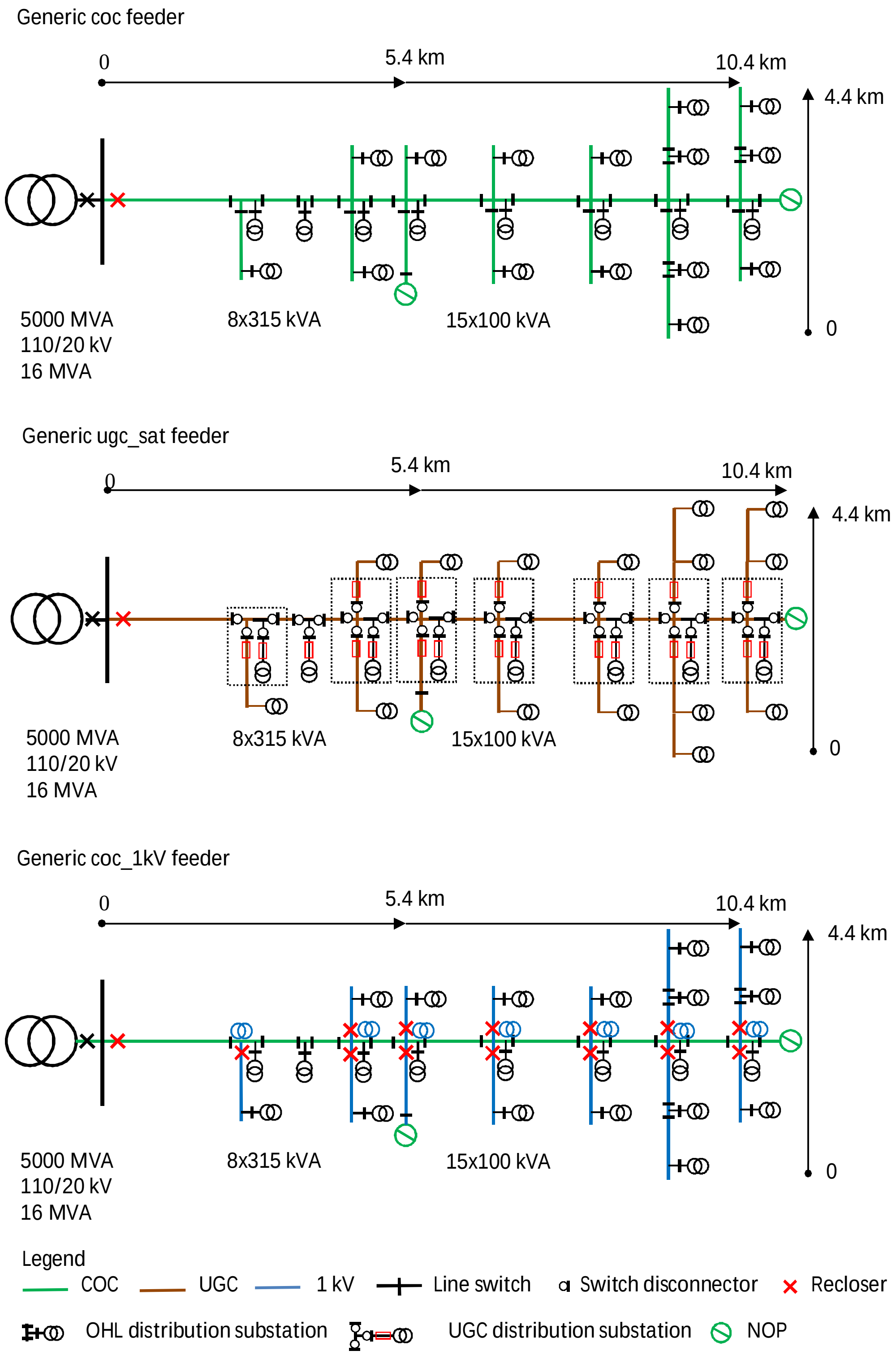


Figure 28. Configuration of the coated overhead conductor feeder, the UGC satellite feeder and the coated overhead conductor feeder trunk line/1000 V system lateral lines feeder.

3.5 Checking of the electrical constraints of the generic hybrid feeder models

The dimensioning of the lines is done by selecting the lines of the feeders according to their economic area. The voltage drops of the different feeders are then calculated for the worst case of all the different feeders. The short-circuit currents for the different feeder line locations are calculated and the short-circuit strength of the lines is checked. Finally, the criteria for over current (O/C) protection are checked.

3.5.1 Line dimensioning

The lines are dimensioned according to their economical loading allowing a 2 % annual load growth when the distribution substations are loaded to 100 % of their rated load. The normal loading level is 40 %, so there is a 150 % safety margin which covers also the higher loading level in contingency situations where a higher loading level is permitted. In Appendix 8 the electrical, thermal and economical properties for some lines used in Finland are presented.

3.5.2 Voltage

The cumulative voltage drops along the feeders are calculated and presented in Figure 29. For Finnish medium voltage networks the maximum allowed voltage drop for rural areas is 5 % and for urban areas 3 %. According to the results the voltage drop of all the feeders, except for the coc_1kV feeder, are well under the limit for urban areas. Even though a double coated overhead cable is used in the coc_1kV feeder lateral lines the voltage drop exceeds the limit for urban feeders although it falls below the limit for rural feeders. The voltage drop is calculated using equation (Lakervi et al. 1996: 39):

$$U_h = \sqrt{3}\left(I_p R + I_q X\right), \tag{41}$$

where

I_p = the resistive component of the load current
I_q = the reactive component of the load current
R = the resistance of line
X = the reactance of line

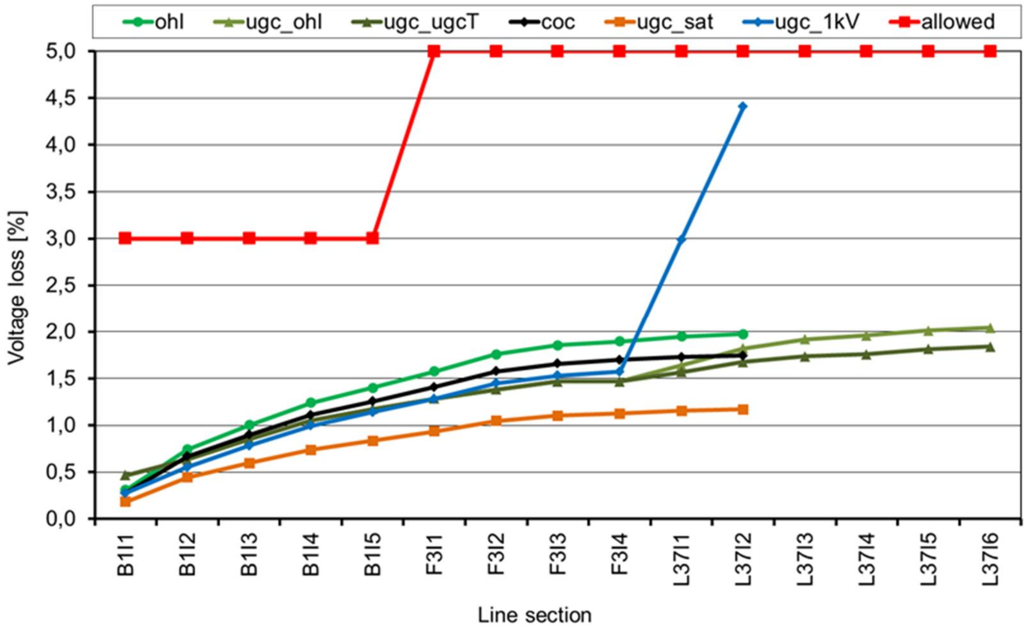


Figure 29. The maximum percentage cumulative voltage drop along the different generic feeders with a 100 % distribution substation load which corresponds to a loading of 2.5 times the average feeder load.

3.5.3 *Short-circuit strength*

In Appendix 9.1 the fault levels in the different parts of each model feeder are calculated when the short-circuit level of the primary side of the feeding network is 5000 MVA (Lågland 2004: Appendix 16). The results are summarised in Appendix 9.2 where the two-phase short-circuit currents and 150 % load currents are calculated and the constraints for protection checked. For proper short-circuit protection the two-phase short-circuit current should be larger than 1.5 times the load current at the beginning of the feeder. The feeder short-circuit strengths are valid for 1 second while the protection setting times are shorter, so that there is a reasonable safety margin.

3.5.4 *Contingency of supply*

Increasingly since 1980s, utilities have pushed equipment utilization upwards with a few per cent per decade. In urban areas the increase has been most significant. Also the maximum planned peak load under contingency conditions has increased by about 10 per cent in 30 years in USA (Willis 2004: 830). In Finland the maximum loading occurs during the winter and in summertime the loading may be quite low although the use of air conditioning is increasing and the loadings in hot summer days may be quite high. The maximum loading levels of the primary distribution transformers in Finnish distribution companies show considerable variation. What are then the consequences of higher utilization rates?

> If utilization ratio is pushed too high, problems are likely to develop. High utilization rates are not a cause of poor reliability. Properly designed power systems can tolerate high loading levels well. However N – X methods cannot always recognize the weaknesses in all power systems. When equipment utilization ratio is raised too much, an N – 1 compliant system which previously gave good service, may no longer give satisfactory reliability of service, even if it continues to meet the N – 1 criterion. It is desirable for the distribution company to increase loading levels because it seeks to make the utility financially efficient, which is potentially beneficial also for the customers. A power system that operates at 83% or 90 % or even 100% utilization of equipment at peak can be designed to operate reliably, but something beyond N–1 methodology is required to assure that it will provide good customer service reliability. (Willis 2004: 828)

Here the N–1 criterion is used to calculate the highest possible load level of the primary distribution transformers. If all the loads are to be fed during an N–1 contingency then:

$$LL \cdot N = (N-1) \cdot ELL\,, \tag{42}$$

where

LL = loading level of the primary distribution transformers
ELL = emergency loading level of the primary distribution transformers
N = number of primary distribution transformers connected to a feeder

Table 10 gives the different calculated maximum possible loading levels of the supplying primary distribution transformers feeding the different generic model feeders. The designed generic feeders can connect to maximum three primary distribution substations which mean that with an emerging loading level of 1.2 the loading level of the primary distribution transformers can be 0.8. Thus systems with higher utilisation rates have larger contingency support neighbourhoods. Although the N–1 criteria dos not solve the reliability of the distribution system it is still a useful criterion to use when deciding what feeder configuration to use.

Feeder strength is by Willis defined as the ability to transfer at least some load between substations during outages through the feeder system (Willis 2004: 505).

Table 10. Calculated maximum possible loading levels of the supplying primary distribution transformers of the different generic model feeders with different emergency loading levels.

Number of primary distribution transformers ***N***	**Emergency loading level** ***ELL***		
	1.00	1.20	1.30
2	0.50	0.60	0.65
3	0.67	0.80	0.87
4	0.75	0.90	0.97

3.6 Feeder automation schemes used for improving electricity distribution reliability

Automation schemes used in the different feeder models influence the electricity distribution reliability, annual total outage and total cost of the generic feeders as well as the payback time of different reliability improving investments. Electricity distribution continuity can be improved even after a fault has occurred by eliminating a transient fault or limiting the influence and duration of a permanent fault by using distribution automation. Automatic loop sectionalising, automatic switching of supply and remote control of line switches and reclosers are such automation possibilities. Technology limitations and high costs compared to the benefits have restricted the use of automation in improving the electricity distribution reliability of rural and sub-urban areas. Technological progress, privatization, quality awareness and a greater dependence on continuous electricity distribution have created pressures for improving electricity distribution quality also in rural and sub-urban areas as well. Feeder automation implementations studied in this work will be fault indication, remote control of line switches and reclosers. The following chapters describe the designing of the different feeder automation schemes studied in this work by implementing them on the different generic model feeders.

3.6.1 Fault location and remote control

Fault information processing is performed after data acquisition from intelligent electronic devices, fault indicators and automatic meter reading equipment (Figure 30). Fault isolation and supply restoration is performed in a two-staged restoration process. In the first stage remote controlled line switches and reclosers are used to restore supply to the healthy parts of the feeder. In the second stage manual switching to isolate the fault in the faulty zone is performed by crew at a later stage. Depending on the location of the fault and possible backup connections supply can now be restored to additional customers.

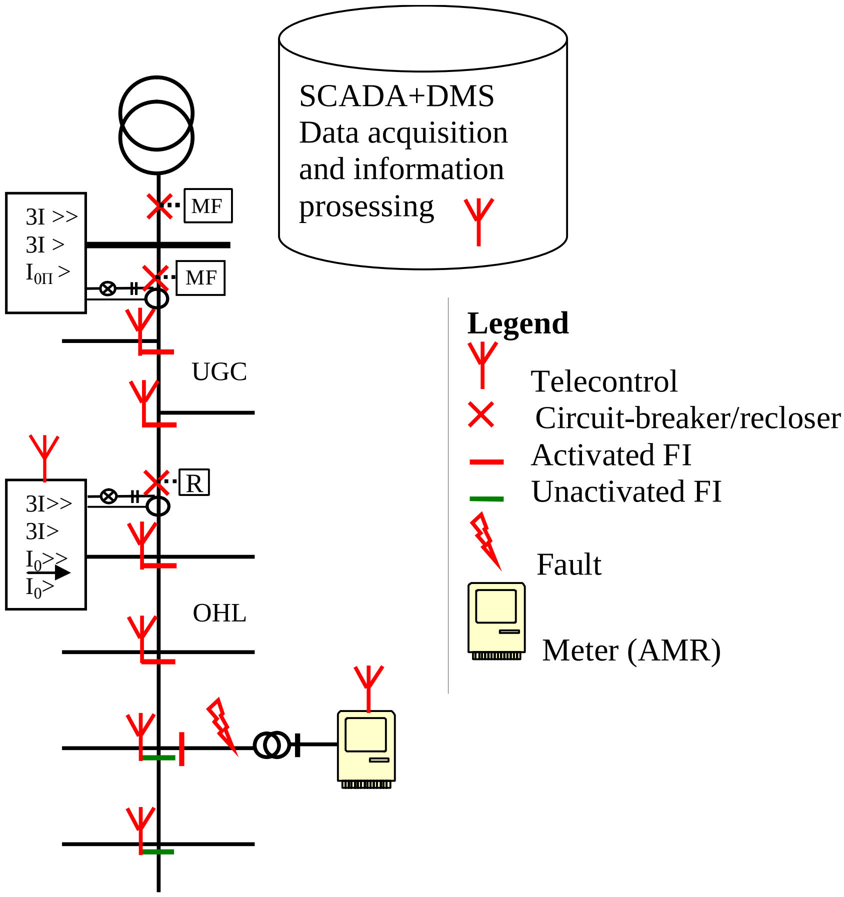


Figure 30. Fault management of Finnish MV distribution feeders.

Fault location can be made by protection relays, trial switching, fault detection and automatic meter reading or as a result of customer calls. Short-circuit location methods in Finnish rural/sub-urban networks are based upon trial switching, fault indication and numeric relay measurement. In trial switching the short circuit faults in power distribution lines were located by dividing the line into sections and trying to close the energizing circuit breaker which was both time consuming and also exposed additional stresses on the equipment. With locally/remote read/set fault indicators the faulty part of the distribution system can faster be identified and isolated (Falaghi et al. 2005). By combining trial switching and fault indication the number of fault indicators can be reduced. The processing and communication capacity of numerical relays is utilized for fault location purposes also. In Finland the most common practice was to register the fault current magnitude solely. This value is then compared to the computed current values in different feeder locations, and candidate places for fault location are obtained. A novel technique has been developed, which is based on the measurement of busbar voltages and feeding primary transformer currents only. The key of the technique is the compensation of the load current superposed on the fault current. The accuracy is thus even better than with the previous methods. This technique is suitable also for retrofit applications because only one measuring relay per primary transformer is needed (Vähämäki et al. 2005).

Earth-fault location function based upon reactance measurement is implemented in numeric relays for neutral isolated distribution systems and is being tested for earth-fault compensated distribution systems. Because the implementations of fault location are closely connected to the utilisation of remote control, the effects of fault location and remote control are studied together by comparing the influence of different schemes on the electricity distribution reliability indices and cost (Table 11).

In Figure 31 the feeder configuration with the different feeder automation schemes are presented. In the first scheme (fi) locally read and set fault indicators are added to every second distribution substation of the feeder trunk line. In the second scheme (rfi) the fault indicators are remote read and set and switching is performed manually. In the third scheme the fault is first located to the first or second feeder half by remote trial switching after which the exact location of the fault is made by manual trial switching (rc). In the last scheme (auto) fault location is done by the substation protection relay and the remote controlled line switch is automatically operated from the control centre by SCADA.

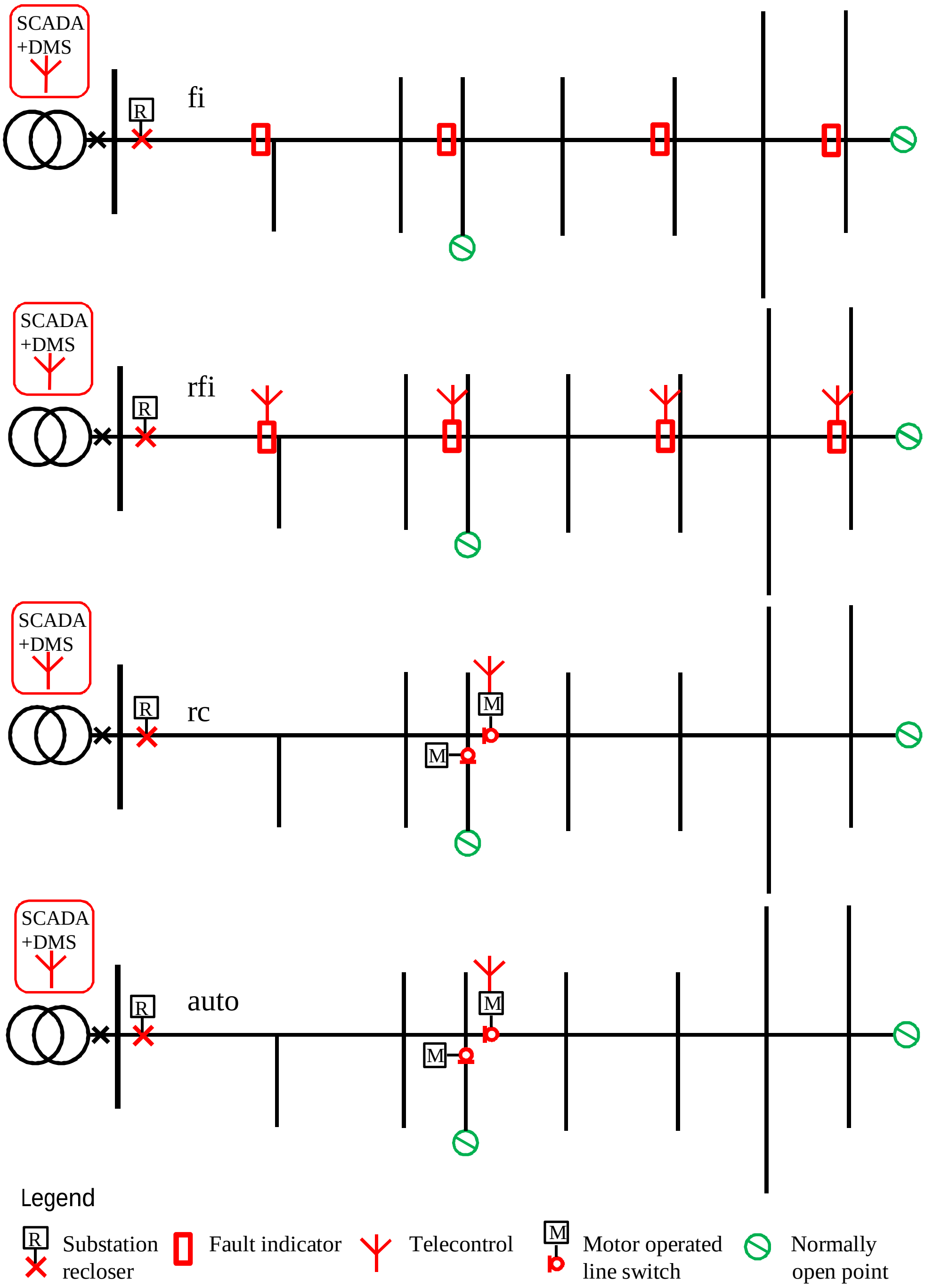


Figure 31. The studied remote control related feeder automation schemes.

Table 11. The studied remote control related feeder automation schemes (Figure 31 on the previous page).

ID	Automation scheme
man	No automation, basic comparison level
fi	Manual switching and locally read and set fault indicators in every second distribution substation of the feeder trunk line
rfi	Manual switching and remote read and set fault indicators in every second distribution substation of the feeder trunk line
rc	Remote control of the line switch group between the first and second halves of the feeder. Fault location is made by trial switching.
auto	Fault location is performed by the substation protection relay and automatic operation by SCADA of the remote controlled line switch group between the first and second part of the feeder

3.6.2 Line reclosing schemes

To improve electricity distribution reliability indices and reduce the annual total outage cost a feeder trunk can be divided into two or more sectionalising zones by using remote operated line reclosers with reclosing capability. In addition to the indices characterising the average interruption frequency (*T–SAIFI*) and interruption duration (*T–SAIDI*), a line recloser also improves *T–MAIFI*, an index indicating the average momentary interruption frequency, since faults in the receiving end of the line do not cause reclosings in the supplying end. Adding the first recloser brings the largest benefit, amounting theoretically to a 25 % improvement in *T–SAIFI* of a homogenous feeder.

An inherent way to add zones to the network is to separate the lateral lines of a feeder to zones of their own. Lateral lines from 20 kV trunk lines can also be built with 1000 V technology, in which case the lateral line and its protection forms a protection zone of its own thus preventing a fault in the lateral line from affecting the rest of the network.

A solution of particular interest is a semiconductor switch/recloser in front of the lateral line. At present, the power-electronic semiconductor devices are reaching the performance level required for this purpose, especially when the fault currents far downstream from the primary distribution substation are usually relatively low. The opening of a semiconductor circuit-breaker is about 50 ms faster than that of a traditional one, and thus, reasonably short protection tripping times in the entire feeder can be achieved. In the 1000 V low-voltage system, a semiconductor switch is assumedly a feasible solution at present (Kumpulainen et al. 2006: 15).

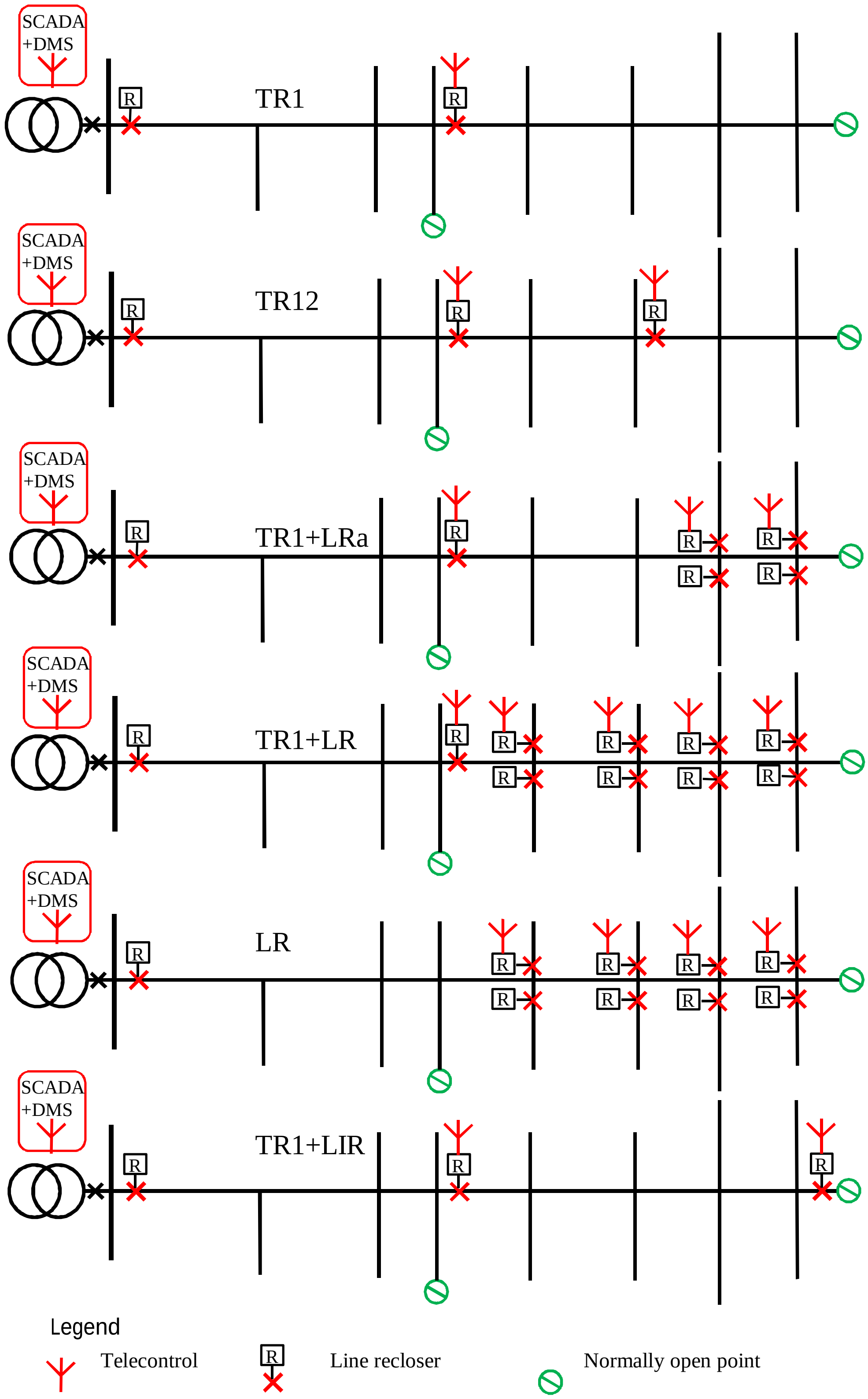


Figure 32. The studied line reclosing feeder automation schemes.

In this study several sectionalisation schemes are examined (Figure 32 on the previous page, Table 12). The two main aspects are sectionalisation of the feeder trunk line and sectionalisation of the feeder lateral lines. The exact location of a recloser is mostly determined by other circumstances than the annual total outage cost.

Regarding the sectionalisation of the trunk line the first stage is to add one recloser between the first and second part of the feeder. Thus faults in the second half of the feeder are automatically isolated. The second case to be studied is a second recloser halfway downstream of the second part of the trunk line. The sectionalisation of the laterals is studied as three different cases. In the first scheme there is a trunk recloser between the first and second part of the trunk line and furthermore the longest laterals at the end of the feeder are equipped with remote operated line reclosers. The second scheme is a similar scheme but with line reclosers in all the laterals. The third scheme has line reclosers in all the laterals of the second part of the feeder. The last scheme studied is one trunk line recloser together with a linking recloser at the normally open point at the feeder end.

Table 12. The analysed sectionalisation schemes.

ID	**Sectionalisation scheme** (Figure 32 on the previous page)
TR1	A remote operated line recloser in the beginning of the second part of the feeder trunk line
TR12	A remote operated line recloser in the beginning (TR1) and a second remote operated line recloser in the middle (TR2) of the second part of the feeder trunk line
TR1+LRa	A remote operated line recloser in the beginning of the second part of the feeder trunk line (TR1) and remote operated line reclosers in the long lateral lines of the second part of the feeder trunk line (LRa)
TR1+LR	A remote operated line recloser in the beginning of the second part of the feeder trunk line (TR1) and remote operated line reclosers in all the lateral lines of the second part of the feeder trunk line (LR)
LR	Remote operated line reclosers in all the lateral lines of the second part of the feeder trunk line
TR1+LIR	A remote operated line recloser in the beginning of the second part of the feeder trunk line (TR1) and a linking recloser (LIR), located at the normally open point at the end of the feeder trunk line

3.7 The reliability indices of the designed generic feeders

The system level electricity distribution reliability indices are calculated according to Chapter 2.2.4. The charts in Figure 33 present the effect of the different feeder automation schemes on the electricity distribution reliability indices of the different generic feeders.

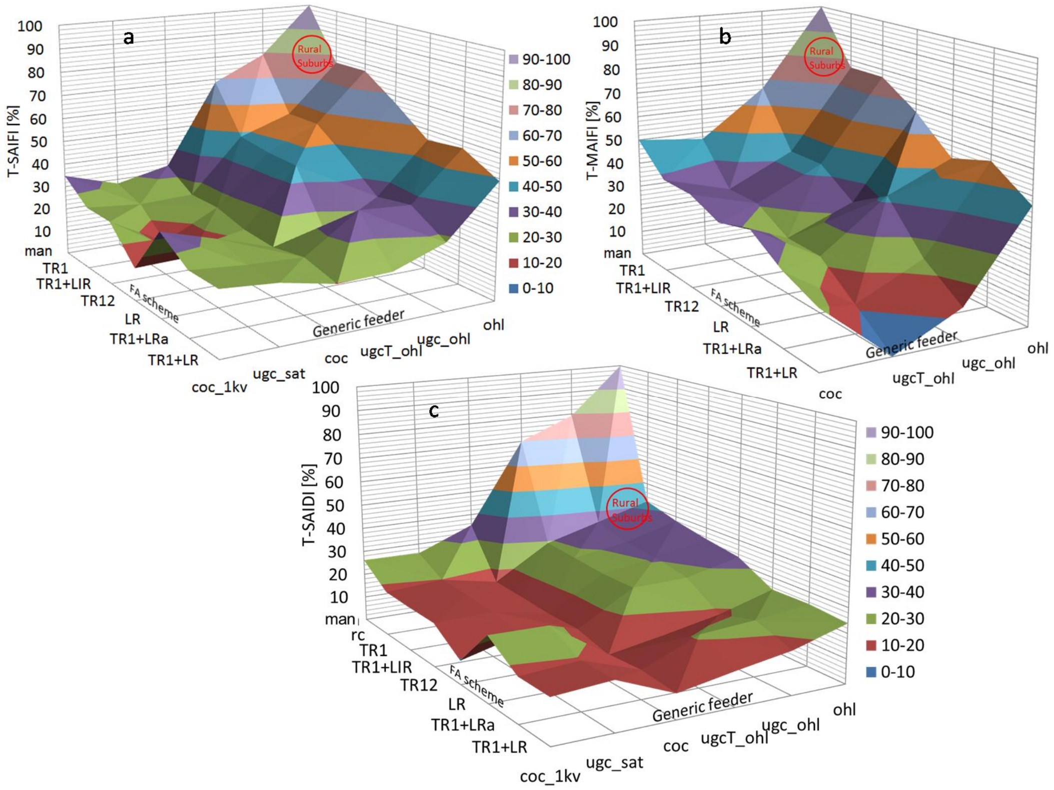
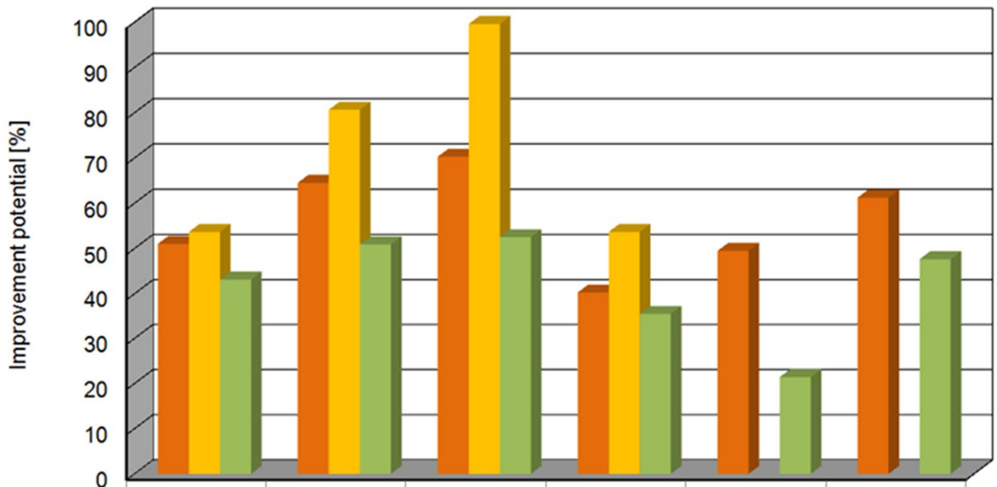


Figure 33. The calculated percentage *T–SAIFI* (a), *T–MAIFI* (b) and *T–SAIDI* (c) of the different generic feeders as a function of the different FA schemes. The comparison level is the generic ohl model feeder with only manually operated line switches. The present expected average rural/sub-urban performance level is marked with a red circle.

Since the reliability indices are influenced by the feeder line total length the indices are presented as a percentage of the indices of the generic ohl model feeder with only manually operated line switches. The average Finnish standard, which corresponds to one remote controlled line switch group, is marked in the charts. Because line reclosing has not yet widely been used the improvement potential of *T–SAIFI* and *T–MAIFI* is high. Due to a high implementation of remote operation of line switches *T–SAIDI* has improved with about 50 %. Still there are improvement possibilities by using more reliable network feeders than overhead line feeders or/and using different line reclosing schemes. In Figure 34 the improvement potential by using line reclosing for the different generic model feeders compared to remote control of line switch groups is presented. As can be seen there is a substantial improvement potential for the three reliability indices by using line reclosing. This can also be seen from the expressions of the reliability indices of long feeders in Table 2 (page 51) by comparing the expressions of feeders with and without line sectionalisation. When the number of sectionalisation zones grows the expression for the reliability indices goes towards a half of the expression of the indices without sectionalisation.



	ohl	ugc_ohl	ugcT_ohl	coc	ugc_sat	coc_1kv
T-SAIFI	51	65	70	40	49	61
T-MAIFI	54	81	99,6	54		
T-SAIDI	43	51	52	35	21	48

Figure 34. The improvement potential of the distribution substation level reliability indices of the different generic model feeders compared to the same model feeder with remote operated line switches halfway downstream of the feeder (rc scheme).

3.8 Summary

To be able to compare the performance and economy of different network types and feeder automation schemes and the interaction and influence of these on different investment strategies six different generic model distribution systems have been designed. In the design of the primary distribution substation distribution area statistics from both Finnish geodesy and distribution company annual average data have been analysed and applied.

Different feeder automation schemes have been designed to be applied to all the designed model feeders. While the protection of the feeders in Finnish medium voltage distribution systems mainly is concentrated to the primary distribution substation the designed feeder automation schemes also include remote operated line reclosers along the second part of the model feeders both on the trunk line and the lateral lines. In the different line reclosing schemes the number and location of line reclosers are varied. The effects of the sectionalisation schemes on the reliability indices of the designed generic model feeders are compared. It has been shown that by using remote control of line switches the improvement of the average *T–SAIDI* of the Finnish sub-urban and rural distribution system has been in the order of 50 %, while average *T–SAIFI* and *T–MAIFI* have not improved. It has also been shown that by using different line reclosing schemes there is yet another improvement potential of about 50 %. A question is how cost-effective the use of the whole improvement potential is. This will be developed further in the next chapters.

4 THE ANNUAL COST OF ELECTRICITY DISTRIBUTION OF THE GENERIC FEEDERS

To benefit from the incentives in the Finnish regulation model, adapted since 2008, the distribution companies could optimize their cost of investment, operation and maintenance. In this chapter, calculations of the costs that are significantly influenced by the feeder type and automation scheme are calculated and presented. With regard to the operational costs, only the cost of losses is taken into consideration, while the costs of maintenance and repair are considered to be in the same order of size for the different generic distribution systems and are therefore omitted from this work. The costs are studied on an annual basis. The electricity distribution annual total cost can be given by the following equation:

$$C_{TOT} = C_{INV} + C_{OPE} + C_{INT}, \tag{43}$$

where

C_{INV} = the annual investment cost
C_{OPE} = the annual operation cost
C_{INT} = the annual total outage cost

The total outage cost is:

$$C_{INT} = C_{rep} + C_{com} + C_{NDE} + C_{AR} + C_{DIP}, \tag{44}$$

where

C_{rep} = the cost for repairing the fault
C_{com} = the cost for compensation to customers due to the outage
C_{NDE} = the cost for non-delivered energy
C_{AR} = the cost of auto-reclosing
C_{DIP} = the cost of voltage dips

The cost of fault repairing and customer compensation depend mainly on the distribution system category (rural, urban, city) and are not in the scope of this research. Because the number of voltage dips cannot be reduced by the use of feeder automation the cost of voltage dips are not included in the study.

4.1 The annual investment cost of the generic model feeders

The total investment cost is converted to annual investment cost using the annuity method. Amortization times used are for land, buildings and components 30 years and the interest rate used is 6 %. The annual investment cost is (Lakervi 2008: 43):

$$C_{INV} = C_{con} \cdot \varepsilon \,, \tag{45}$$

where

C_{con} = the total construction cost
ε = the annuity factor

$$\varepsilon = \frac{p/100}{1 - \dfrac{1}{(1 - p/100)^t}} \,, \tag{46}$$

where

p = the interest rate
t = the study period of the investment

The cost information used is from the national unit cost of network components, including installation, annually updated and published by the Energy Market Authority (EMA 2010). The feeder construction cost consists of the cost of the primary distribution substation allocated to the feeders, the cost of lines and terminals, digging, poles, distribution substations and transformers, protection equipment, automation equipment and installation. The primary distribution substation costs include the cost of the site, the cost of the outdoor switchyard, primary distribution transformers, substation foundation and housing, indoor medium voltage switchgear, distribution management system (DMS), network information system (NIS), customer information system (CIS), and installation. Because the primary distribution substation feeds several feeders the substation cost is divided by the number of feeders for allocation to the individual feeder cost. Figure 35 presents the annual investment cost of the different generic model feeders. As can be expected the underground cable feeders have an investment cost of almost twice that of overhead line feeders, while the coated overhead conductor line based feeders have an investment cost of medium level.

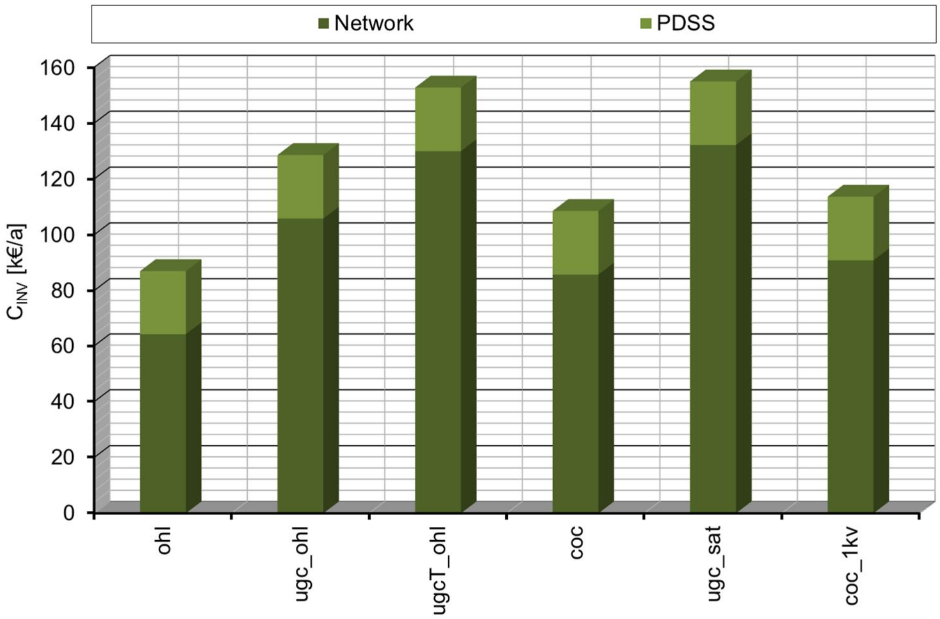


Figure 35. The annual investment cost of the different generic feeders without feeder automation when the amortization time is 30 years and the interest rate is 6 %.

4.2 The cost of losses

The cost of losses consists of the primary distribution transformer losses, the line losses and the losses of the distribution transformers. The primary distribution transformer losses are:

$$P_{hp} = P_{hp0} + P_{hplo}, \tag{47}$$

where

P_{hp0} = the no-load losses of the primary distribution transformer
P_{hplo} = the load losses of the primary distribution transformers

The primary distribution transformer load losses are:

$$P_{hplo} = LL^2 \cdot P_{hpcu}, \tag{48}$$

where

LL = the loading level of the primary distribution transformer
P_{hpcu} = the copper losses of the primary distribution transformer

The line losses are:

$$P_{hl} = 3 \cdot \sum I_i^{\,2} \cdot r_{ui} \cdot L_i \ , \tag{49}$$

where

I_i = the current in line section i
r_{ui} = the resistance per unit length of line section i
L_i = the length of line section i

The distribution transformer losses are:

$$P_{hd} = P_{hd\,0} + P_{hdlo}, \tag{50}$$

where

P_{hd0} = the no-load losses of the distribution transformers
P_{hdlo} = the load losses of the distribution transformers

The load losses are:

$$P_{hdlo} = LL^2 \cdot P_{hdcu}, \tag{51}$$

where

LL = the loading level of the distribution transformers
P_{hdcu} = the copper losses of the distribution transformers

The total power losses are:

$$P_{htot} = P_{hp0} + P_{h1} + P_{hd0} \tag{52}$$

The total loss energy is:

$$W_{htot} = P_{hl} \cdot t_h + 8760 \cdot \left(P_{hp0} + P_{hd0}\right), \tag{53}$$

where

t_h = peak operating time of losses = LLF x 8760 h = 1000 h (Lohjala 2005: 76)
LLF = the loss load factor (Lakervi 1996: 36)

The cost of losses is:

$$C_h = C_p \cdot P_{htot} + C_w \cdot W_{htot} \ , \tag{54}$$

where

C_p = 30 €/kW, a (Lohjala 2005: 70)
Cw = 0.03 €/kWh (Lohjala 2005: 70)

The annual total cost of losses for the different generic model feeders are shown in Figure 36. As can be seen the cost of the distribution transformer losses is the most significant loss cost. Normal distribution transformer loss data has been used in this calculation. However distribution transformers with reduced power losses are also available. The coc_1kV feeder has the highest annual cost of losses due to high losses in the 1000 V lateral lines and higher distribution transformer losses.

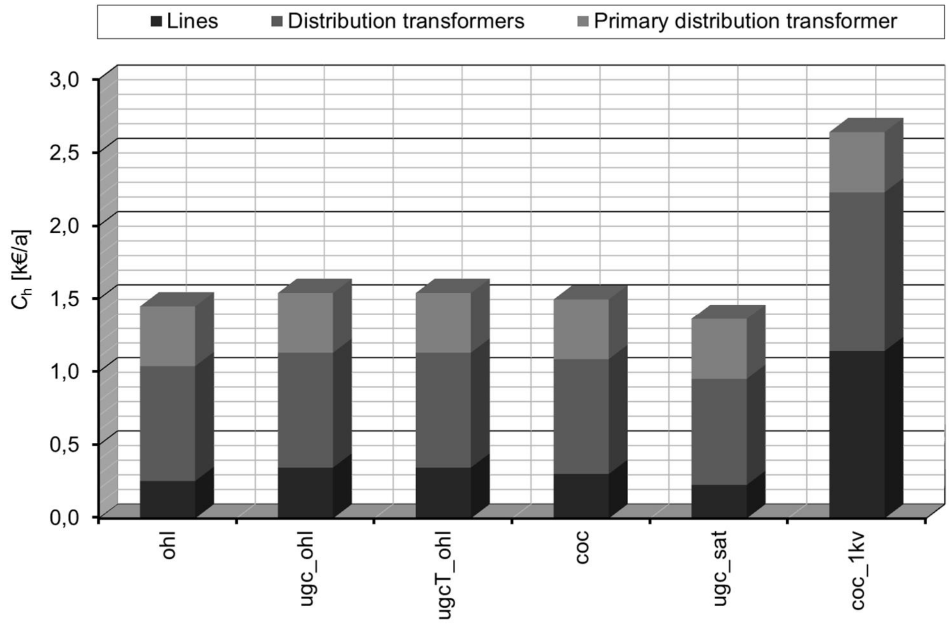


Figure 36. The annual cost of losses of the different generic model feeders.

4.3 The cost of non-delivered energy

For the calculation of the cost of non-delivered energy the generic feeders are modelled as large component groups considering that all the included components in a group act in the same way regarding reliability. The equivalent switching time caused by a component fault depends on how the faulted component, the load point, network protection, automation and backup connections are situated in relation to each other (Lakervi et al.1996: 75). To obtain the switching times for different automation schemes the restoration process is modelled and the switching times for different feeder automation schemes are calculated as in Appendix 11. The restoration process is modelled as a two-stage process where the first stage includes separating the first and second part of the feeders from each other by opening the feeder trunk line switch in the distribution substation between the first and second part of the feeders and isolating the fault by opening the line switches on both sides of the fault. In the second stage the feeder configuration is restored to its normal condition after the repair of the faulty component. The unit cost of non-delivered energy and auto-reclosing are specified by the Finnish Energy Market Authority for year 2005. The values are corrected according to the construction index to correspond to the price level in year 2010 (Table 13).

Table 13. Specified and corrected unit cost values for the calculation of the annual total outage cost.

Unit cost	**2005** (Honkapuro et al. 2007a: 35)	**2010** (EMA 2007 a: 66–67)
NDE [€/kW]	1.10	1.42
NDE [€/kWh]	11.0	14.2
HSAR [€/ kW]	0.55	0.71
DAR [€/ kW]	1.10	1.42

The cost of NDE of the different generic model feeders with different remote control related feeder automation schemes calculated according to the method given in Chapter 2.4.2 is presented in Figure 37 a. As can be seen the cost of non-delivered energy in Finnish overhead line distribution systems has been reduced to about a half of its initial value by the use of remote operated line switches. Figure 37 b presents the possibilities to further reduce the cost of non-delivered energy by using different feeder types and/or line reclosing schemes.

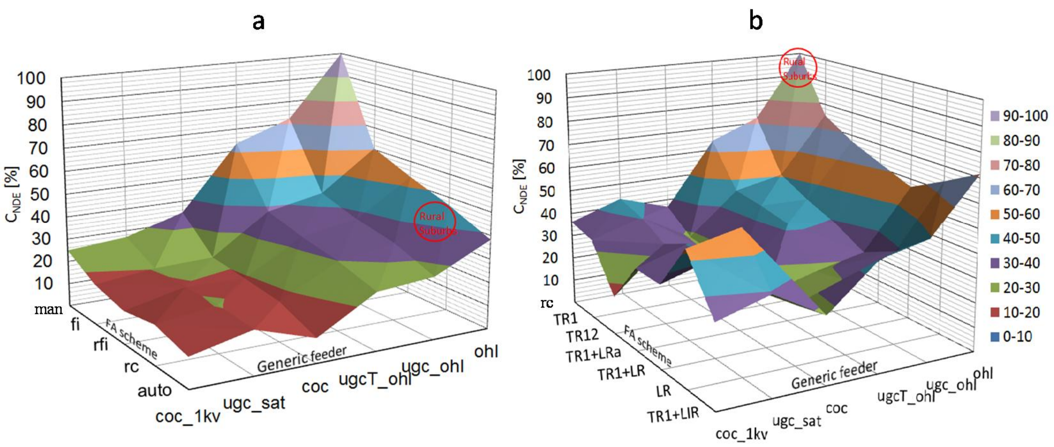


Figure 37. (a) The percentage annual cost of NDE of the different generic model feeders with different remote control related feeder automation schemes when compared to the ohl generic feeder with only manually operated line switches. 100 % corresponds to an annual cost of NDE of 27.8 k€. (b) The percentage annual cost of NDE of the different generic model feeders with different line reclosing schemes when compared to the ohl generic feeder with a remote operated line switch group halfway downstream of the feeder trunk line. 100 % corresponds to an annual cost of NDE of 13 k€.

4.4 The annual cost of auto-reclosing

In feeders with auto-reclosing schemes the total outage cost also includes the cost of auto-reclosing. For the calculation of the cost of auto-reclosing, statistics from the Finnish Energy Industries are utilised (FEI 2004). For Finnish neutral isolated networks the annual average number of auto-reclosing was 51 per 100 km of overhead line. Thus the cost of auto-reclosing can be calculated using Equation 37 on page 52. According to the results, presented in Figure 38, there is a huge potential to reduce the cost of auto-reclosing by using other than overhead lines or line reclosing in overhead line feeders.

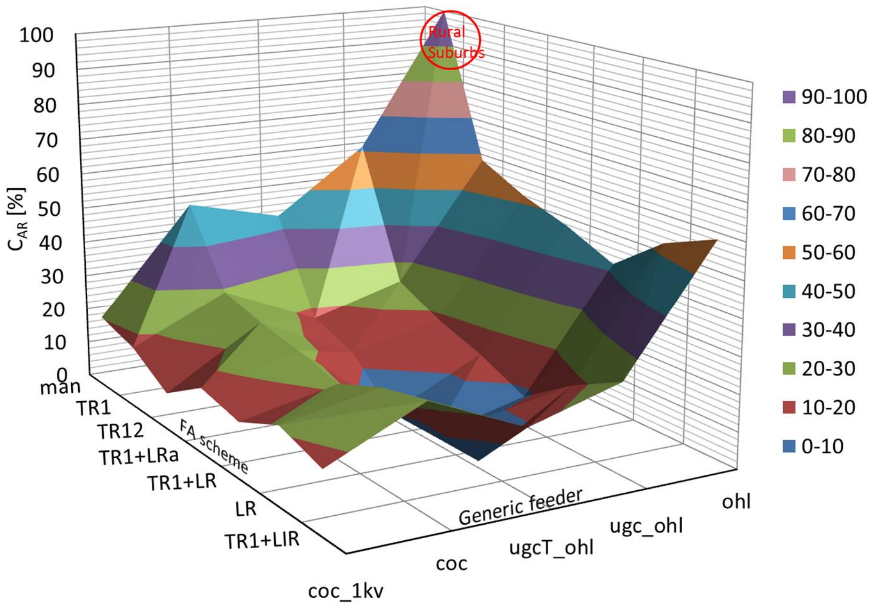


Figure 38. The influence of different line reclosing schemes on the percentage cost of auto-reclosing of the different generic model feeders where 100 % corresponds to an annual cost of 22 k€. The present national average sub-urban/rural level is marked with a red circle.

4.5 The annual total outage cost of the generic model feeders

The annual total outage cost of the generic model feeders can now be calculated by adding the annual cost of NDE and AR (Figure 39). Because remote control of line switches does not reduce the cost of auto-reclosing the reduction of the total outage cost is only in the order of 30 %. Thus with line reclosing the annual total outage cost of the different feeders can be further reduced. The satellite distribution system has the lowest annual total outage cost. It has to be noticed that the annual total outage cost is a direct function of the feeder average power.

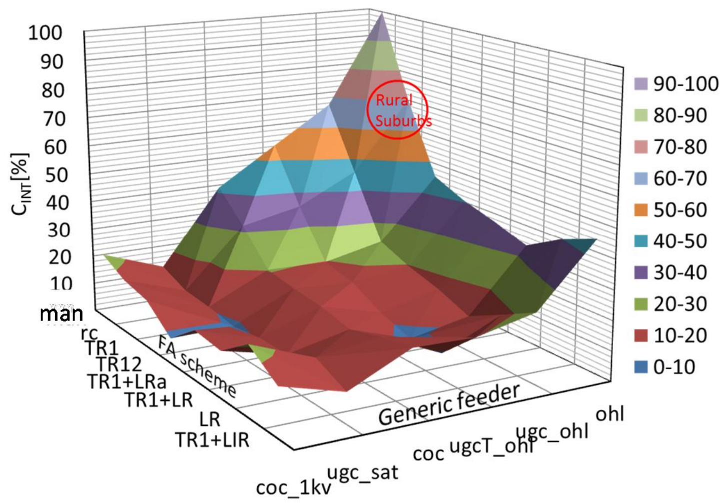


Figure 39. The impact of feeder automation scheme on the annual total outage cost of the different generic model feeders where 100 % corresponds to an annual total outage cost of 50 k€. The present national average sub-urban/rural level is marked with a red circle.

4.6 The total annual cost of the different generic feeders

The annual total cost of the generic model feeders studied, which include the annual investment cost, the annual cost of losses and the annual total outage cost differ substantially between the different generic feeders (Figure 40 a). Because SCADA is regarded as a strategic investment in Finland as cost for remote control only the DMS cost related to the feeder is included (Appendix 10). With no feeder automation the coc_1kV and coc generic feeders have the lowest annual total cost. With a remote operated switch group the ohl generic feeder is the most economical (Figure 40 b). The minimum annual total cost has the generic ohl model feeder equipped with two line reclosers. According to the results it is possible to further reduce the annual total cost of Finnish sub-urban/rural distribution systems by using line reclosing schemes. The cost reduction level is dependent on the cabling level of the network (Figure 40 c).

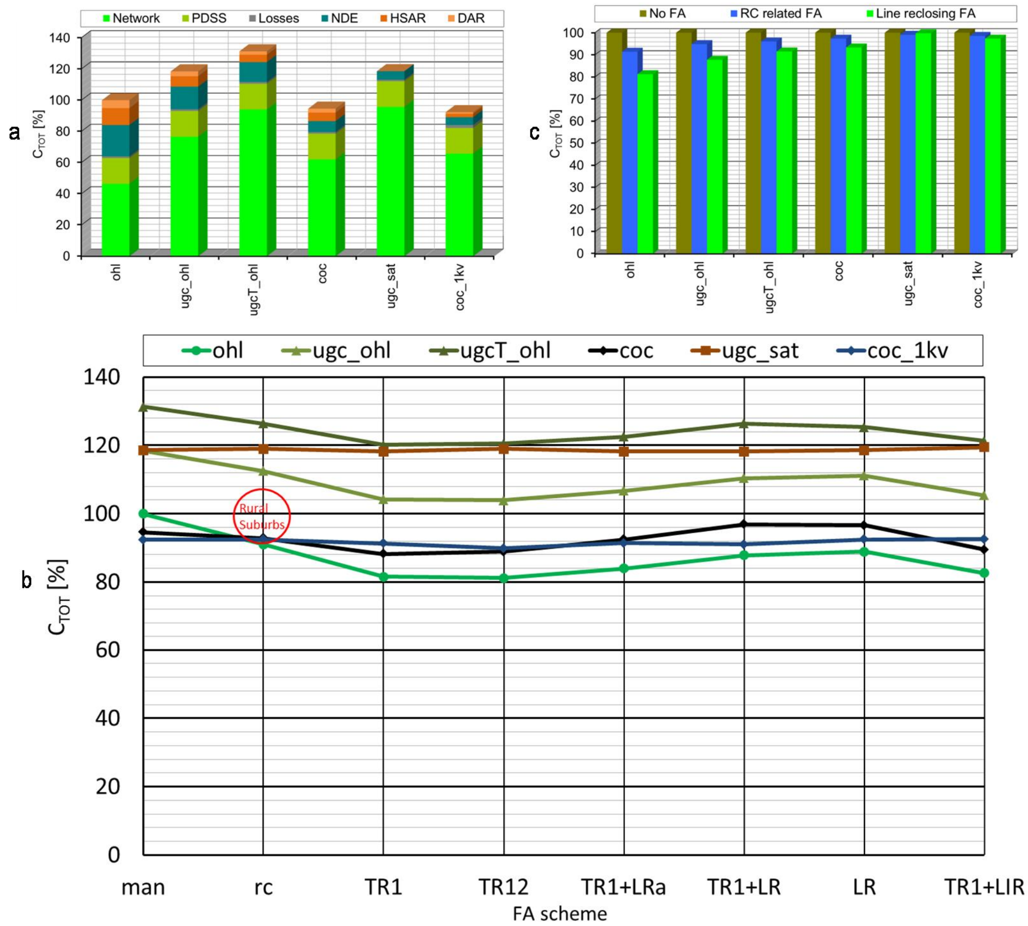


Figure 40. (a) The annual total cost of the different generic feeders. (b) The impact of FA scheme on the annual total cost of the different generic feeders. (c) Minimum annual total cost of the different generic feeders with an isolated system neutral without FA, with remote control related FA and with line reclosing FA. In (a) and (b) the comparison level is the ohl generic feeder with no FA where 100 % corresponds to the annual total cost of 138 k€.

4.7 Optimum location

The starting-point of evaluating the cost-efficiency of line-reclosing is the calculation of the total outage cost by equations in Table 3 on page 53. As has been found cost efficiency is achieved either by reducing the annual total outage cost of components with a high fault-frequency, e.g. overhead lines or by installing line reclosers in inhomogeneous parts of the network. According to the equations differences in the properties of the different parts of the network may be found regarding fault-frequency, outage unit cost values, average power, auto-reclosing frequency and auto-reclosing unit cost values. With respect to feeder section length, average power, line type fault frequency and customer group outage unit cost the following equation gives the optimum location of remote controlled line reclosers:

$$Location = \arg\max_{k} \left(\sum_{i=1}^{i=k} P_i \cdot c_{cgi} \cdot \sum_{j=k+1}^{j=l} L_j \cdot f_j \right), \qquad \textbf{(55)}$$

where

k = the number of different homogenous feeder line sections upstream of recloser
l = the number of total different homogenous feeder line sections
P_i = average power of line section i upstream of the line recloser
c_{cgi} = outage unit cost of customer group in line section i upstream of the line recloser
L_j = total line length of line section j downstream of the line recloser
f_j = fault frequency of line section j downstream of the line recloser

4.8 Summary

It has been shown how feeder type and implemented feeder automation scheme influence the annual total outage and total cost of electricity distribution. When constructing new distribution systems feeders with a minimum annual total cost are chosen while in old existing distribution systems the main attention is on the annual total outage cost. It has also been shown that in neutral isolated distribution systems the overhead line feeder with one or two remote controlled line reclosers has the minimum annual total cost. Existing overhead line networks have the highest annual total outage cost which have been reduced by the use of remote controlled line switch groups. Further reduction is achieved by the use of remote controlled line reclosers. When deciding upon network investments the total outage cost reduction and the payback time of the different investment options are two main issues. In the next chapter the cost-efficiency of different investment options will be calculated and presented.

5 BENEFITS AND COST EFFICIENCY OF DIFFERENT INVESTMENTS

According to Willis there are four interrelated concepts which form the cornerstones of optimized reliability planning. They are benefit/cost analysis, incremental benefit/cost analysis, systems approach and distributed reliability.

> Optimizing power system reliability implies obtaining the best reliability for a given amount of money, or spending the least possible to obtain a specific reliability target. The mechanism upon which optimization works is a comparison of one project or program or opportunity against others, with the more cost-effective items rising to the top of the priority list and less effective sinking to the bottom (Willis 2004: 1063).

In this chapter the benefit or saving, benefit/cost, incremental benefit/cost and payback time of different generic feeder automation schemes and other network investments are studied.

5.1 The economic benefit, benefit/cost, incremental benefit/cost and payback time of different reliability improving investments

5.1.1 *The annual economic benefit of feeder automation*

The annual benefit or cost saving of feeder automation is calculated by comparing the annual total outage cost of the reliability improving investment to the total outage cost of the feeder before the investment. The annual benefit of the reliability improving investment i is:

$$B_i = C_{INT} - C_{INTi} \,, \tag{56}$$

where

C_{INT} = the annual total outage cost without the investment *i*
C_{INTi} = the annual total outage cost with the investment *i*

In Figure 41 the influence of the different line reclosing schemes on the annual cost saving of the different generic feeders is presented when the comparison level is no existing feeder automation (a) and a remote controlled line switch group halfway downstream the feeder (b). The annual total outage cost saving potential for the mixed generic model feeders with line reclosing is about twice in (a) compared to (b). The highest annual cost saving is achieved with the generic ohl feeder and the line reclosing scheme TR1+LR.

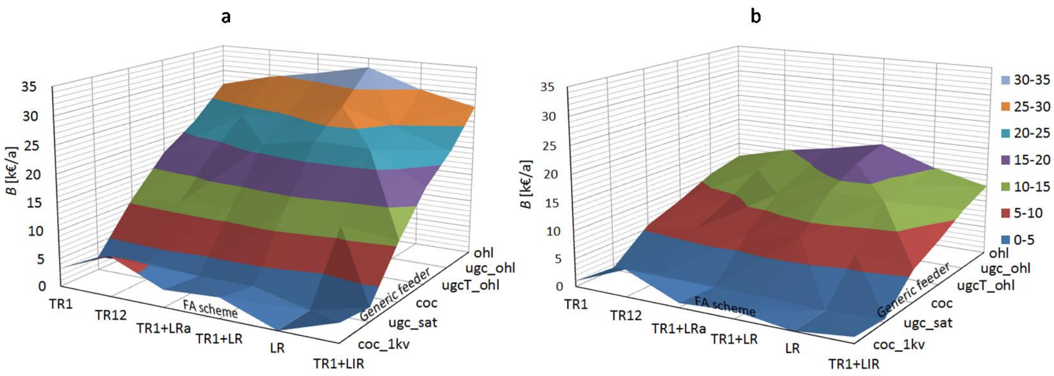


Figure 41. The annual total outage cost saving of the remote controlled line recloser schemes of the different generic feeders when the comparison level is no FA (a) and a remote controlled line switch group halfway downstream of the feeder trunk line (b).

5.1.2 *The benefit/cost of the different automation schemes*

The benefit per cost ratio is used for various efficiency or cost-reduction programs where spending on optional projects is justified only when benefits outweigh costs. Here the annual total outage cost saving of an investment is compared to the annual total outage cost without the investment. The benefit/cost is:

$$B/C = \frac{C_{INTi-1} - C_{INTi}}{C_{INVi}} \quad , \qquad \textbf{(57)}$$

where

C_{INTi-1} = the annual total outage cost without the investment
C_{INTi} = the annual total outage cost with investment i
C_{INVi} = the annual cost of investment i

The cost of the investment includes the total equipment investment cost including installation while the annual benefit is the annual total outage cost saving achieved by the use of the investment in question. In Figure 42 the annual benefit/cost of the different feeder automation schemes is presented.

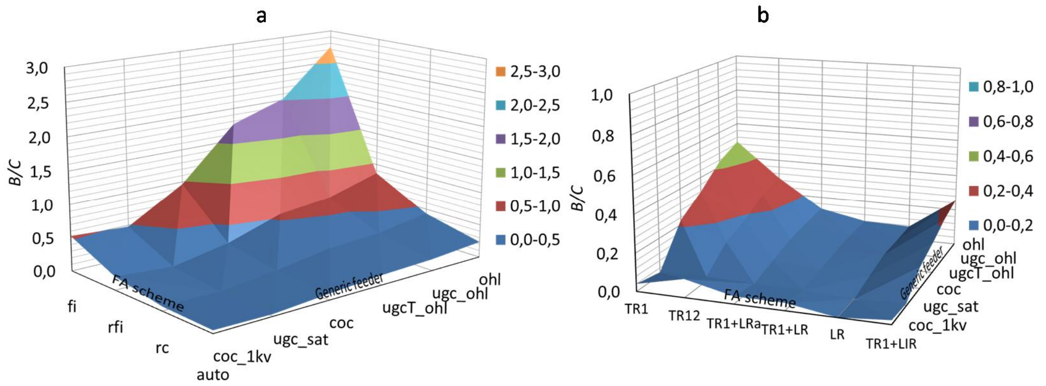


Figure 42. Annual benefit/investment cost of remote control related FA schemes when the comparison level is no FA (a) and remote controlled line recloser schemes when the comparison level is a remote controlled line switch group halfway downstream of the feeder trunk line (b).

5.1.3 *The incremental benefit/cost of the different automation schemes*

When the investment with the highest annual benefit/cost is found a second investment may also be cost-effective. This is calculated by assuming that the first investment is already performed. When changing from one line reclosing scheme to another, available equipment needed are reused when possible, and only the cost of new automation equipment is included. The incremental benefit/cost is thus:

$$incB/C = \frac{C_{INTi} - C_{INTi+1}}{C_{INVi+1}} \, , \qquad \textbf{(58)}$$

where

C_{INTi+1} = the annual total outage cost of investment i+1
C_{INV+1} = the additional cost of investment i+1

The incremental benefit/cost expresses how cost-effective it is to change the feeder automation scheme from one scheme to another scheme. Because TR1 was the most cost-effective feeder automation scheme Figure 43 shows that changing the feeder automation system from this scheme to another scheme is not very cost-effective. As only a few (1–2) automation schemes are cost-effective it is extremely important to find the most cost-effective automation scheme in the first place because also the investment order influences the cost/benefit results. Therefore the calculation of the cost-efficiency of different investment strategies has to be done one step at a time so that the cost-efficiency of each single investment is known.

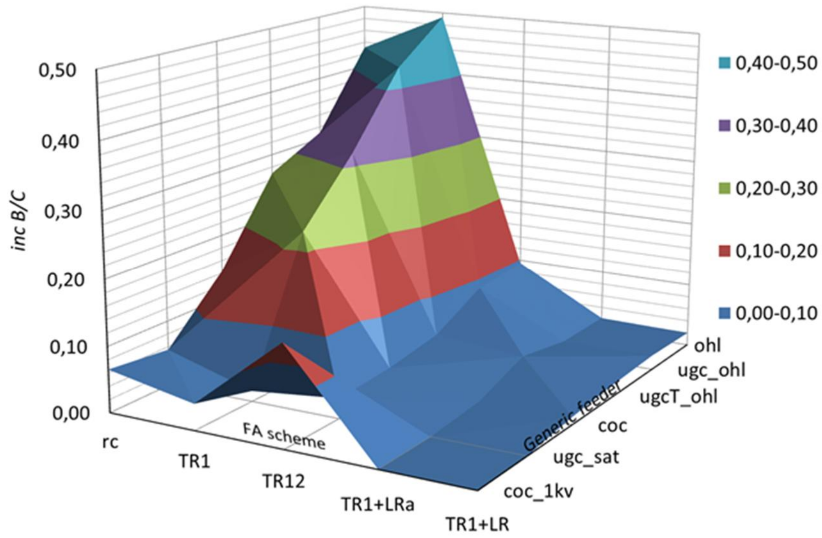


Figure 43. The incremental benefit/cost of different FA schemes.

5.1.4 *The payback time of the different feeder automation schemes*

When comparing different alternative investment strategies the payback time of the different alternatives is of great importance. The payback time T_{PBi} of the investment *i* is:

$$T_{PBi} = \frac{C_{INVtoti}}{B_{INTi}} \quad , \tag{59}$$

where

$C_{INVtoti}$ = the total cost of investment *i*
B_{INTi} = the annual total outage cost saving of investment *i*

The results show that the network type highly influences the payback time of the different feeder automation schemes (Figure 44). Because the overhead line feeder has the highest annual total outage cost, it has also the shortest payback times of the different feeder automation schemes. For the remote control related feeder automation schemes the comparison level is the basic distribution system with no feeder automation (a) and for the line reclosing schemes a remote controlled line switch group (b). As can be seen the payback time for the line reclosing schemes are more scattered than those for the remote control related schemes. Fault indication is a low-cost fault location system and has therefore a short payback time, while remote control of line switches is more expensive with a payback time of a few years in overhead line networks. The payback time of the most cost-effective line reclosing scheme (TR1) is around two years in overhead line networks. From the calculations not presented here it can be concluded that the payback times of the line reclosing schemes are typically reduced by about 50 % if there is no existing feeder automation in the network.

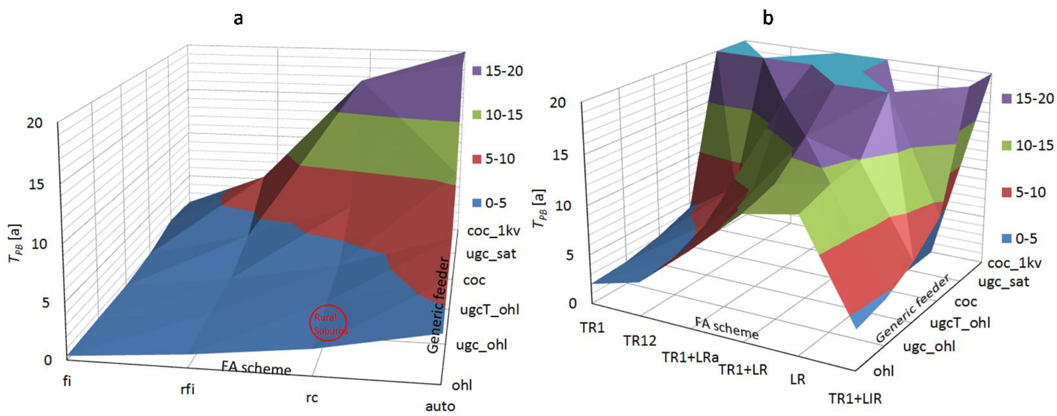


Figure 44. The payback time of different remote control related FA schemes when the comparison level is no present FA (a) and a remote controlled line switch group halfway downstream of the feeder trunk line (b).

5.1.5 *The feeder automation scheme impact on the regional annual total outage cost level*

The regional impact of the different feeder automation schemes differs in terms of both the different generic feeder models and feeder automation schemes. In Figure 45 the regional impact of feeder automation scheme on the ohl generic feeder is presented. In Figure (a) the comparison level is no feeder automation. Remote control of a line switch group reduces the annual total outage cost in all the feeder regions while a remote controlled trunk line recloser further reduces the outage cost of the first part of the feeder. Increasing the number of line reclosers reduces the annual outage cost of the lateral area of the second halve of the feeder. In (b) the ratio of the annual total outage cost between the first/second half and lateral/trunk line of the feeder is presented. The latter ratio differs substantially depending on the implemented feeder automation scheme. The feeder automation scheme is thus a means for optimising the outage cost for different customer groups with regard to regional location.

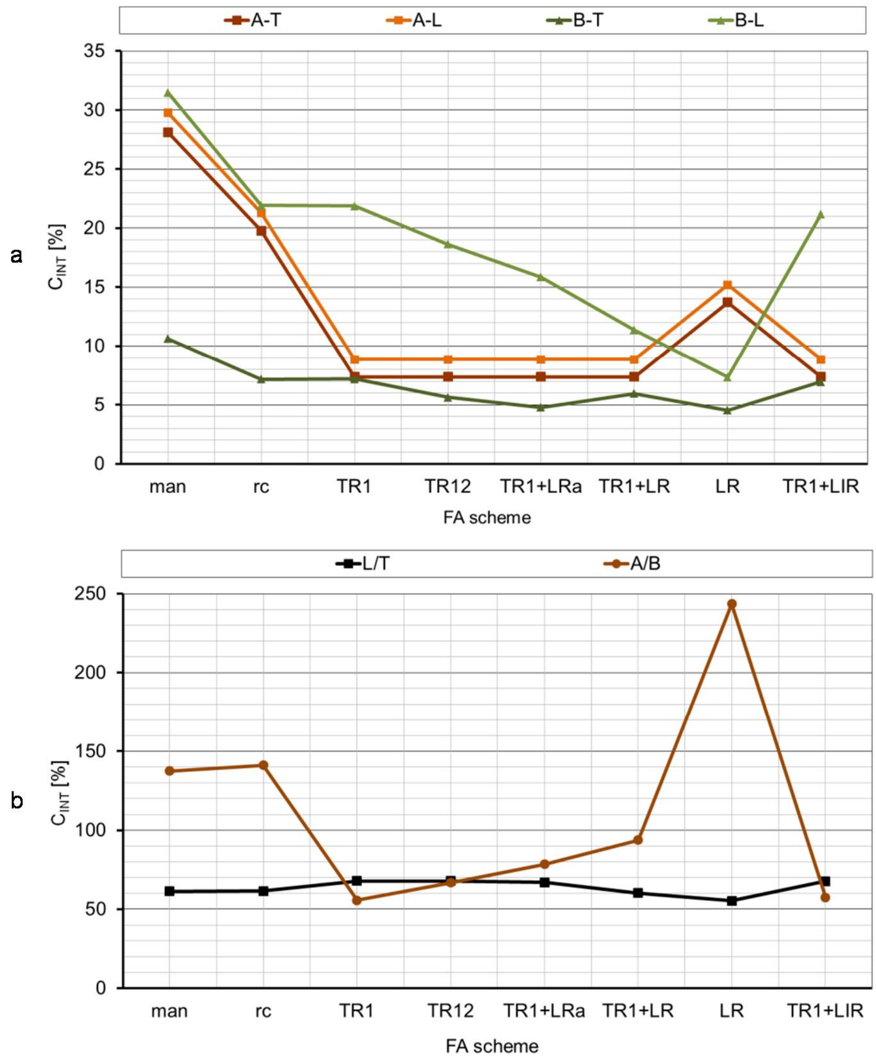


Figure 45. Annual total outage cost share of the different regions of the ohl generic feeder (a), feeder lateral/trunk line and first/second part of the line (b). A = feeder first part, B = feeder second part, T = trunk line, L = lateral lines.

5.2 The influence of feeder type and automation scheme on the economy of other reliability improving investment programs

When deciding upon investment programs, other than feeder automation investments programs, it is essential to know how present and future automation schemes influence the profitability of the investment program concerned. The economic benefits of the following investment programs of the different generic model feeders as a function of the different feeder automation schemes are studied:

- Adding a second primary distribution substation to the interface between two primary substation distribution areas
- Adding a switching station between the first and second part of the feeder or the end of the feeder
- Changing the feeder lines from overhead line to coated overhead conductor or underground cable line
- Central earth-fault current compensation of the generic distribution system

In the next section the cost efficiency of improving electricity distribution reliability and thus reducing the total outage cost by installing a second primary distribution substation and switching stations to the different feeders is studied.

5.2.1 A new primary distribution substation and a switching station along the feeder

The potential sites for a new substation and a switching station (Figure 46):

- Assuming that the original substation has only one (16 MVA) primary distribution transformer there is a potential for a second primary distribution substation on the original site or at the end of the feeder (Case A)
- Installing a switching station at point B halfway downstream the feeder trunk line (Case B)
- Installing a switching station at point C of the feeder

Adding a second primary distribution substation between two existing substations (case A) halves the average feeder length and thus the total outage cost C_{INT} is on average halved:

$$C_{INT} = 0.5 \cdot \left(C_{NDE} + C_{AR}\right) \tag{60}$$

As a matter of fact the result is identical to the total outage cost calculated for the different generic model feeders with different automation schemes. The total cost of the investment is presented in Table 14. The payback time of a new primary distribution substation between two existing substations calculated so that the feeder automation scheme is the same before and after the investment is presented in Figure 47. As can be seen from the figure, depending on the feeder type and feeder automation scheme, the payback time varies from a few years up to over 50 years.

Case A:

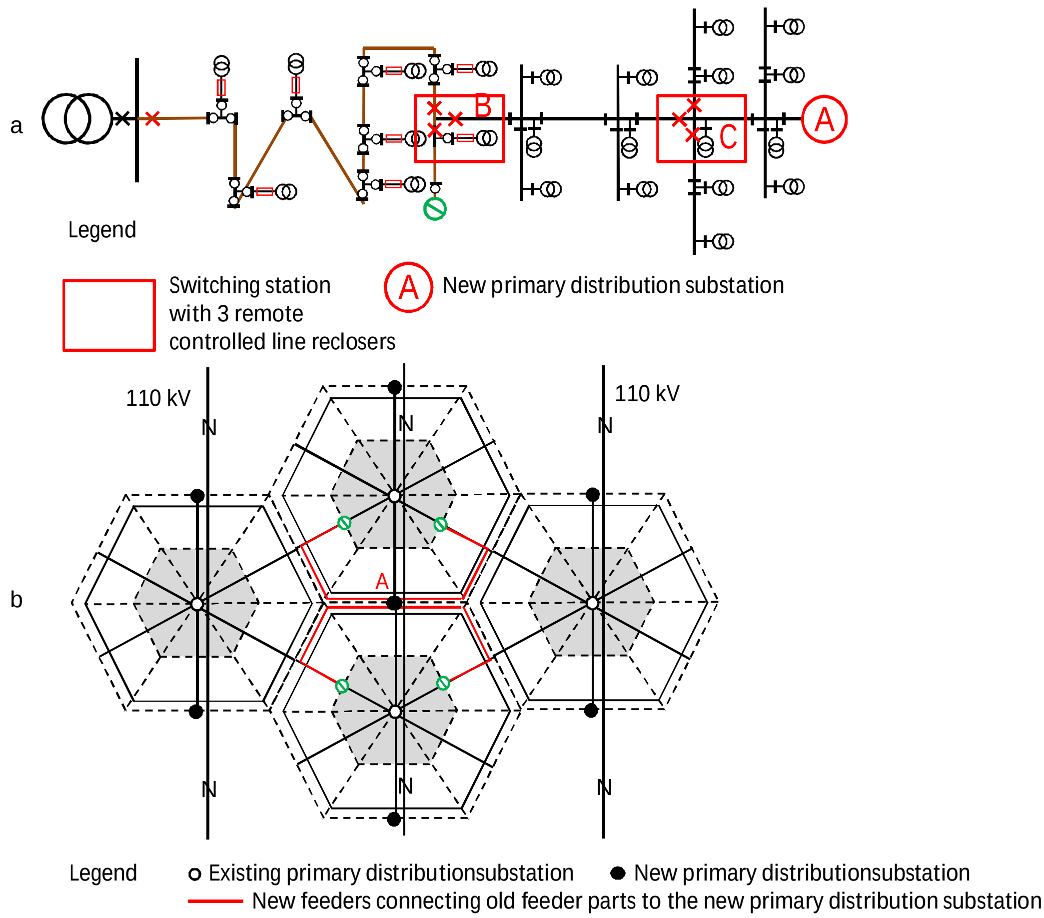


Figure 46. (a) Investment options A, B and C. Investment option A comprises a new primary distribution substation at the boundary between two primary distribution substations. Investment B is a switching station halfway downstream of the feeder trunk line while investment C is a switching station towards the end of the feeder trunk line. (b) The new primary distribution substations marked with black dots feed the outer parts of the existing primary distribution substation service areas while the existing primary distribution substations feed the inner substation service areas (shadowed).

As the Finnish overhead line feeders often contain some portion of underground cable and remote operated line switch groups the payback time is often longer than 10 years. Increasing substation density also reduces the propagation of voltage dips. The effect of the reduced number of voltage dips has however not been incorporated into the calculation of economic benefits of a new substation. In case the feeders are mixed feeders (OHL/UGC) an advantage could also be that the overhead line feeders and the underground cable feeder can be fed from their own primary distribution substations. Anyhow a case-specific study shall be performed to demonstrate the cost-efficiency.

Table 14. The cost of adding a second primary distribution substation or a switching station to the original primary distribution substation service area (Figure 46 on the previous page). The switching station (B or C) is based on distribution substation technology.

Case	Investment cost [k€]						
	Substation	Land	Line 20 kV	110 kV	Transformer	Installation	Total
A	800	60	500	260	303	200	2123
B	88	10	6			50	154
C	88	10	8			100	206

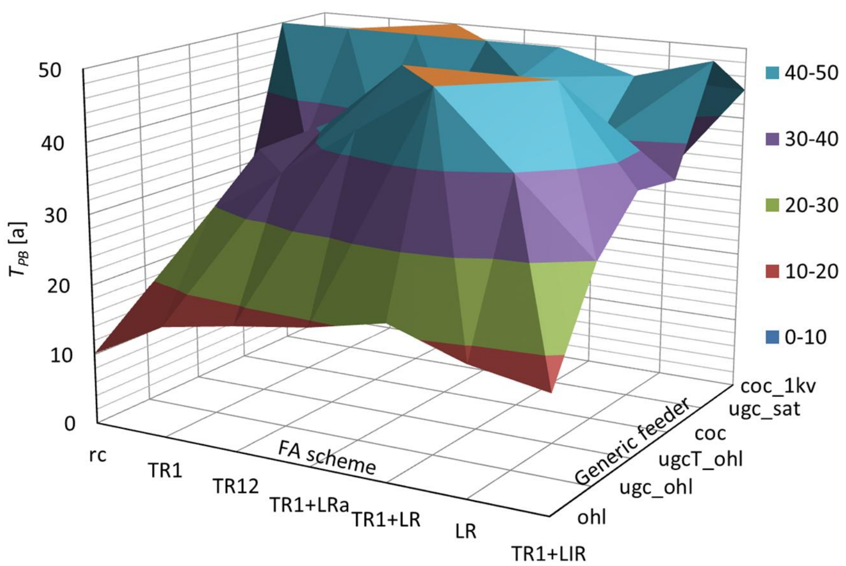
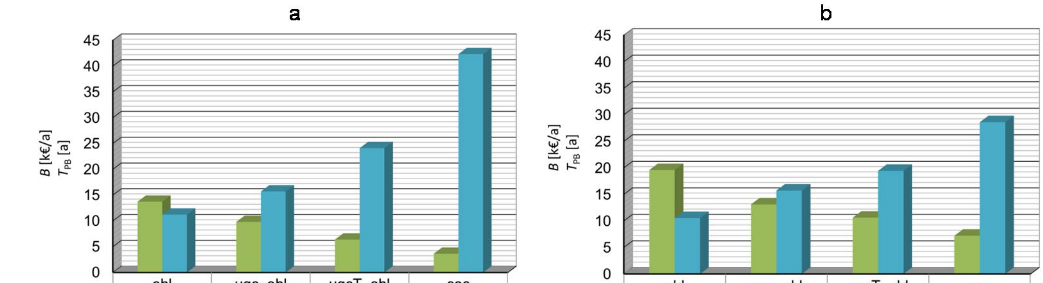


Figure 47. The payback time of a second primary distribution substation at the interface of two existing adjacent primary distribution substations as a function of the feeder type and FA scheme. The FA scheme before and after the investment is the same.

Case B and C:

Calculation of the payback time of switching stations is made only to generic feeders containing overhead lines or overhead conductor lines, because the annual cost saving of other feeders is not high enough to give a reasonable short payback time. The calculation is made for two locations of switching stations, between the first and second part of the model feeders and towards the end of the feeders. Here the calculations for the former location are presented. The total outage cost is compared to the total outage cost with no existing feeder automation.

The annual economic benefit and the payback time of a switching station halfway downstream of the different generic feeders studied here are presented in Figure 48 a. Here the comparison level is remote controlled line switch groups halfway downstream of the feeders. As can be seen the payback times are quite long. The annual economic benefit and the payback time of a switching station at the end of the different generic feeders are presented in Figure 48 b. Here the comparison level is no feeder automation. A switching station towards the end of the feeder is not cost-effective if remote controlled line switches already exist. If the feeder is very long and there is a long branch at the switching station location a case-specific study may be necessary to examine the cost-effectiveness.



a	ohl	ugc_ohl	ugcT_ohl	coc
Annual saving	13,7	9,8	6,4	3,6
Payback time	11,2	15,7	24,1	42,3

b	ohl	ugc_ohl	ugcT_ohl	coc
Annual saving	19,6	13,1	10,6	7,2
Payback time	10,5	15,7	19,4	28,6

Figure 48. The annual economic benefit and payback time of installing a switching station halfway downstream the feeder trunk line when the comparison level is the feeder equipped with a remote controlled line switch group (a) and towards the end of the feeder when the comparison level is no FA (b). Included costs are presented in Table 14 on page 98.

5.2.2 *Changing the feeder line from overhead line to underground cable or coated overhead conductor line*

With regard to electricity distribution reliability, underground cable lines have a fault frequency which is about three times lower than overhead lines. Underground cable lines are also considered to be the only weather-proof distribution line. Possible investment options are changing existing overhead lines to other feeder types (Figure 49 a). Investing simultaneously in line reclosers and changing the feeder type shortens the payback time. Remote control of line switches is the comparison level here. This investment alternative is not cost-effective. In Figure 49 b the payback time of the additional cost when constructing a new feeder as another feeder type than originally intended overhead line is presented. Also here the payback times are quite long.

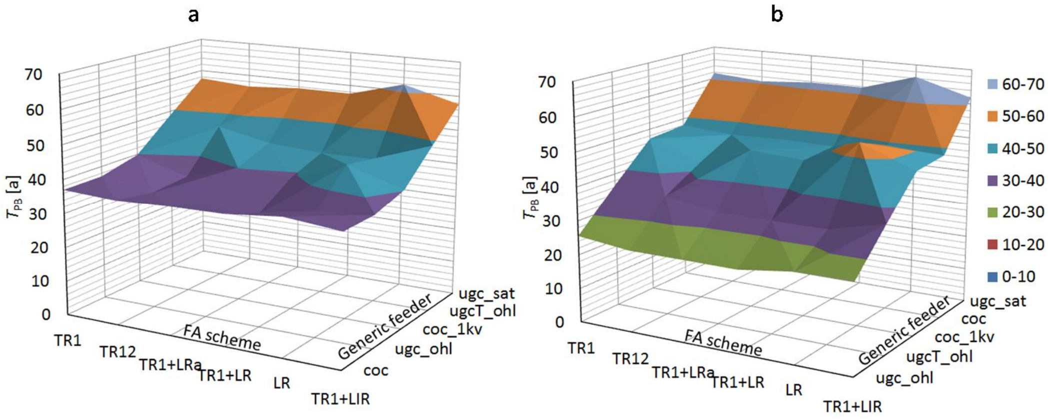


Figure 49. (a) The payback time of changing an existing overhead line feeder (ohl) to another feeder. (b) The payback time of constructing a new feeder as another feeder than an overhead line feeder. The comparison level is a remote controlled line switch group halfway downstream of the feeders.

5.2.3 Central earth-fault current compensation of the generic feeders

Due to the self-extinction of the small residual earth-fault currents in compensated networks, earth-fault current compensation of Finnish neutral isolated overhead line medium-voltage networks decreases the number of earth-faults to about the half of that of neutral isolated networks (FEI 2004: 11). Thus earth-fault current compensation improves *T–MAIFI* and reduces the cost of auto reclosing to about a half of that in neutral isolated distribution systems. However, earth-fault current compensation and line reclosing both reduce the cost of auto-reclosing. The results presented in Figure 50 show that implementing central earth-fault current compensation together with line reclosing is quite cost-effective in networks containing overhead lines. The payback times calculated are valid also for feeders with remote operated line switch groups, because only the cost-savings of auto-reclosing are included.

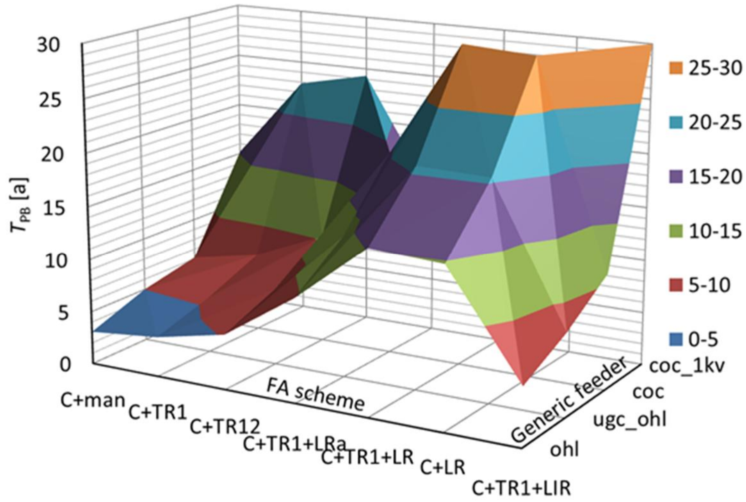


Figure 50. The impact of feeder type on the payback time of central earth-fault current compensation together with different line reclosing schemes. The comparison level is a neutral isolated network without line reclosing. For earth-fault current compensation only the annual cost saving of auto-reclosing is included.

5.3 Comparison of different reliability improving investment strategies

In Figure 51, the payback time of the different studied line reclosing schemes as a function of the annual total outage cost reduction capability of the different generic feeders studied is presented. As can be seen a short payback time mostly means a lower total outage cost reduction and vice versa. Which automation scheme is chosen depends on the goal of the investment. If the distribution reliability improvement is the main goal the total outage cost reduction capability is most important, while a short payback time may be the main target in other cases. In most cases both factors are considered.

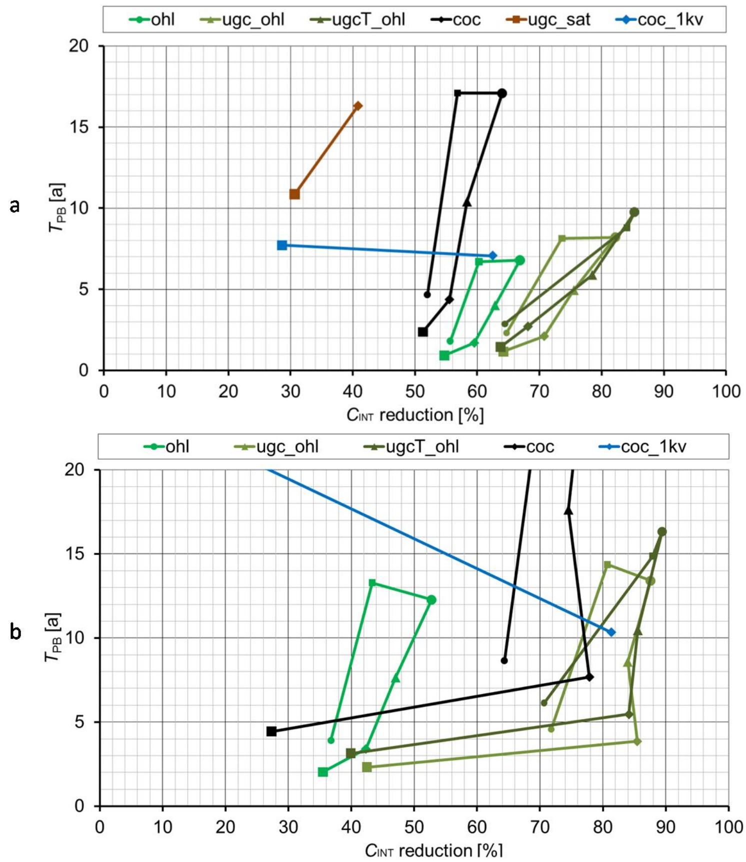


Figure 51. The payback time of the different studied line reclosing schemes as a function of the total outage cost reduction capability of the generic feeders studied. The shaped dots on the lines represent the different feeder automation schemes starting with a large square (TR1) and ending with a small round dot (TR1+LIR). The comparison level is the basic feeders with no FA (a) and a remote controlled line switch group (b).

The payback time of the different reliability improving investments considered as a function of the total outage cost reduction capability of all the studied generic feeders are presented in Figures 52–53. The most efficient investments are the ones with a high total outage cost reduction and shortest payback times. Only investments with a maximum payback time of 20 years are presented. The number of cost efficient alternatives correlates to the feeder type. Optimised special feeders, like the satellite and the 1000 V feeders have few cost-effective investment alternatives. For existing overhead line networks (ohl) fault indication, remote control of line switches and remote controlled line reclosers are very cost-effective investments while a switching station or primary distribution substation improve reliability with a lower cost-efficiency (Figure 52 a). For existing mixed networks (ohl_ugc), fault indication remote control of line switches and line reclosers are cost-effective investments while remote control of line reclosers improves distribution reliability to a great extent. Compared to pure overhead line networks the total outage cost reduction of remote controlled line reclosers has doubled. For the generic ugcT_ohl feeder the most cost-effective investments are fault indication, remote control of line switches and reclosers. For the generic coated overhead conductor feeder the most cost-effective reliability improving investments are fault indication and remote control of line reclosers. For the two optimised generic feeders the only cost-effective investment is fault indication (Figure 53 c).

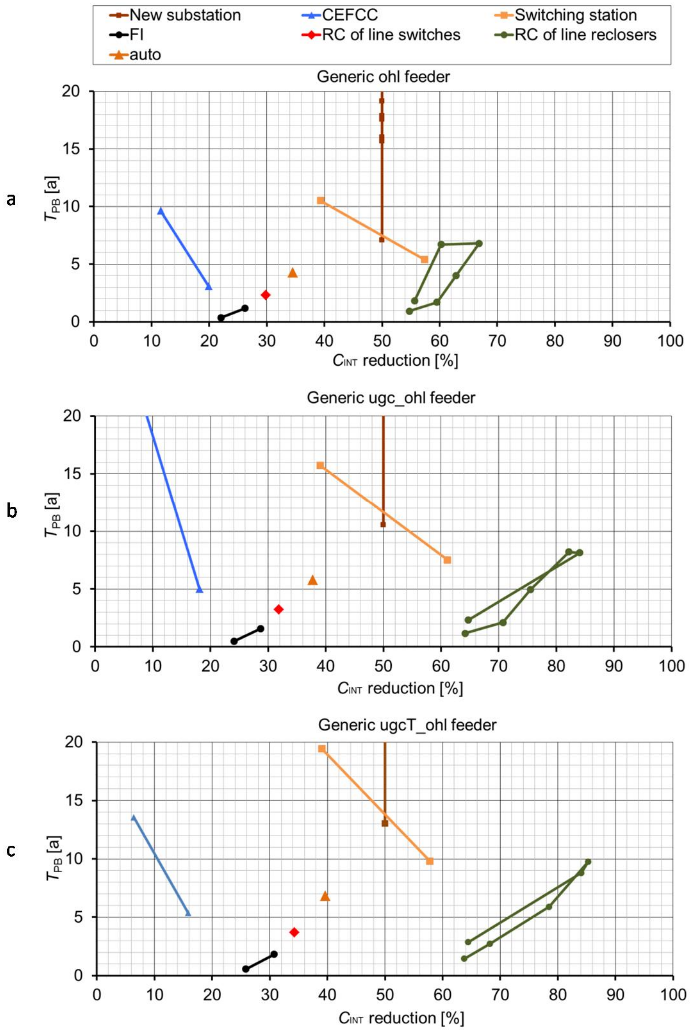


Figure 52. The payback time of the most efficient investments as a function of the total outage cost reduction capability of the generic feeders containing overhead lines. The comparison level is the basic feeders with no FA.

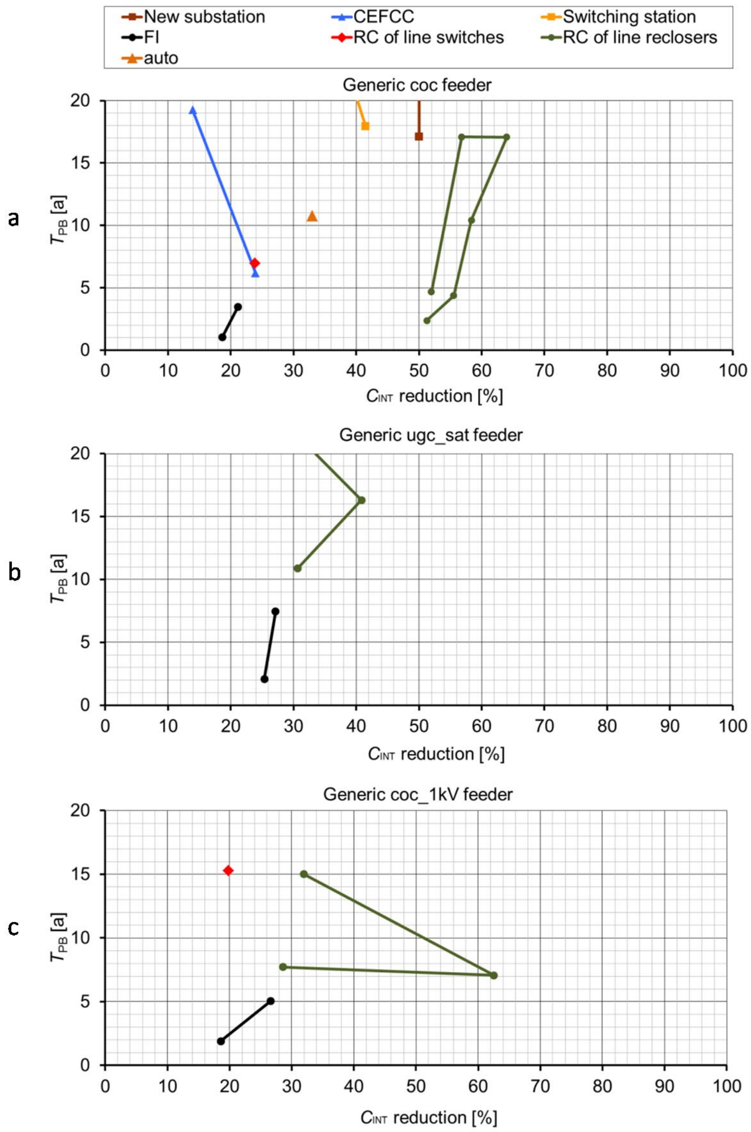


Figure 53. The payback time of the most efficient investments as a function of the total outage cost reduction capability of the generic feeders not containing overhead lines. The comparison level is the basic feeders with no FA.

5.4 The investment impact on the annual total cost of the distribution systems

When constructing new distribution systems, feeders with the minimum annual total cost should be used. In the annual total cost the annual investment cost, the annual cost of losses and the total outage cost are included. When evaluating the feeders, the influence of the feeder automation scheme is included. The total annual cost of the different generic model feeders with different feeder automation schemes are presented in Tables 15 and 16. With no feeder automation the coc_1kV feeder has the lowest annual total cost due to its low annual total outage cost. Using fault indication or remote control of line switches the annual total cost can be reduced by 1–9 % whereby the ohl, coc and coc_1kV generic feeders have the lowest annual total cost. Using line reclosing schemes the annual total cost of the different generic feeders can be reduced by up to 19 % making the overhead line feeder most cost-effective. Combining the results of Table 15 and 16 gives the optimum feeder automation scheme for each generic model feeder. It has been found that the line reclosing schemes give minimum feeder annual total cost. The ugc_sat feeder is the only exception with the fault indication scheme (fi) giving minimum total cost. Thus in neutral isolated networks the ohl generic feeder using the TR12 line reclosing scheme is the feeder with the lowest annual total cost.

In Table 17 the influence of doubling the primary distribution substation density on the annual total cost of the generic feeders with different line reclosing schemes is presented. The results show that only for the ohl feeder the annual total cost is lower than in the original distribution system. This is due to the fact that the generic distribution system is already optimised with regard to primary distribution substation density. In old distribution systems with a high loading level a new primary distribution may be a cost-effective solution to both lower the loading level and improve the quality of supply.

In Table 18 the impact of building a switching station halfway downstream (B) and at the end (C) of the generic feeders on the annual total cost of the feeders are presented. The results show that in existing cost optimised distribution systems, switching stations cannot compete with remote controlled line reclosers with regard to the annual total cost because the cost-efficiency of switching stations is lower than that of single remote controlled line reclosers.

In Table 19 the influence of central earth-fault current compensation on the annual total cost of the generic feeders with different line reclosing schemes is presented. It has been found that the optimal system neutral depends on the generic feeder type. The central earth-fault current compensation together with line reclosing (TR1) gives the global minimum of the annual total cost in the generic distribution system. The results verify that the overhead line network is the most cost-effective system among the studied generic feeders with the input data applied in the calculations here. It has been found that the optimal substation and feeder automation combination depends on the feeder type, network environmental conditions and feeder average power and length. In the next section of the chapter the impact of these on the optimal automation combination will be handled.

Table 15. The annual total cost of the different generic model neutral isolated distribution systems with different remote control related feeder automation schemes.

Feeder	Annual total cost [k€]					Max saving [%]
	man	fi	rfi	rc	auto	
ohl	138	128	126	126	126	8.6
ugc_ohl	164	156	155	156	156	5.2
ugcT_ohl	181	175	174	175	176	4.0
coc	131	127	127	128	129	2.7
ugc_sat	164	162	163	164	167	1.0
coc_1kv	128	126	126	128	130	1.5

Table 16. The annual total cost of the different generic model neutral isolated distribution systems with different remote controlled line recloser schemes.

Feeder	Annual total cost [k€]							Max saving [%]
	man	TR1	TR12	TR1+LRa	TR1+LR	LR	TR1+LIR	
ohl	138	113	112	116	121	123	114	18.8
ugc_ohl	164	144	144	148	153	154	146	12.3
ugcT_ohl	181	166	167	169	175	173	168	8.5
coc	131	122	123	128	134	134	124	6.7
ugc_sat	164	163	164	163	163	164	165	0.3
coc_1kv	128	126	124	126	126	128	128	2.7

Table 17. The impact of doubling the primary distribution substation density on the annual total cost of the generic model neutral isolated distribution systems with different line reclosing schemes. The FA scheme is the same before and after doubling the primary distribution substation density.

Feeder	Annual total cost [k€]							Max saving [%]
	rc	TR1	TR12	TR1+LRa	TR1+LR	LR	TR1+LIR	
ohl	116	115	117	122	130	128	117	7.9
ugc_ohl	158	157	159	164	171	170	159	No further savings compared to Tables 16 and 17
ugcT_ohl	182	181	183	188	196	194	183	
coc	137	137	139	144	151	149	139	
ugc_sat	184	183	185	183	183	181	185	
coc_1kv	144	143	145	143	143	141	145	

Table 18. The impact of a switching station halfway downstream (B) and at the end (C) of the generic neutral isolated distribution systems on the annual total cost.

Feeder	**Annual total cost** [k€]		**Max saving** [%]
	B	C	
ohl	121	134	No further savings compared to Tables 15-17
ugc_ohl	154	166	
ugcT_ohl	177	186	
coc	133	138	

Table 19. The impact of central earth-fault current compensation on the annual total cost of the generic model distribution systems with different line reclosing schemes.

Feeder	**Annual total cost** [k€]							**Max saving** [%]
	man	TR1	TR12	TR1+LRa	TR1+LR	LR	TR1+LIR	
ohl	130	109	109	113	119	120	111	2.7
ugc_ohl	160	144	144	148	154	154	145	0
ugcT_ohl	179	166	167	171	177	175	168	0
coc	127	121	122	127	134	133	123	0.8

5.5 The optimal system neutral and feeder automation scheme

It has been found that the annual total cost minimum of a generic distribution system is defined by the substation and feeder automation combination giving the minimum cost. The minimum annual total cost of the generic distribution system *j* for a specific variable combination (feeder average power, total line length, fault frequency and outage unit cost level) is:

$$\min C_{TOT} = \min\left(\min_{i,j} C_{TOTiso}(i,j), \min_{i,j} C_{TOTcom}(i,j) \right), \qquad \textbf{(61)}$$

where

$C_{TOTiso}(i,j)$ = the annual total cost of investment alternative *i* of the generic feeder *j* with an isolated system neutral

$C_{TOTcom}(i,j)$ = the annual total cost of investment alternative *i* of the generic feeder *j* with an compensated system neutral

As the variable combination of the distribution system vary with time it is of more interest to know the impact of different variable combinations on the automation combination giving minimum annual total cost. Thus the minimum annual total cost of the different generic feeders is studied with respect to the variation of the different properties affecting the annual total cost minimum, varying one property at a time. The variation range of the different properties is given in Appendix 13.1. The factors that affect the feeder annual total cost are: feeder system neutral, line type, implemented feeder automation scheme, feeder average power, outage unit cost level, fault frequency level and total line length. The global minimum annual total cost of the overhead line feeder when the varied properties are at their base level is 109 k€/y. All the basic electricity distribution system variables, such as feeder average power, outage unit cost level and fault frequency level, affect the border value where earth-fault current compensation and more complicated feeder automation schemes become cost-effective.

The impact of varying feeder average power, total line length, fault frequency and outage unit cost on the neutral system and feeder automation scheme giving annual total cost minimum of the different generic feeders are studied here by varying one or two of each of the four different variables at a time within a range of 50–200 % of the values used in the study while the value of the other variables remains unchanged. The variation range is expressed by the variation ladders k_P for feeder average power, k_L for feeder total line length, k_{ouc} for the outage unit cost and k_{ff} for the fault frequency (Appendix 13.2).

The percentage impact on the annual total cost of the different feeders is compared to the basic level of the annual total cost of the ohl generic feeder. Because the feeder average power and length are the most interesting variables they are chosen as parameters. The annual total cost minimum of the different generic feeders is valid only for the combination of the respective feeder neutral system and automation scheme. To simplify the discussion of the results a definition of the value ranges of the variation ladders is also presented in Appendix 13.2.

The impact of feeder average power and total line length on the optimal neutral system and feeder automation scheme combination of the different generic feeders is presented in Figure 54. It has been found that the relative cost effectiveness of long mixed feeders is lower than that of short feeders. With increasing feeder average power the annual total cost minimum of the ohl generic feeder approaches that of the coc and coc_1kV generic feeders. With the exception of the ugc_sat generic feeder, earth-fault current compensation and more complicated feeder automation schemes become cost-effective with increasing feeder average power. The earth fault current compensation with the TR12 feeder automation scheme is the optimal system neutral of overhead line feeders. For short overhead line feeders with an average power of maximum 1.4 MW the optimal feeder automation scheme is however TR1. Also for coated overhead conductor line feeders earth-fault current compensation is the optimal neutral system together with the TR12 feeder automation scheme in long feeders while the TR1 feeder automation scheme is optimal for short feeders. The optimal combination of the 1000 V system depends on the feeder average power and total line length. The optimal feeder automation scheme is however TR12. For the mixed ugc_ohl line feeder with a maximum average power of 1.8 MW an isolated neutral system is optimal while earth-fault current compensation is more suitable for feeders with higher average power. The related feeder automation scheme is TR12 for long feeders and TR1/TR12 for short feeders. For the ugcT_ohl feeder the transition average power limit values vary but the feeder automation scheme is TR1 for short feeders and TR12 for longer feeders.

The impact of feeder line total length and average power on the optimal neutral system and feeder automation scheme of the different generic feeders is presented in Figure 55. It is found that the relative cost-effectiveness between the different feeders increases with increasing length of the feeders while it decreases with increasing average power. In medium and high average power overhead line feeders earth-fault current compensation together with TR1/TR12 feeder automation scheme gives minimum annual total cost while isolated/earth-fault current compensated neutral together with TR1/TR12 feeder automation scheme is optimal in low average power overhead line feeders. For the coated overhead conductor feeder the picture is the same but the border values are slightly higher than for the overhead line feeder. The optimum combination of the ugc_sat feeder is an isolated neutral together with the fi feeder automation scheme. The TR12 feeder automation scheme is optimal only in long feeders with medium or high average power. For the 1000 V system an isolated neutral system together with TR1/TR12 feeder automation system is optimal while earth-fault current compensation is efficient in long feeders with a high average power. In mixed line feeders with a moderate average power an isolated neutral together with TR1/TR12 feeder automation scheme gives minimum annual total cost. Earth-fault current compensation is needed only in long and high loaded ugc_ohl feeders. The impact of the outage unit cost and fault frequency level on the optimal automation combination scheme is presented in the sensitivity analysis in Chapter 7.3.

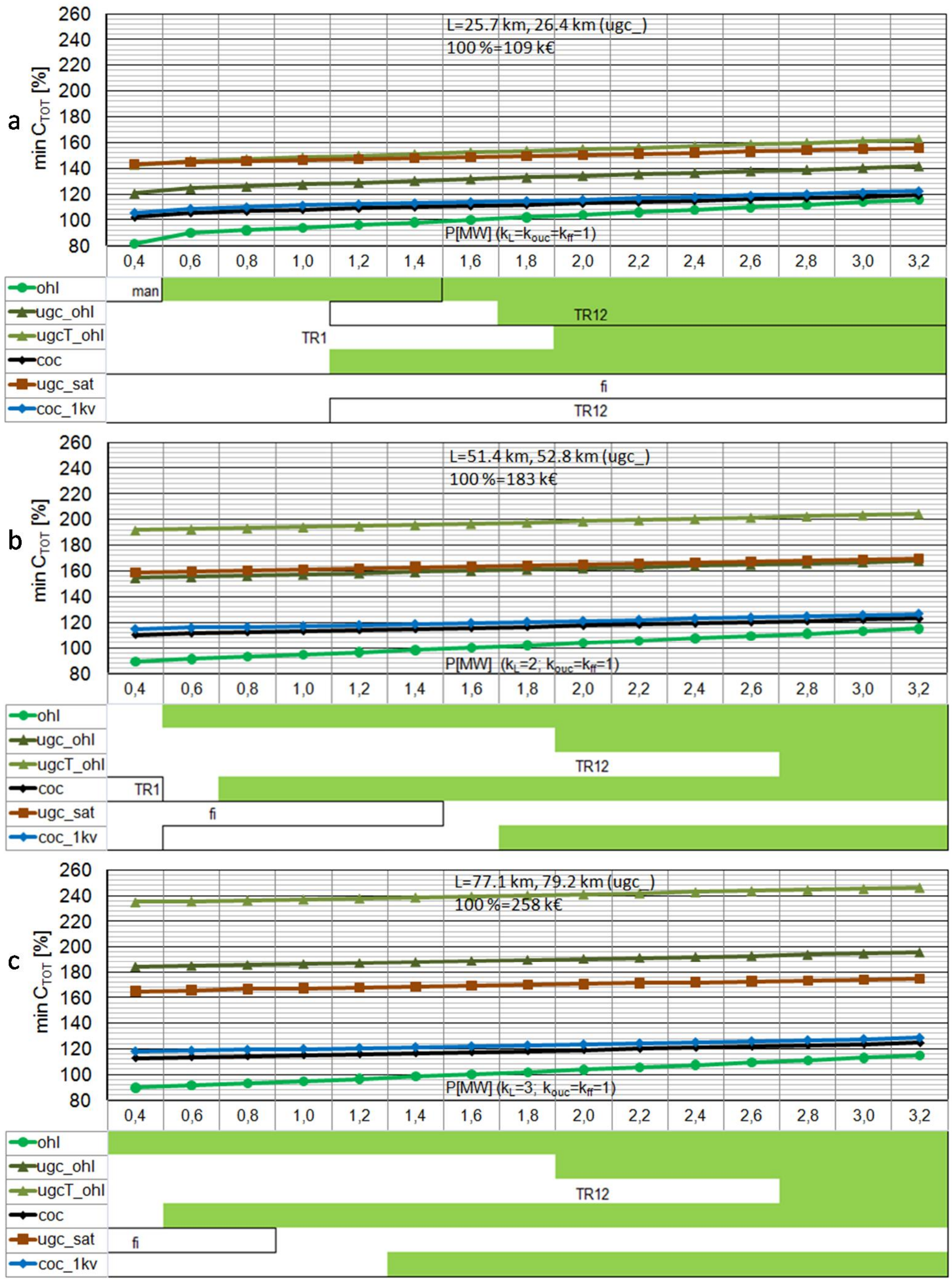


Figure 54. The impact of feeder average power and total line length on the optimal neutral system and FA scheme with regard to the minimum annual total cost of the different generic feeders. The comparison level is the ohl generic feeder with the average power variation ladder value set to 1. The line total length variation ladder is 1 (a), 2 (b) and 3 (c). The feeder neutral system/FA scheme is given by the colour and ID in the x-axis table where white indicates an isolated neutral system and green earth-fault current compensation.

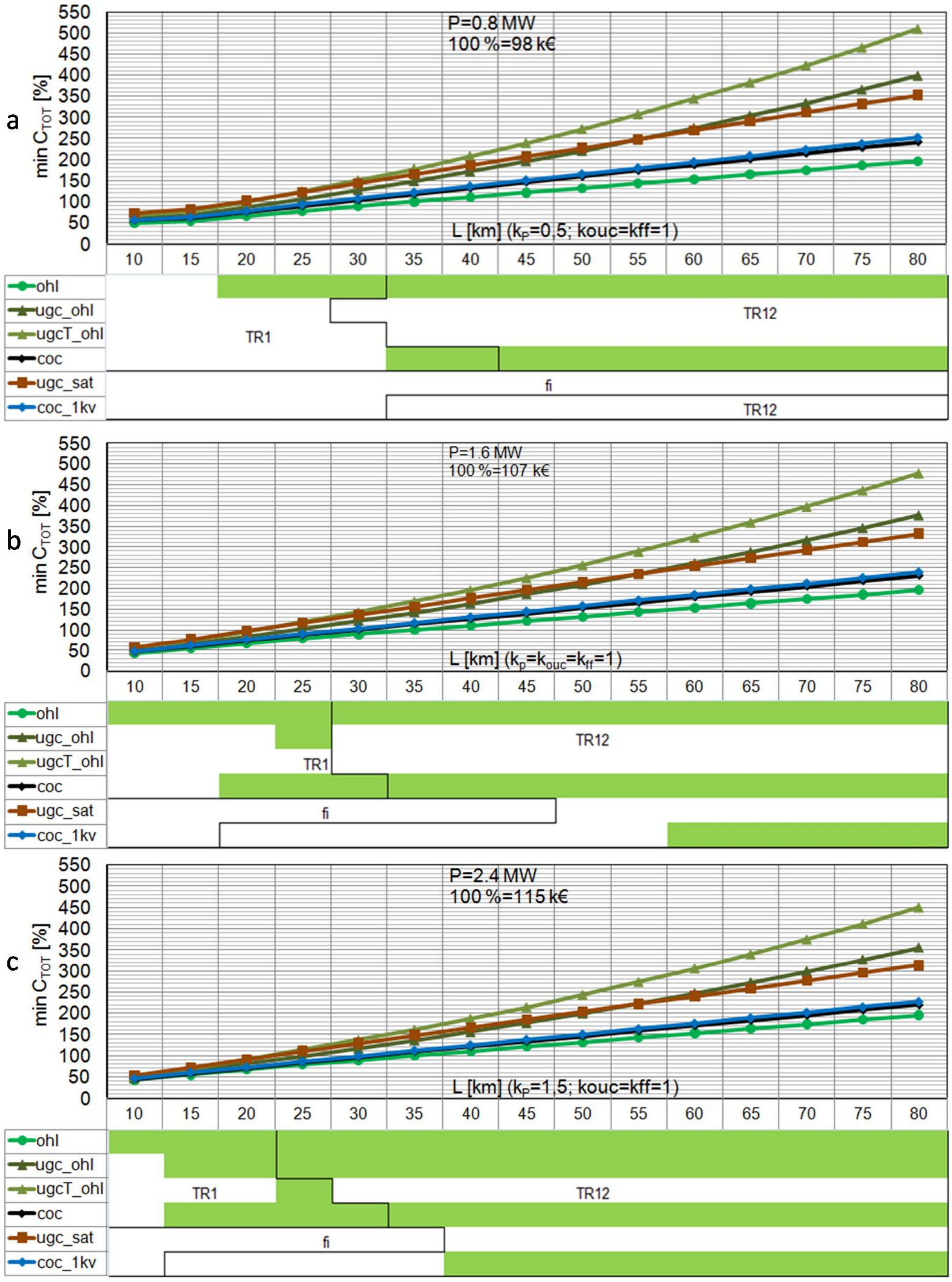


Figure 55. The impact of feeder total line length and average power on the optimal neutral system and FA scheme with regard to the minimum annual total cost of the different generic feeders. The comparison level is the ohl generic feeder with the feeder total line length variation ladder 1. The feeder average power variation ladder is 0.5 (a), 1.0 (b) and 1.5 (c). The feeder neutral system/automation scheme is given by the colour and ID in the x-axis table where white indicates an isolated neutral system and green earth-fault current compensation.

5.6 Summary

The benefit/cost and incremental benefit/cost concepts are two cornerstones of optimized reliability planning. In this chapter the concepts have been used to evaluate the cost efficiency of different automation schemes applied to the designed generic model feeders and to study the influence of the automation schemes on the cost efficiency of different network investments. The aim has been to present results which can be implemented to Finnish rural/sub-urban distribution systems. The impact of loading level, outage unit cost, fault frequency and line length on the optimal neutral system and feeder automation scheme has also been demonstrated. In the following Chapter two real feeders will be studied to compare the results with the homogenous feeder and the inhomogeneous distribution system.

6 A PRACTICAL CASE STUDY

Two rural feeders of a Finnish distribution company, Vaasan Sähköverkko Oy in the coastal area of Western Finland, were studied with respect to the cost-effectiveness of remote control of line switches and line reclosing. Vaasan Sähköverkko Oy is a medium sized distribution company which distributes electricity to the town of Vaasa, Korsholm, Laihia, Vörå-Maxmo, Malax and Korsnäs and also to some parts of Närpes and Jurva, a total area of 3 050 km². In 2008 the company had 62406 customers and a turnover of 21.6 million euro. The peak power was 178 MW and the total length of the distribution lines was 5 858 km.

6.1 Technical data of the two real feeders studied

The feeders studied are connected to a primary distribution substation near Vaasa town. Feeders F1 and F2 feed the rural areas south & north respectively of the primary distribution substation. Both distribution areas are rural with a few villages located along the feeder. Technical data of the feeders are given in Table 20 (Lågland & Kauhaniemi 2009: 2). Comparing the data of the feeders studied with the average data of Finnish rural feeders shows that the studied feeders are substantially longer than the average Finnish rural feeders. The degree of cabling is also slightly higher than the rural average. The number of distribution substations per circuit length is however, very near the average of the Finnish rural distribution feeders.

Table 20. Technical data of studied reel feeders F1 and F2.

Feeder	**P** [MW]	**L** [km]	**UGC** [%]	**DSS** [1/ km]	**Number of**		
					Lateral lines	NOPs	RC line switches
F1	1.4	54.5	7.8	0.84	27	3	2
F2	1.1	68.6	6.6	0.93	37	5	4
Finnish average (FEI 2004: 3)		31.6	4.0	0.9			

In Table 21, the measured fault frequencies of the studied feeders are compared with the fault frequencies calculated with the feeder models when using average Finnish rural feeder component fault frequencies (FEI 2004). The high-speed auto-reclosing frequency of the feeders is about half of the average for Finnish rural feeders while the delayed auto-reclosing frequency of the feeders is much lower than the rural average which indicates that if the former fails often the latter too fails and the fault is registered as a permanent fault. The permanent fault frequency of both feeders is below Finnish rural average. The configuration of the feeders is represented in Figure 56.

Table 21. Annual outage statistics of the studied real feeders.

Feeder	Forestry [%]	[1/100 km, a] HSAR	DAR	Outages
F1	15	25.8	1.5	4.3
F2	20	24.0	1.5	3.7
Finnish average (FEI 2004: 3)	28	51	9.6	5.4

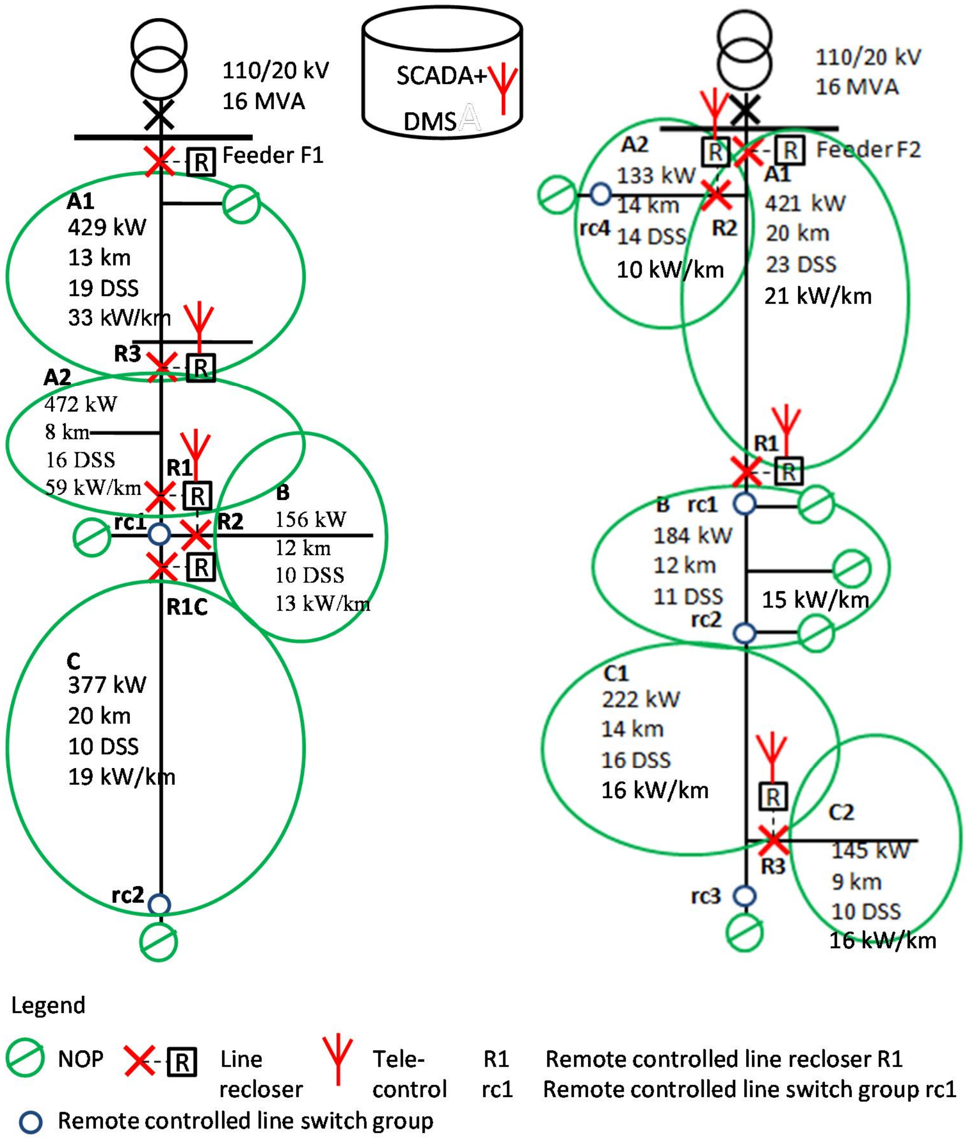


Figure 56. Circuit configuration, zone design and data of the real feeders F1 and F2.

Both feeders are typical rural feeders feeding villages and built mainly with overhead lines with short lengths of underground cabling. Feeder F2 also includes 4 km of coated overhead conductor. The average power in feeder F1 is slightly higher than in feeder F2 although feeder F2 has a longer total length. The number of backup connections (NOP) in feeder F2 is over twice that of feeder F1 and the number of remote operated line switch groups is four in feeder F2 compared to two in feeder F1.

The feeders are divided into sectionalisation zones limited by normally open points, remote operated line switches and alternative remote operated line recloser locations for the purpose of calculation (Figure 56 on the previous page). The feeder zones are further divided into main component groups representing the different load/fault sections. The FEI fault statistics report is used for internal allocation of faults and auto-reclosings (FEI 2004). Apart from four remote controlled line switch groups where feeder F2 can be connected to adjacent feeders, it can also be connected to a neighbouring primary distribution substation through a normally open recloser. The characteristics of the zones of the two feeders are given in Table 22.

Table 22. Sectionalisation zone data of feeder F1 and F2.

Feeder	**Zone** (forestry [%])	**Power**		**Line length**			**Distribution substations**
		Average [kW]	Density [kW/km]	OHL [km]	UGC [km]	COC [km]	
F1	A1 (10)	428	33	9.9	3.8		19
	A2 (30)	472	59	8.2	0.3		16
	B (10)	156	13	12.5			10
	C (10)	377	19	19.6	0.2		20
Total	4	1434		50.2	4.3		65
F2	A1 (20)	421	21	19.7	0.1		23
	A2 (20)	133	10	9,5	4.4		14
	B (25)	184	15	12,4	0.1		11
	C1 (20)	222	16	11.8		2.2	16
	C2 (20)	145	16	6.6		1.9	10
Total	5	1104		60.0	4.5	4.0	74

The unit cost of NDE and AR are specified by the Finnish Energy Market Authority. The values are corrected according the construction index to correspond to the price level in year 2010 (Table 13 on page 85).

Typical fault frequencies for rural networks are used in the calculations. Because the fault frequencies vary from feeder to feeder, the fault frequencies used are corrected so that the feeder model gives the same fault frequency as is measured according to a 3.25 year long distribution company statistics. For feeder F1 the correction factor is 1.648 and for feeder F2 1.066. This means that feeder F2 has a lower fault frequency than the average of Finnish rural feeders, while the environment of feeder F1 is very much severe than the rural average. Used fault frequencies, unit cost values, repair and switching times and auto-reclosing frequencies are presented in Appendix 7.

6.2 Calculation of the reliability indices of the real feeders

The list of symbols that are used for describing the different remote controlled substations and line reclosers are given in Table 23. Calculated *T–SAIFI* for the feeders with different automation schemes is presented in Figure 57. As can be seen from the figure the average *T–SAIFI* of the feeders corresponds to the number of permanent outages in Table 21 on page 115. *T–SAIFI* isn't influenced by remote control, while line reclosers restrict the influence of faults to the first upstream recloser and thus influence average *T–SAIFI* of the feeder. Without sectionalisation *T–SAIFI* in feeder F1 is 16 % higher than in feeder F2 although the total line length is shorter indicating that the environment in feeder F1 is more severe than in feeder F2. *T–SAIFI* in both feeders can however be improved by about a half by using line reclosers.

Table 23. Feeder automation scheme symbols used for the real feeder study. Regarding component locations see Figure 56 on page 115.

Automation	Symbol	Description
Remote controlled switches	rc12	Remote controlled line switches rc1 and rc2
	rc1–4	Remote controlled line switches rc1, rc2, rc3 and rc4
Remote controlled line recloser	R12	Remote controlled line recloser R1 and R2
	R1–3	Remote controlled line reclosers R1, R2 and R3
	R1(3)	Installation of remote controlled line recloser R1 when the feeder already includes line recloser R3

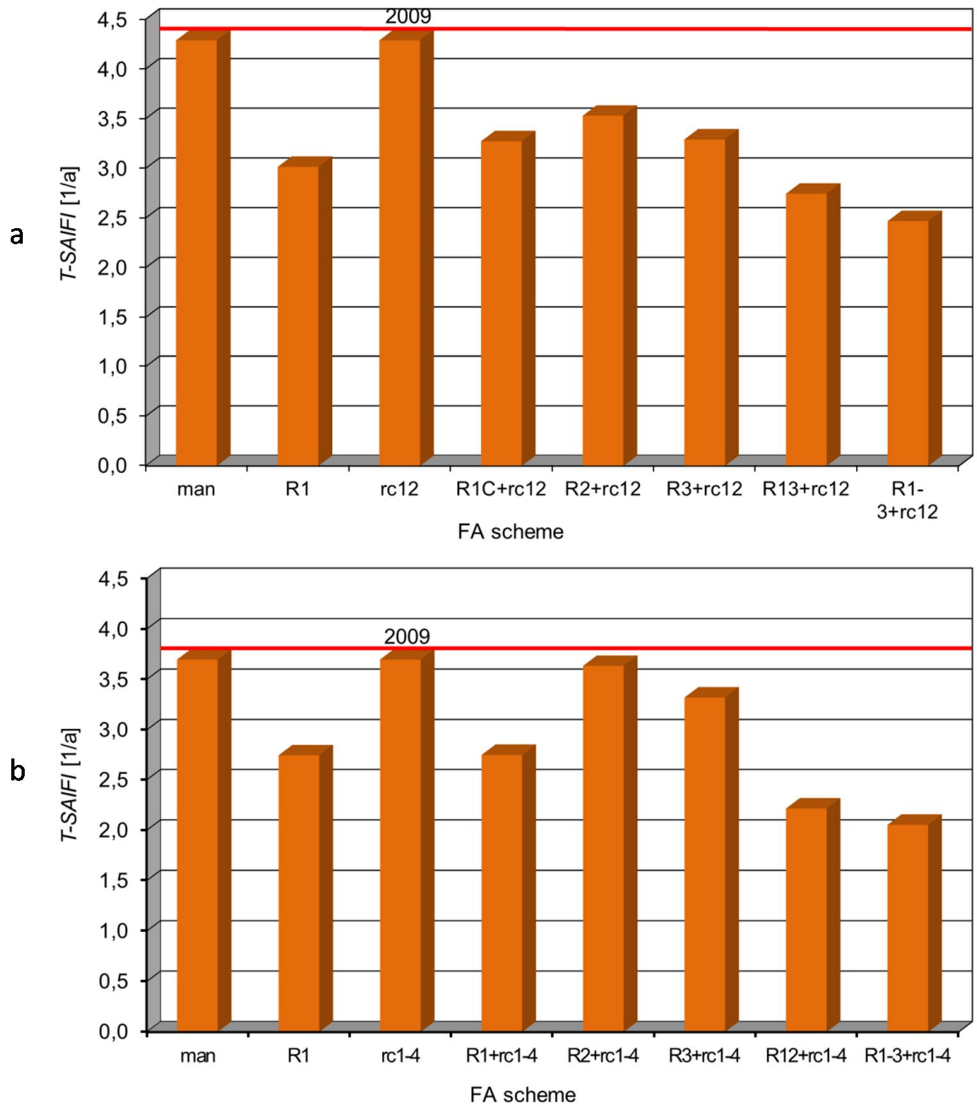


Figure 57. Calculated *T–SAIFI* of the real feeders F1 (a) and F2 (b) with different FA schemes. The performance level in year 2009 is marked with a horizontal line.

T–MAIFI reflects the frequency of momentary interruptions (≤ 3 min) that influence the total number of distribution substations of the distribution area. The calculated *T–MAIFI* of the two real feeders studied with different automation schemes is presented in Figure 58. With two line reclosers, *T–MAIFI* can be improved to about a half of its initial value without any feeder automation. For Finnish rural distribution networks the average value is about 25.5 1/ year for a 50 km long overhead line feeder with a high-speed auto-reclosing frequency of 0.51 1/year, km.

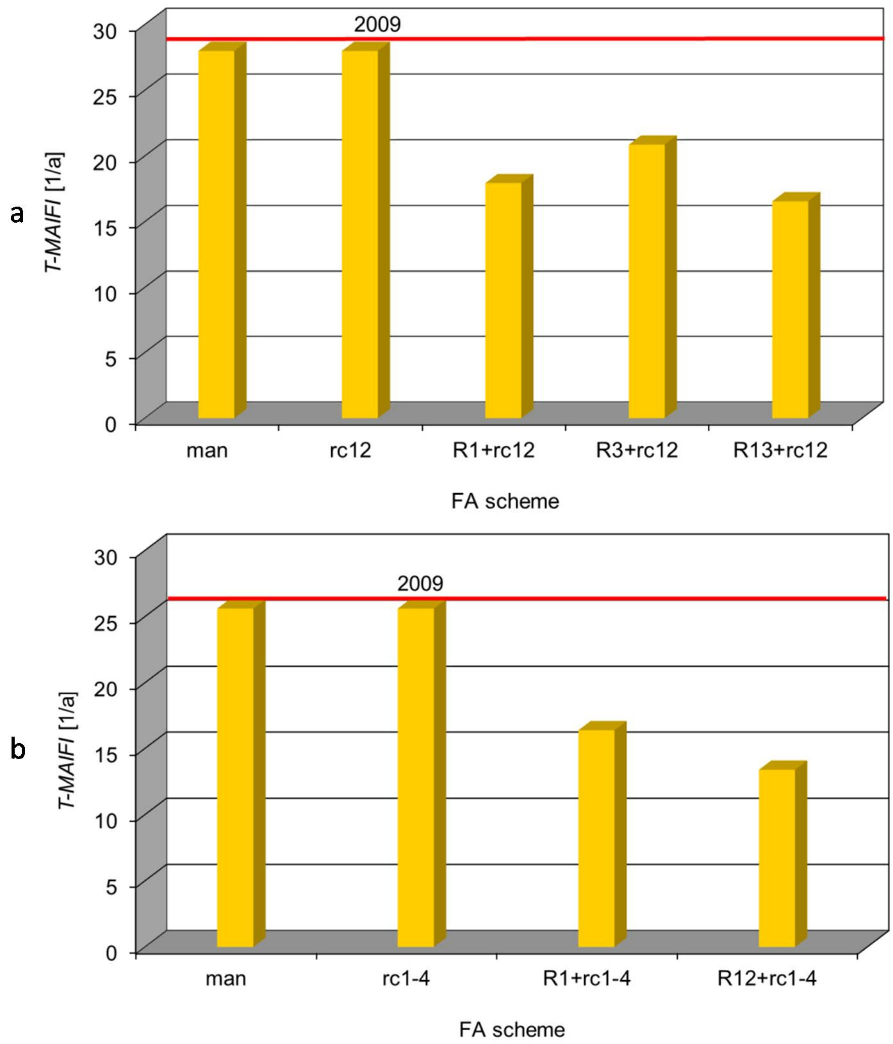


Figure 58. Calculated *T–MAIFI* of the real feeders F1 (a) and F2 (b) with different FA schemes. The performance level in year 2009 is marked with a horizontal red line.

Calculated *T–SAIDI* for the studied feeders is presented in Figure 59. The distribution company has considerably improved *T–SAIDI* with the help of remote controlled line switch groups. It has been improved from its initial value of 4.5 h/year to 2.1 h/year in the beginning of 2009 in feeder F1 while the corresponding values of feeder F2 are 3.9 h/year and 1.8 h/year. Thus *T–SAIDI* has been reduced to more than a half of its initial value in both feeders. As can be seen from the figure, it is still possible to improve *T–SAIDI* with the help of one or more remote controlled line reclosers. It is found that the use of remote control improves feeder average *T–SAIDI* but using remote controlled line reclosers, both *T–SAIFI*, *T–MAIFI* and *T–SAIDI* can be improved at the same time.

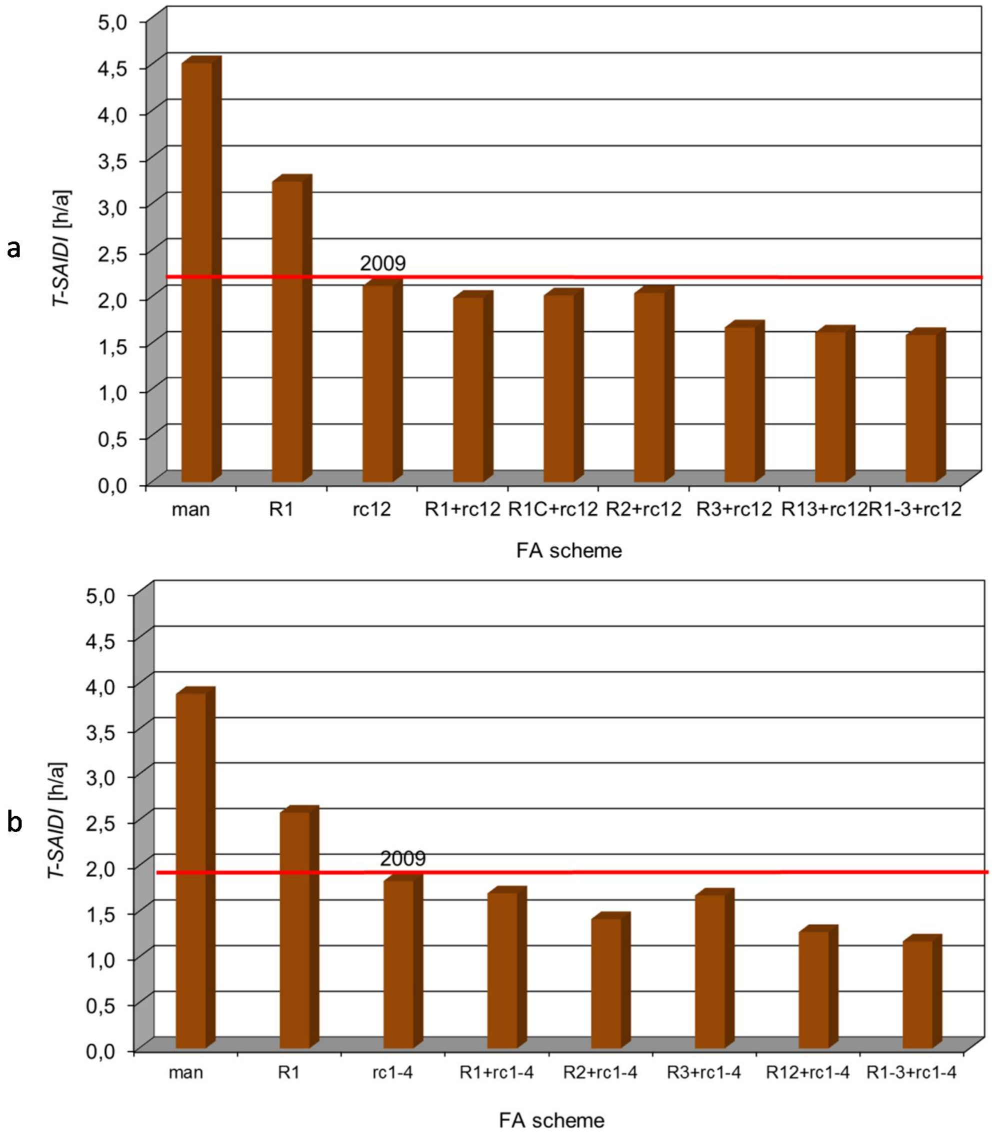


Figure 59. Calculated *T–SAIDI* of the real feeders F1 (a) and F2 (b) with different FA schemes. The performance level in year 2009 is marked with a red horizontal line.

6.3 The annual total outage cost of the real feeders

Costs related to outages are the cost of non-delivered energy and the cost of auto-reclosing. The costs are calculated for different feeder automation schemes (Figure 60). Due to a higher fault frequency and a higher average power the total outage cost of feeder F1 is considerably higher than of feeder F2. With the automation solutions in use in year 2009 the annual total outage cost of feeder F1 is 82 k€ while the corresponding cost of feeder F2 is 55 k€. The total outage cost reduction of about one third has mainly been achieved by using remote control of line switch groups. As can be seen there is still a reduction potential of about 40 % by using a few remote controlled line reclosers and thus reducing both the cost of NDE and AR.

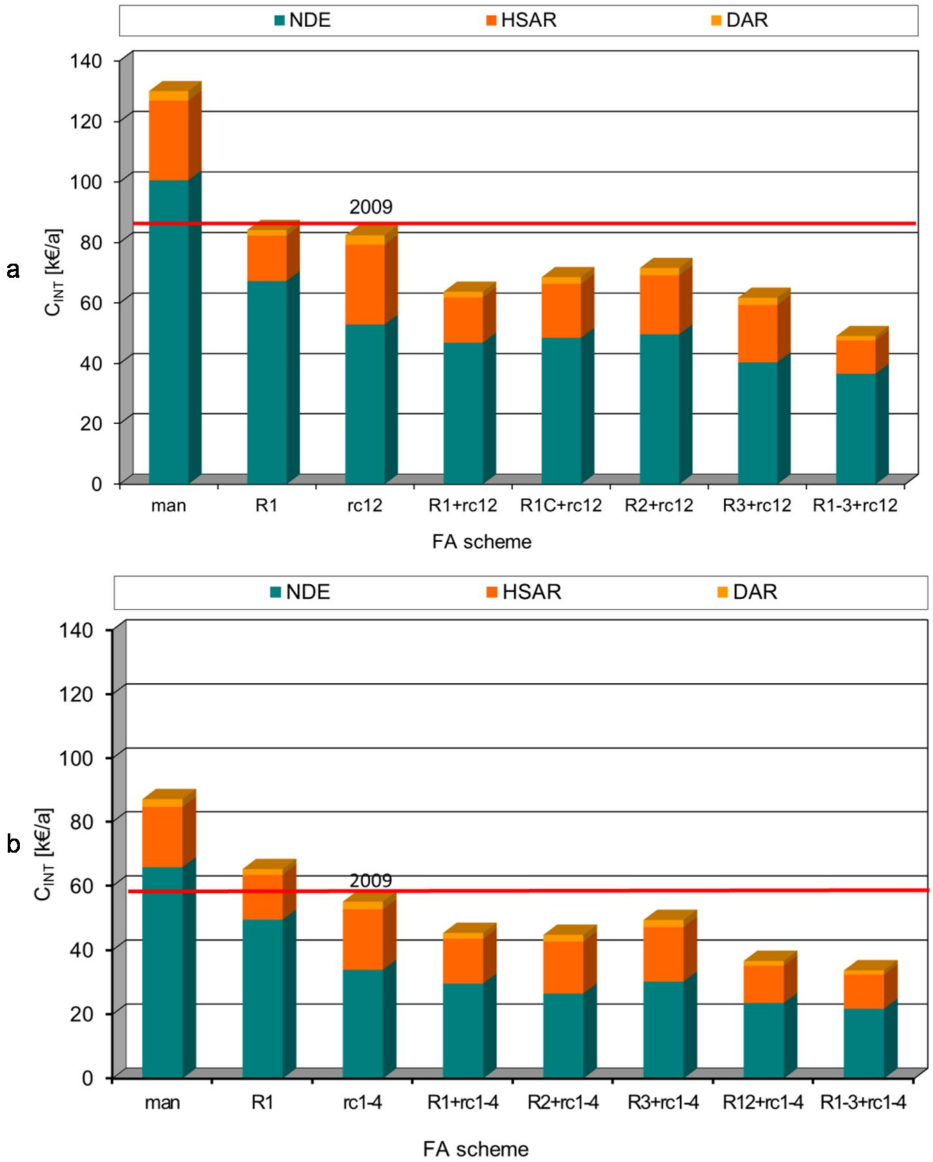


Figure 60. The annual total outage cost of feeders F1 (a) and F2 (b) with different FA schemes. The annual total outage cost level in year 2009 is marked with a red horizontal line.

6.4 The economic benefit of feeder automation

The annual economic benefit of different feeder automation schemes compared to the basic feeder without any automation is calculated. Thus the annual saving of the total outage cost of both investments that have been done and the annual saving potential of different remote controlled line recloser schemes can be calculated. The annual total outage cost saving of automation scheme *i* is:

$$B_i = \left[\left(C_{NDE\,0} - C_{NDE\,i} \right) + \left(\mathrm{C}_{\mathrm{AR}\,0} - \mathrm{C}_{\mathrm{AR}\,i} \right) \right], \tag{62}$$

where

C_{NDE0} = the cost of NDE of the basic feeder without automation
C_{NDEi} = the cost of NDE of the feeder with automation scheme *i*
C_{AR0} = the cost of AR of the basic feeder without automation
C_{ARi} = the cost of AR of the feeder with automation scheme *i*

The annual total outage cost saving of the two feeders is given in Figure 61. The annual saving with remote control of line switch groups is 47 k€ in feeder F1 and 32 k€ in feeder F2. A further annual saving is still possible by using remote operated line reclosers. The annual cost saving is dependent upon the number and location of the reclosers.

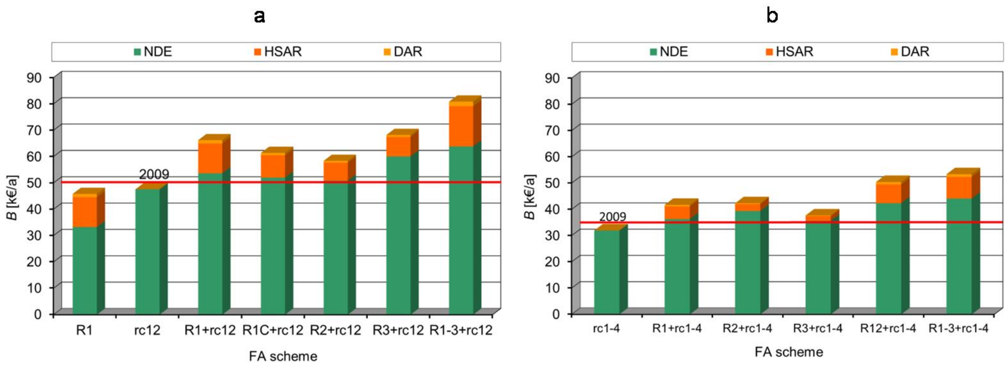


Figure 61. The annual total outage cost saving with different FA schemes of feeders F1 (a) and F2 (b) when compared to the basic feeder with no FA scheme. The annual total outage cost saving level in year 2009 is marked with a horizontal line.

6.5 The payback time of feeder automation investments

The payback time of different remote controlled line recloser schemes are calculated with regard to the saving that can be achieved in the annual total outage cost compared to the total outage cost with the automation schemes used in year 2009. In Figure 62 the payback time of the first installed remote controlled line recloser in the feeders is presented. In feeder F1 the payback time of the calculated first line recloser is 1.2–2.3 years. The payback time of the calculated first line recloser is 2.4–4.4 years in feeder F2. The most cost effective line reclosers are R3 and R1 in feeder F1 and R2 and R1 in feeder F2.

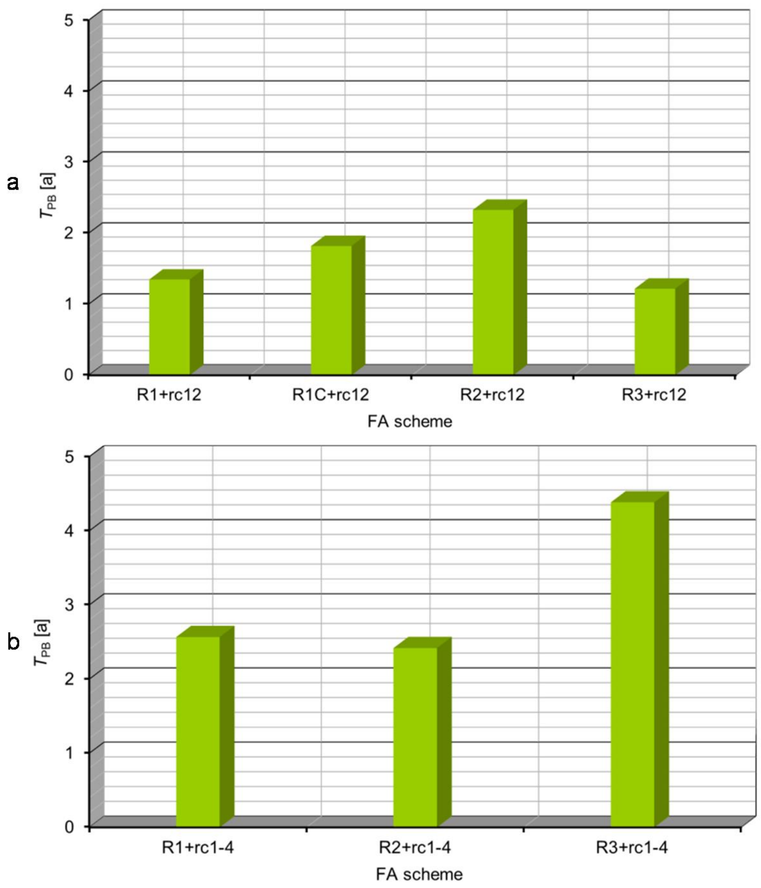


Figure 62. The payback time of the first installed remote controlled line recloser in feeders F1 (a) and F2 (b). The costs are compared to the FA level in year 2009 with two (F1) and four (F2) remote controlled line switch groups.

6.6 Automation of the T-branch in feeder F1

About halfway of its length, feeder F1 is divided into two branches forming a T-branch which is significant regarding both line length and average power (Figure 63). Because the payback time of R3 was the shortest of the studied individual alternative line reclosers it is assumed that it is installed first. According to the additional calculations the second line recloser to be added to the feeder is R1 with a payback time of 2.6 years. Adding a third line recloser R2 is not so profitable because its payback time is 8 years.

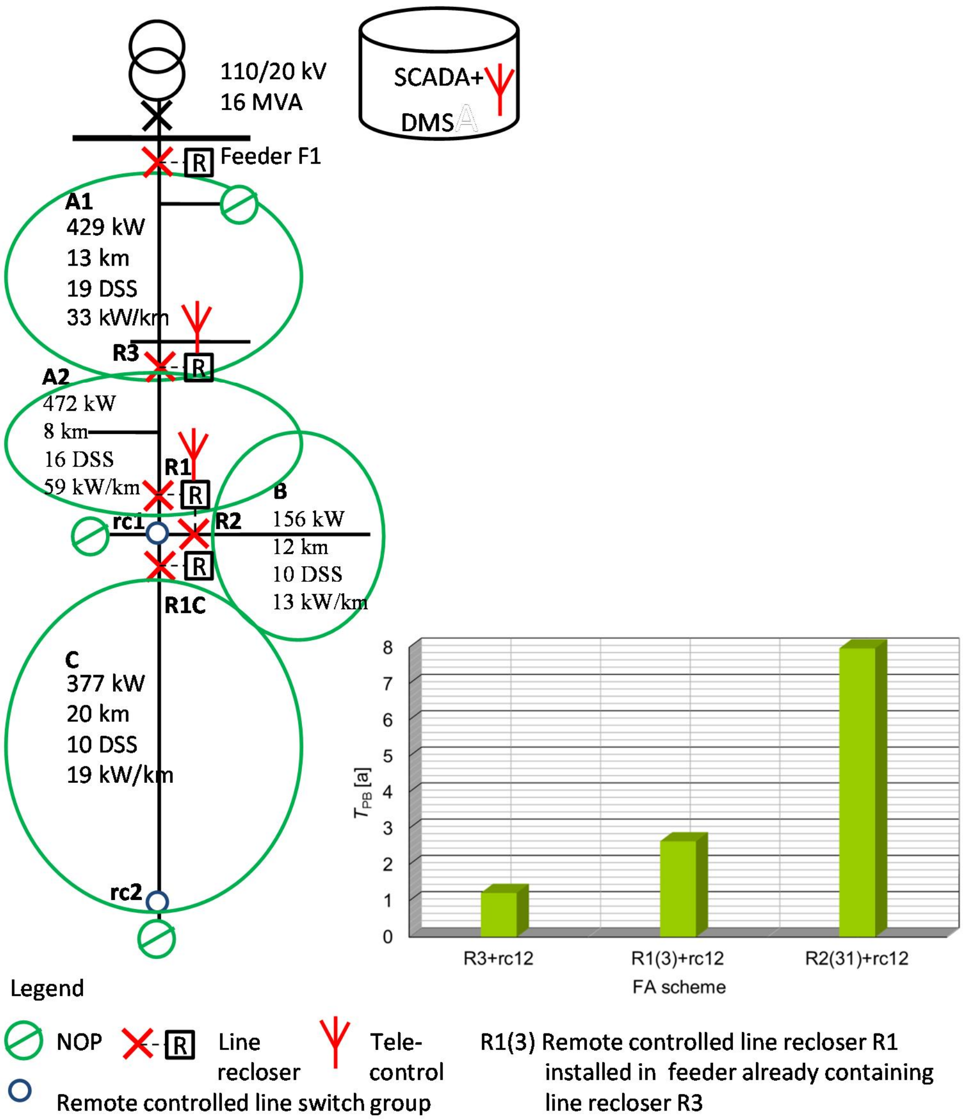


Figure 63. Alternative FA schemes of the T-branch in feeder F1 (left) and payback time of the first, second and third remote controlled line recloser (right).

The profitability of each single investment depends on the annual cost saving and the payback time of the investment, which are presented in Table 24. Depending on the higher fault rate and average power the profitability of remote controlled line recloser investments are higher in feeder F1 than in feeder F2.

The most cost-effective line reclosers are R3 and R1 upstream of the T-branch in feeder F1. The payback time of these line reclosers is 1.2 and 1.4 years respectively. The highest annual cost saving of a line recloser in feeder F1 is about twice the highest annual cost saving of a recloser in feeder F2. According to the results, line reclosing is especially effective in long overhead line feeders with a high average power and little or no remote control.

Table 24. The cost-efficiency of the line reclosers when compared to the situation in year 2009 with remote control of line switch groups. R1(3) = Installing of recloser R1 in the feeder already containing recloser R3.

Feeder	**Recloser**	**Annual saving** [k€]	**Payback time** [a]
F1	**First**		
	R3	20.6	1.2
	R1	18.6	1.4
	R2	10.8	2.3
	R1C	13.8	1.8
	Second		
	R1(3)	9.5	2.6
	Third		
	R2(31)	3.2	8.0
F2	**First**		
	R1	8.8	2.6
	R2	8.9	2.4
	R3	4.7	4.4

6.7 Summary

The second supervisory period that took effect from the beginning of 2008 has introduced new elements into the investments on the reliability of electricity distribution. When the reliability goals set by the EMA are exceeded the distribution company gets a price bonus and vice versa. This enables the distribution companies to calculate in advance the cost efficiency of alternative reliability improving investments. Here the cost-efficiency of using remote controlled line reclosers in two real feeders has been studied. The annual total outage cost is calculated for the basic feeders without feeder automation, with the feeder automation scheme used in year 2009, usually remote controlled line switch groups, and also with different remote controlled line recloser schemes. Thus the annual economic benefit, benefit/cost and payback time of different automation scheme investments have been calculated.

According to the results the distribution company Vaasan Sähköverkko Oy has improved *T–SAIDI* of the two feeders to about the half of the value of the original feeders and reduced the outage related cost with about a third compared to the original feeders with no remote control. What can then be achieved by the use of remote controlled line reclosers? According to the calculations, the payback time of the first remote controlled line recloser in feeder F1, depending on the location, is 1.2–2.3 years. In feeder F2, the payback time of the first alternative line recloser varies from 2.4 to 4.4 years. In these two studied feeders the saving potential obtained by using remote controlled line reclosers is of the same order as the saving already achieved with remote control of line switch groups or another third of the annual total outage cost. As a result of these studies Vaasan Sähköverkko Oy has now a total of 17 line reclosers of which most are remote controlled. A GPRS modem handles the communication between the primary distribution substation and the line recloser. In this way all the three electricity distribution reliability indices *T–SAIFI*, *T–MAIFI* and *T–SAIDI* are improved, because line reclosing limits the influence of a fault to the nearest upstream recloser.

Regarding the location of line reclosers the starting-point is the actual feeder configuration including present remote controlled line switches/line switch groups and normally open points. If the network is homogenous, that is both load density and configuration are uniform, the line reclosers can be located evenly along the feeder according to the even distance principle. In case the network is not homogenous, natural and cost-effective locations of line reclosers are downstream of load centres and upstream of long branches.

The cost-effective number of line reclosers also depends on the extent of present remote controlled line switches. In this aspect feeder F2 is not typical although it is cost effective to install one line recloser also into this feeder. In feeder F1 with no remote control at present it is cost-effective to install a line recloser even if the fault frequency of the feeder is only a half of the actual fault frequency. A rough estimate of the potential number of cost-effective line reclosers for the studied distribution company would be about 15, the total number of feeders being 95. This means that about 16 % of the feeders of this distribution company have cost-effective locations for remote-controlled line reclosers. This estimate is made according to the results of the calculations and the fault frequency statistics so it is only an estimate but still indicative.

7 SUMMARY AND EVALUATION OF THE RESULTS AND RESEARCH METHODS

7.1 Interrelation of phenomena, costs and reliability indices

The effects of different electricity distribution reliability improving methods have been studied with the help of the medium-voltage system level reliability indices *T–SAIFI*, *T–MAIFI* and *T–SAIDI* and different economic indices. The reliability improving economic effects are compared by calculating the annual total outage cost, the annual investment cost and the annual total cost. The cost-efficiency of reliability enhancing investments is measured by means of the following: the annual cost saving or benefit, benefit/cost, incremental benefit/cost and the pay-back time. The results are presented for the rural homogenous distribution system, the generic model inhomogeneous distribution systems and two real distribution feeders. *T–SAIFI* measures the annual average frequency of permanent faults while *T–MAIFI* measures the annual average frequency of temporary faults related to the annual cost of auto-reclosing. *T–SAIDI* measures the annual average interruption time of permanent faults related to the cost of non-delivered energy (Figure 64). Thus, none of the single reliability indices measures all the economic effects related to electricity distribution reliability. The total outage cost is therefore a good measure of the effects of interruptions as it measures the annual average economic loss of both permanent and temporary interruptions on a medium-voltage system based level. The unit cost series of the new regulation model is therefore a better measure of the efficiency of investment strategies than using only reliability indices.

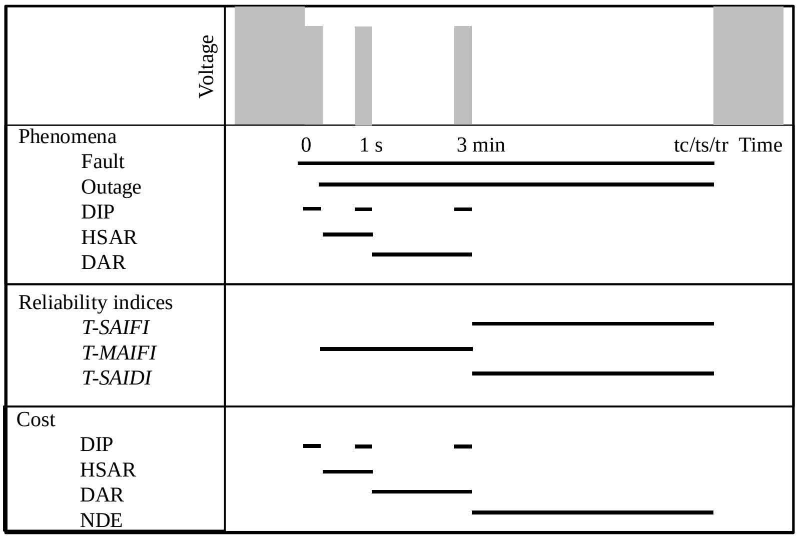


Figure 64. Phenomena, reliability indices and costs associated with a fault event.

Forest maintenance, over-voltage protection and remote control of line switch groups have been the main methods of increasing quality of supply in Finland. Now there is a trend in earth-fault current compensation of medium-voltage networks. It has been found out that modern line reclosers with an integrated remote control and protection function are very cost-effective as they influence all the three electricity distribution quality indices. This is illustrated in Figure 65.

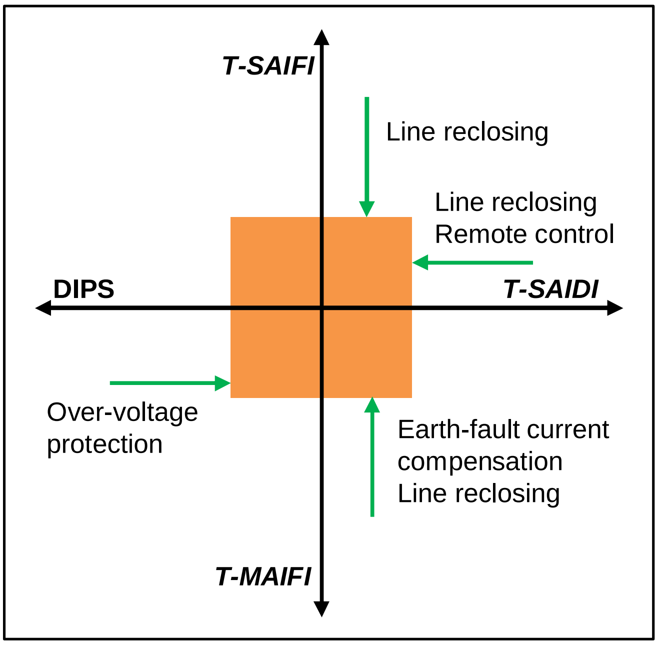


Figure 65. Effective methods of improving the electricity distribution quality and reliability.

7.2 Summary of the results

7.2.1 New distribution systems

The main target when building new sub-urban/rural distribution systems is to minimize the annual total cost of the distribution system. Also the reliability of the distribution system, measured by the annual total outage cost and the reliability indices, is important. The stressing of the different meters differs from distribution company to company. In Figure 66 a the average values of these meters of the different generic feeders are presented as percentage values where 100 % corresponds to the performance of the generic overhead line distribution system (ohl) with no feeder automation. For comparison the generic overhead line distribution system with a remote controlled line switch group is included (ohl_rc), which may represent the average Finnish rural/sub-urban neutral isolated distribution system. Already with the neutral isolated distribution system and remote controlled line switches the annual total cost of the distribution system has been reduced with approximately 10 % and the annual total outage cost with about 30 % compared to the distribution system with no feeder automation. Regarding the reliability indices the results confirm that *T–SAIDI* has been improved by almost 60 % while *T–SAIFI* and *T–MAIFI* have not been improved by remote control of line switches. Using earth-fault current compensation and remote controlled line reclosers a considerable further reduction of the annual total cost and annual total outage cost as well as a moderate improvement of the reliability indices can be achieved. On the other hand under-ground cabling increases the annual total cost but considerable reduces the annual total outage cost and improves the reliability indices. The coated overhead conductor and the 1000 V distribution system seem to have good performance on all the meters. Thus it is no wonder why earth-fault current compensation, the 1000 V distribution system, the coated overhead conductor line and line reclosing are in the area of interest among the Finnish distribution companies. How does then the digitalization of the society impact the qualities of the different distribution systems? This is illustrated in Figure 66 b where the outage unit cost level of auto-reclosing is doubled. The relative cost-efficiency of all the studied generic feeders is improved compared to the present distribution system (ohl_rc) as earth-fault current compensation and more complicated feeder automation schemes become more cost-effective.

The selection of an electricity distribution system is a trade-off between total economy, reliability and weather resistance. The lowest annual total cost is found in an overhead line distribution network with earth-fault current compensation and remote controlled line reclosers. Coated overhead line networks, 1000 V distribution systems and satellite distribution systems have the lowest annual total outage cost and best electricity distribution reliability. The best *T–SAIDI* is achieved with the use of coated overhead conductor line, the 1000 V distribution system and remote controlled line reclosers. Only totally underground cabled distribution systems are weather proof.

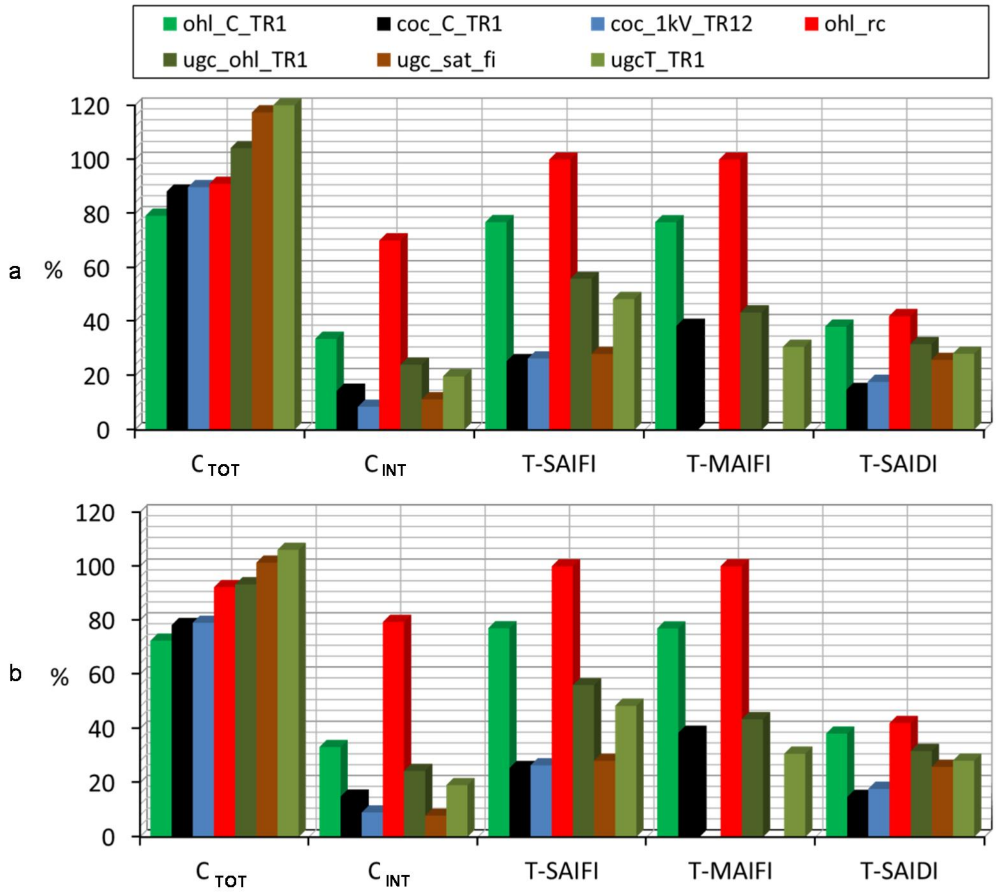


Figure 66. The percentage average performance of different indices of the generic feeders when compared to the ohl generic feeder with no FA. For comparison the generic overhead line feeder with a remote controlled line switch group is included. The implemented automation scheme is given in the ID of the generic feeder where C indicates earth-fault current compensation. Normal outage unit cost level (a) and doubled AR outage unit cost level (b).

7.2.2 Existing distribution systems

Feeder type and implemented feeder automation scheme determine the performance of existing distribution systems. If reliability improvement investments are needed available cost-effective investment alternatives can be found out using Figures 51–53 on pages 103–105. As the effectiveness of the investment depends on the total outage cost reduction capability and the payback time of the investment an index for the different reliability improving investment alternatives is created. The index is calculated by dividing the annual percentage total outage cost reduction of the investment alternative with the payback time of the investment. In Figure 67–68 the results are summarised with the help of the index. As a minimum demand of the value of the index 10 %/a is selected which corresponds to a 10 % annual total outage cost reduction when the payback time of the investment is one year and a 50 % annual total outage cost reduction when the payback time of the investment is five years. In the following is a short summary of the conclusions that can be drawn from the results.

The number and type of available cost-effective reliability improving investments is dependent on the existing network environment, network type, system neutral, implemented feeder automation scheme and homogeneousness of the distribution system. In principle the most cost-effective investment available should be chosen but the needs vary between distribution companies as well as within distribution a company. Furthermore priority of different demands changes over time. In recent years also the regulation system has begun to influence investments towards more reliability improving investments. When evaluating the results it is good to remember that the index corresponds to an average power of 1.6 MW and that it is approximately directly proportional to the feeder average power. The calculated values are minimum values because the generic distribution is optimised, e.g. with regard to the supply restoration system which always isn’t the case in real distribution systems. As earth-fault current compensation and remote control of line switch groups has been a trend among the Finnish distribution companies also these are included as a comparison level.

In overhead line distribution systems with an isolated neutral and no present feeder automation all the studied investment alternatives are available (Figure 67 a). As the cabling level increases the efficiency of all the alternatives decreases measured with the created index. This means also that when increasing cabling the cost-effectiveness of already made investments decreases. Outstanding alternatives are fault indication and the use of remote controlled line reclosers. The strength of the former is very short payback times and the latter very high annual total outage cost reduction capability. This is the situation as studied from the present point of view.

As mentioned, remote control of line switch groups is quite frequently used in Finnish overhead line networks. Figure 67 b shows that available effective investment alternatives then are the use of remote controlled line reclosers and earth-fault current compensation. In the generic distribution system fault indication seems no more cost-effective.

In overhead line networks with earth-fault current compensation without feeder automation available investment alternatives are fault indication, remote control of line reclosers and switches (Figure 68 a). Regardless of increasing cabling fault indication and line reclosing are effective investments in improving electricity distribution reliability. After implementation of remote controlled line switches line reclosing remains the only effective reliability improving investment alternative (Figure 68 b). The payback time of a remote controlled line recloser is for the four first generic feeders 2.0–4.4 years.

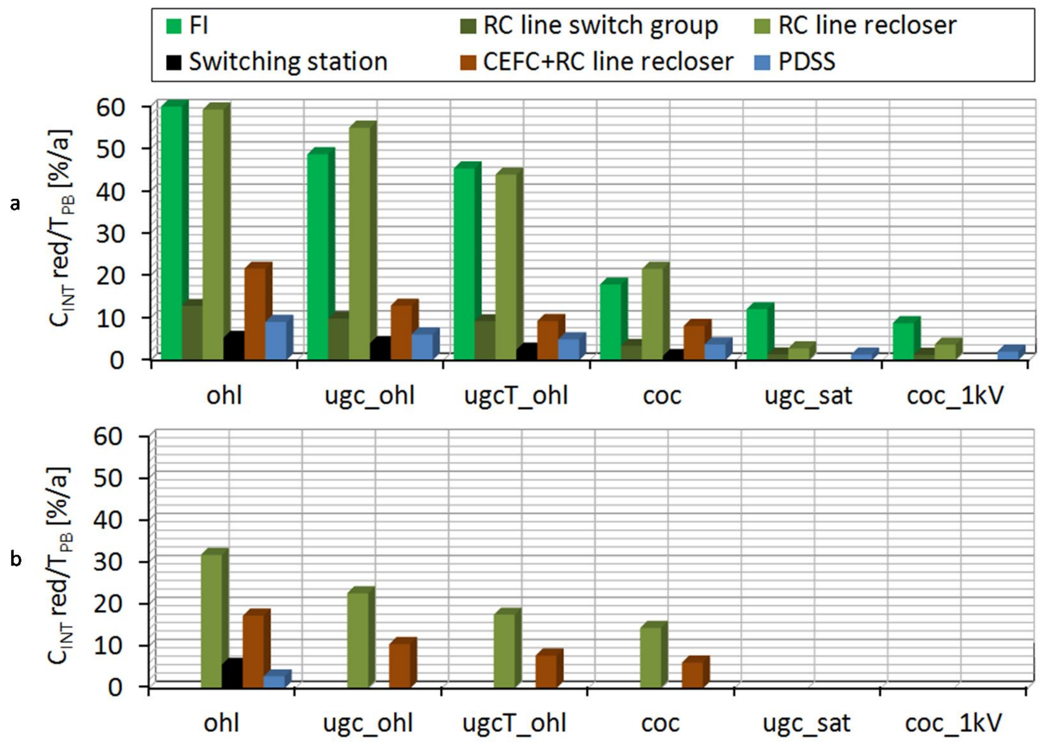


Figure 67. Suitability of the different studied investment alternatives of the different generic model networks in a neutral isolated distribution system. Comparison level is a distribution system with no FA (a) and distribution system with a remote controlled line switch group (b).

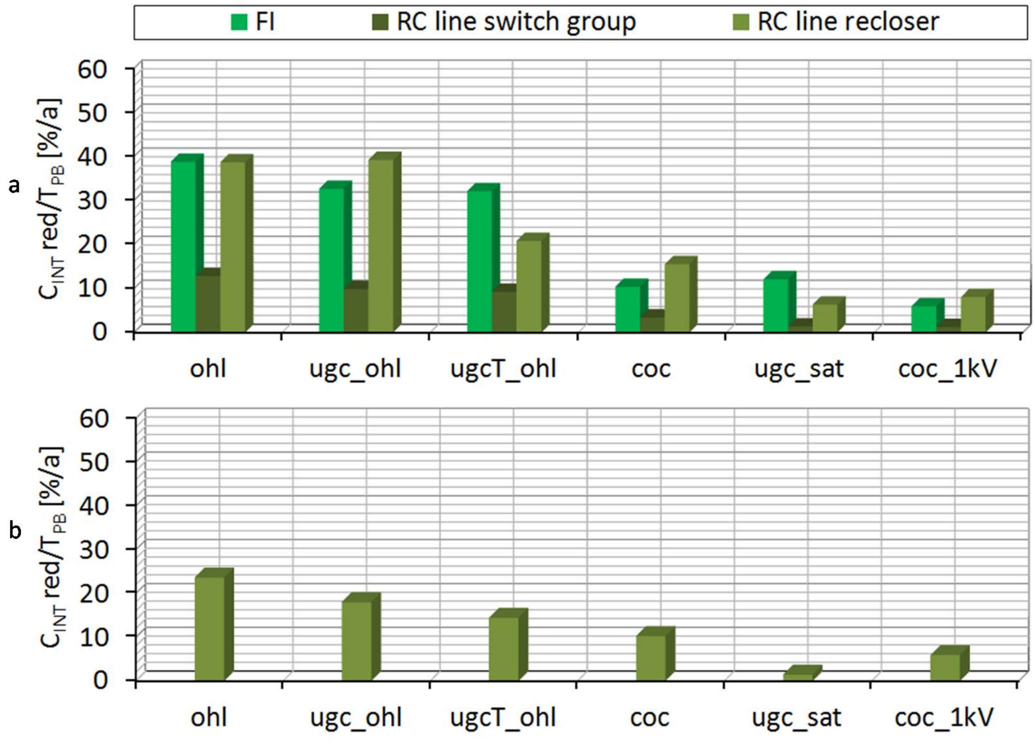


Figure 68. Suitability of the different studied investment alternatives of the different generic model networks in an earth-fault current compensated distribution system. The comparison level is a distribution system with no FA (a) and a distribution system with a remote controlled line switch group (b).

7.3 Sensitivity analysis

This entire work is a sensitivity study since the electricity distribution reliability is studied with regard to the impact of many different properties the main property being automation. Feeder automation is expected to increase and thus it is very important to know how it influences the other optional available investment strategies. Line type influence can be seen by comparing the different generic feeders to each other.

In Table 25, the properties of the generic feeders under study here are compared to the studied real feeders and average Finnish rural and urban feeders. As can be seen the inhomogeneous generic feeders with applied automation schemes represent very well the rural feeders with respect to the annual total outage cost per unit length.

Table 25. Comparison of the generic model distribution systems and real feeders studied with average Finnish rural distribution systems.

Feeder property	**Generic distribution systems**		**Finnish distribution systems**	
	Homo-geneous	Inhomoge-neous	Studied real feeders	Finnish aver-age (FEI 2004)
Line length [km]	30–100	25.7, 26.4[1]	54.5, 68.6	31.6
Forestry [%]	43	33	15, 20	43
Underground cabling [%]	0	0, 35[1], 57[1], 100	6.6, 7.8	4.0
Average power [MW]	1.0	1.6	1.1, 1.4	
Annual total outage cost [€/km, a]	542–1268	144–1957	515–2386	0–5000 (EMA 2007 b)

[1] Mixed line feeders

In many countries the cost of non-delivered energy has been introduced. In some countries the cost is based on power, in other countries on energy consumption and in a few countries like in Finland on both. The cost-efficiency of line reclosing is partly due to the introduction of the cost of auto-reclosing, which is the case in Finland.

7.3.1 *The impact of feeder automation on the different costs*

For the real feeder F1 the annual share of the cost of non-delivered energy and auto-reclosing varies according to the feeder automation scheme used (Figure 69). It can be seen that remote control of line switches reduces only the cost of non-delivered energy while line reclosing reduces the cost of both non-delivered energy and auto-reclosing. It can also be seen that the use of remote control to improve *T–SAIDI* in Finland has increased the share of the cost of auto-reclosing of the total outage cost in Finnish MV distribution systems. The unit cost values of interruptions used are socioeconomic values which are the cost of interruptions for the society. The question is how to allocate the benefits of reliability improvements between the distribution company, the customers and the society. For the first year of the regulatory period 2008–2011 in Finland, the regulatory body allocated half of the benefits of reliability improvements to the distribution company.

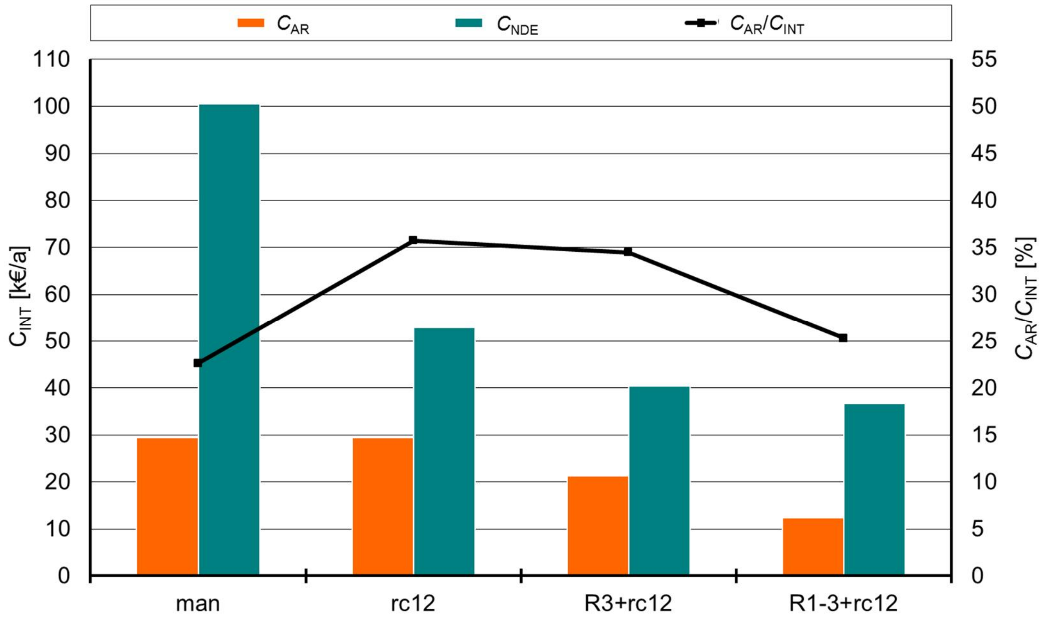


Figure 69. The annual cost of NDE and AR with different FA schemes in the real feeder F1. Acronyms: man = no FA, rc12 = remote controlled line switch group 1 and 2, R3 = remote controlled line recloser R3 and R1–3 = remote controlled line reclosers R1, R2 and R3.

7.3.2 The impact of parameter values on the reliability and economical indices

Figure 70 presents a sensitivity study of the influence of different parameters on the annual total cost (a), annual total outage cost (b), payback time (c) and *T–SAIDI* with TR1 installed (d) of the ohl generic model feeder. As can be seen load and outage unit cost correlate directly with the annual total outage cost, while fault frequency, fault clearing time and repair time have a weaker correlation. The presence of two reserve connections makes the influence of the repair time extremely low (a–c).

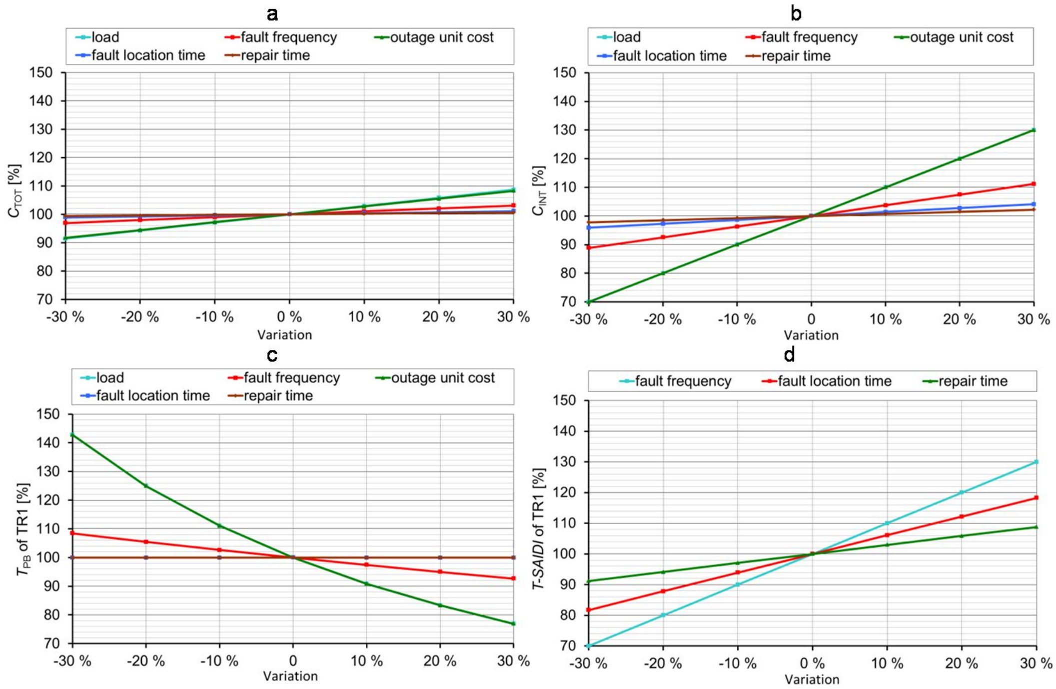
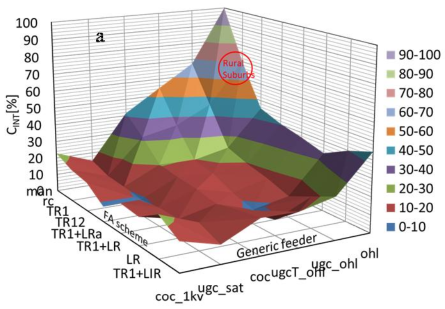
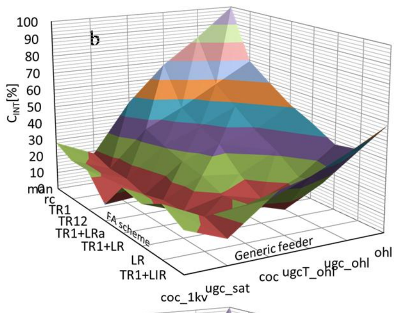


Figure 70. Sensitivity analysis of the impact of some parameters on the annual total cost (a), annual total outage cost with a remote operated line switch group (b), payback time of TR1 (c) and *T–SAIDI* with the remote controlled line recloser TR1 (d). The feeder is the ohl generic model feeder and the comparison level in (a) and (c) is a remote controlled line switch group and in (b) and (d) no FA.

7.3.3 The impact of power density variation on the cost behaviour of the of the generic distribution system

In Figure 71 the impact of the power density variation on the relative annual total outage cost of the different generic feeders with different feeder automation schemes is presented. Figure 71 a presents the relative annual total outage cost of the different generic feeders with different feeder automation schemes when the first part of the feeders have a higher power density than the second part. In Figure 71 b the situation is the opposite, while c has quite a smooth power density distribution per line length unit. The impact of the inhomogeneous power density distribution can be seen as a slightly different shape of the figures.





Property	a	b	c
Power density First/second part [kVA/km]	117/35	24/70	65/61
C_{INT} [k€/a] 100 %	49.8	46.8	52.6

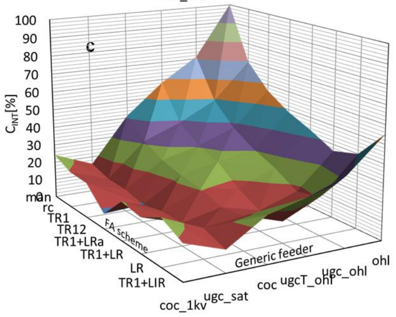


Figure 71. Impact of power density variation between the first and second part of the feeder on the relative cost of the different generic feeders and FA schemes.

7.3.4 *The impact of outage unit cost level, fault frequency and feeder average power on the optimal automation combination*

The impact of the outage unit cost level and feeder average power on the optimal neutral system and feeder automation scheme of the different generic feeders is presented in Figure 72. The relative cost-efficiency of the coc and coc_1kV generic feeders increases with increasing outage unit cost level and feeder average power. Due to an increasing annual total outage cost the relative cost-effectiveness of the ohl feeder decreases. Thus with a feeder average power of 2.4 MW and an outage unit cost level of 1.6 times of the value in the second regulatory period, the annual total cost minimum of the three mentioned generic feeders are equal.

The impact of the fault frequency level and feeder average power on the optimal neutral system and feeder automation scheme of the different generic feeders is presented in Figure 73. The fault frequency variation ladder affects both permanent and transient faults. The optimal system neutral/feeder automation scheme combinations are almost similar as for the outage unit cost level while the impact of the average power level on the relative annual total cost minimum level differs especially with an average power of 150 % (Figure 72 c).

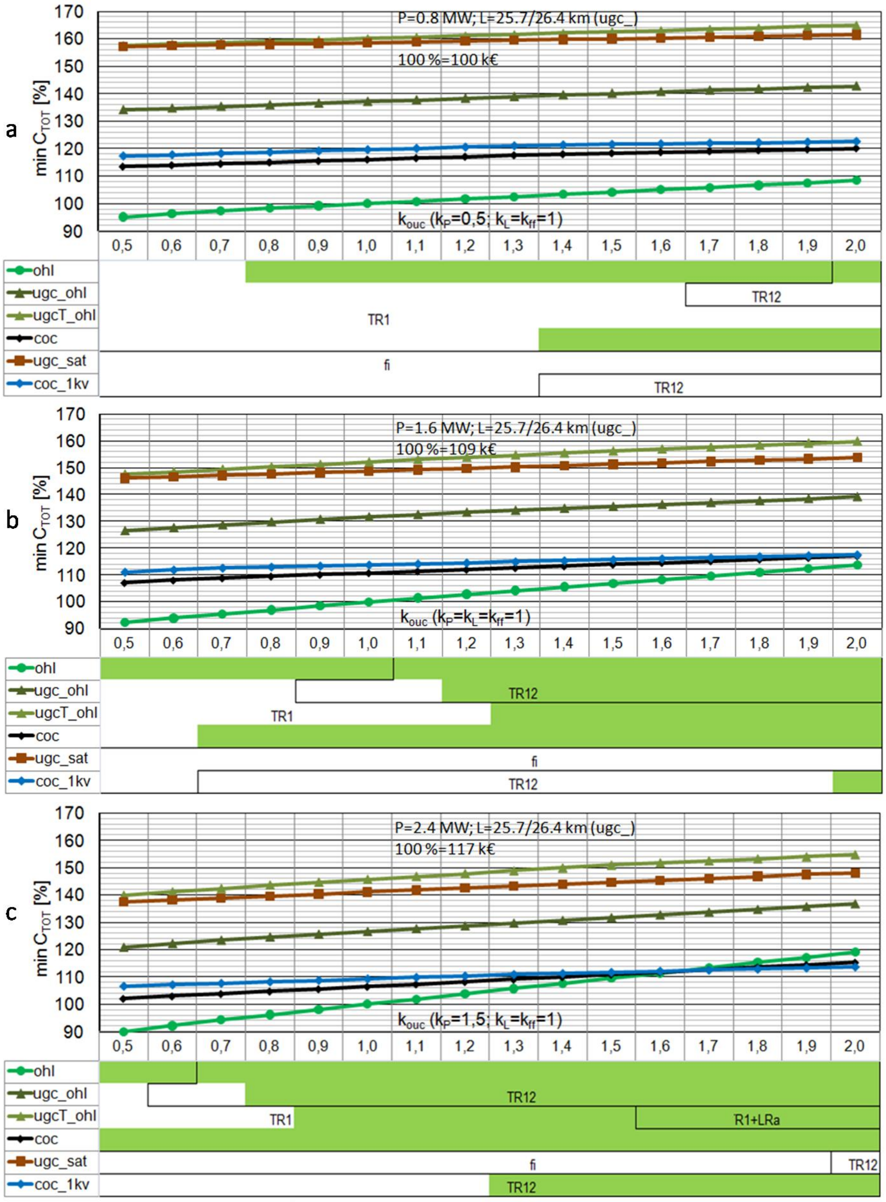


Figure 72. The impact of the outage unit cost level and feeder average power on the optimal neutral system and FA scheme with regard to the minimum annual total cost of the different generic feeders. The comparison level is the ohl generic feeder with the outage unit cost variation ladder 1. The feeder average power variation ladder is 0.5 (a), 1.0 (b) and 1.5 (c). The feeder neutral system/FA scheme is given by the colour and ID in the x-axis table where white indicates an isolated neutral system and green earth-fault current compensation.

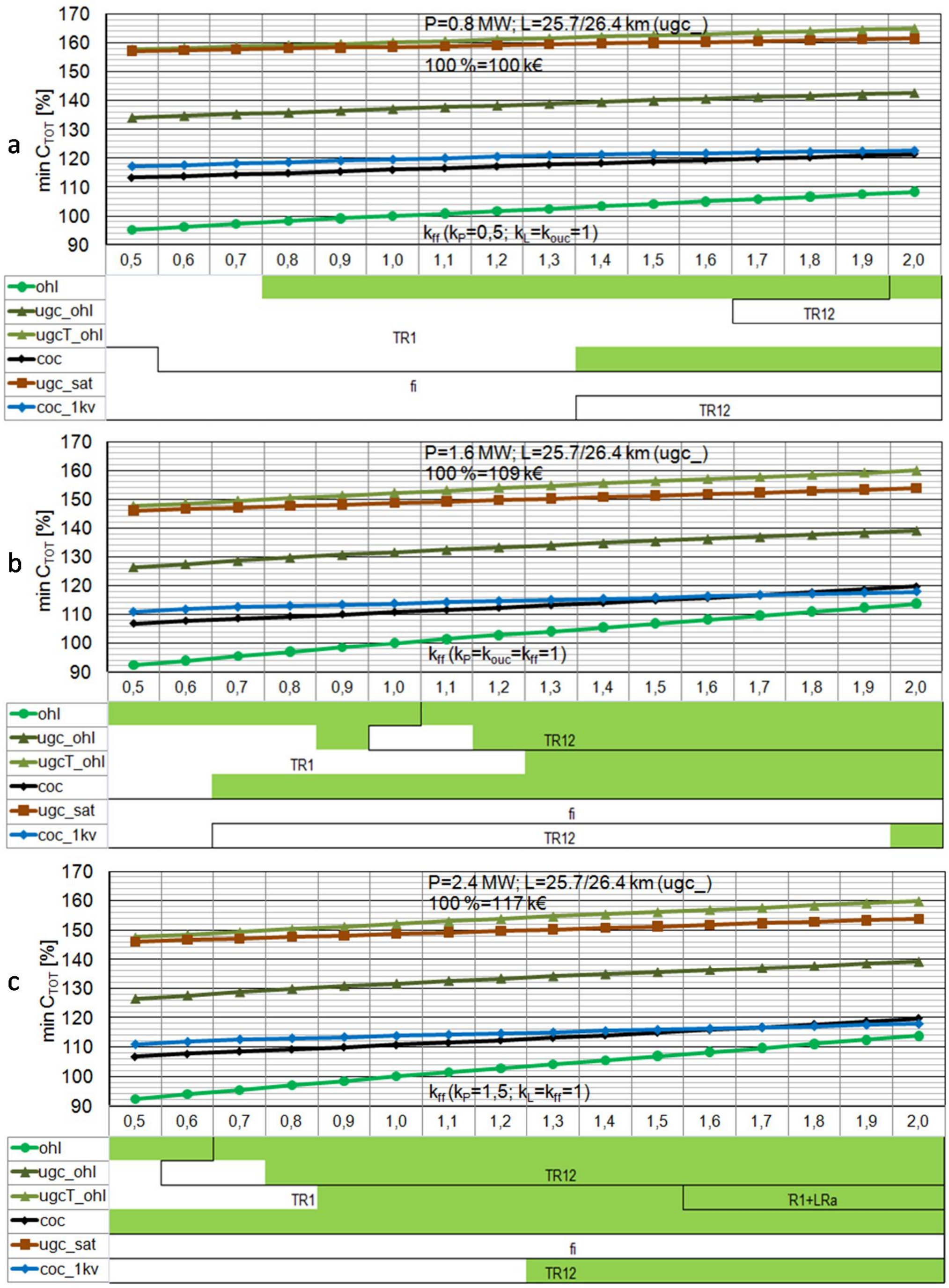


Figure 73. The impact of the fault frequency level and feeder average power on the optimal neutral system and FA scheme with regard to the minimum annual total cost of the different generic feeders. The comparison level is the ohl generic feeder with the fault frequency variation ladder 1. The feeder average power variation ladder is 0.5 (a), 1.0 (b) and 1.5 (c). The feeder neutral system/FA scheme is given by the colour and ID in the x-axis table where white indicates an isolated neutral system and green earth-fault current compensation.

7.4 The reliability of the results

In the following the reliability of the results will be studied regarding the rural homogeneous distribution system, the rural/sub-urban inhomogeneous generic distribution systems and the two real feeders studied. The reliability of the presented results is influenced by the reliability of the input data of the Finnish and the studied distribution company electricity distribution data statistics, the network modelling system and the calculation method.

Regarding the reliability of the input data of the Finnish distribution system it is most important to choose a year of data statistics which correlates to the average level of the data in question. It can be seen from Figure 74 that the long-term development of the electricity distribution reliability of Finnish medium-voltage distribution systems has been quite satisfying. The indices and data for the modelling and calculations are taken from the annual interruption statistics published by Finnish Energy Industries. Until 2004 the condition study performed by FEI was based on the distribution companies, but since 2005 a new statistics system has been introduced where the condition study is based on the feeder underground cabling level. In the first years with implementation of the new statistics system the results were a bit uncertain. Another point that complicates the choosing of a suitable year from which to get reliable average input data for modelling and calculation is the annual variation of the reliability indices due to major events. Year 2001 is excluded because then there were several major events in Finland. Because the input data should also be as fresh as possible, the optional years to be chosen are 2003 and 2007. The reliability indices, network data and fault statistics of these two years and year 2009 are compared in Appendix 12. In the first place, data for modelling and calculation are chosen from the statistics of year 2003 because they are presented in a suitable form for this study and the implementation of the old reporting system is assumed to have been more reliable than the implementation of the new one in the first years.

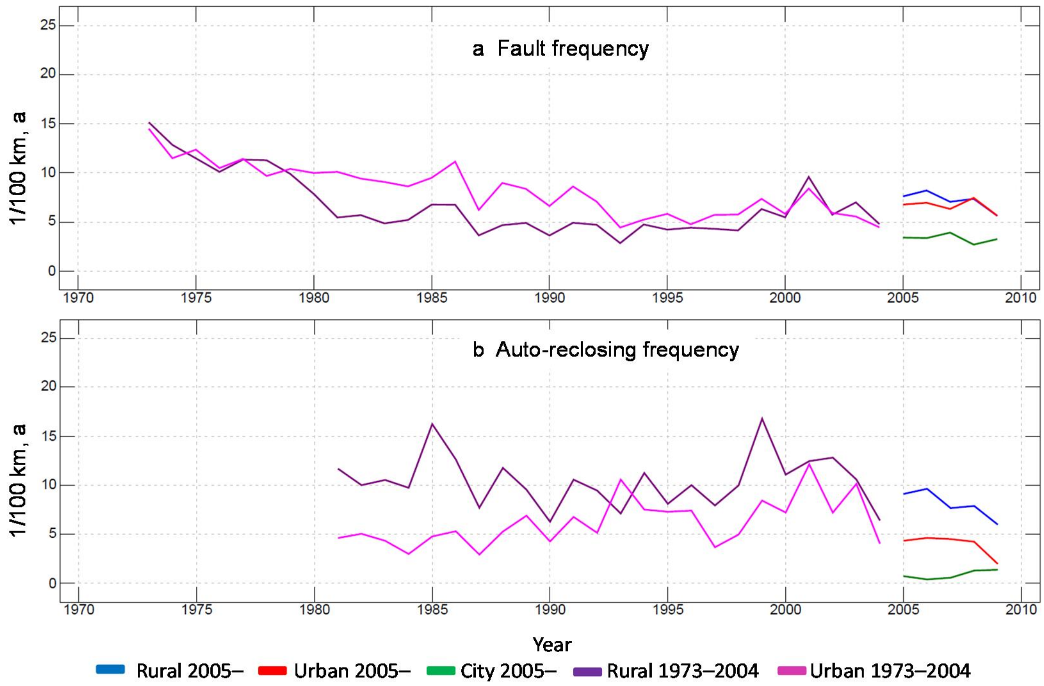


Figure 74. The long-term development of the fault and auto-reclosing frequency of Finnish distribution networks (FEI 2010: 10). A new reporting system was introduced in 2004.

The interruption duration includes fault locating, fault isolation, supply restoration and fault repair time and has a stochastic nature. The individual values of these times depend on several circumstances e.g. automation level and staff resources (Figure 5 on page 19). According to several sources the restoration time varies between 0.1 to 1.7 h (see e.g. Partanen et al. 2006: 29). According to FEI (FEI 2004: 10) the reported average outage duration on substation level depending on the fault location was 0.79 hours for faults in distribution substations and 1.01 hours for faults on the feeder line. Depending on the automation scheme the modelling of the restoration process of the studied generic feeder system gives a restoration time of 0.15–0.9 hours for the generic distribution system in the first stage of a two-stage restoration process (Appendix 11).

At first glance the used HSAR frequency 51 (1/100 km, a) seems high. The reported value in the time interval 2000–2003 in isolated rural networks was however 41.9–62.0 (1/100 km, a) with an underground cabling level of 4.3–8.6 % so the used value seems reasonable for overhead lines with an isolated neutral. The impact of earth-fault current compensation may be seen in Figure 74 b as a reduction in the auto-reclosing frequency.

Regarding the two real feeders the input data is based on statistics from only 3.25 years. As the variation of the average outage data between the different years varies only modestly the quality of the data can be considered as satisfying.

Figure 75 summarizes the impact of feeder type and automation on the annual total outage cost-reduction of the homogenous feeder, the inhomogeneous generic distribution system and the two studied real feeders. The line reclosing cost-reduction behaviour of the two studied rural feeders follows best that of the homogenous distribution system.

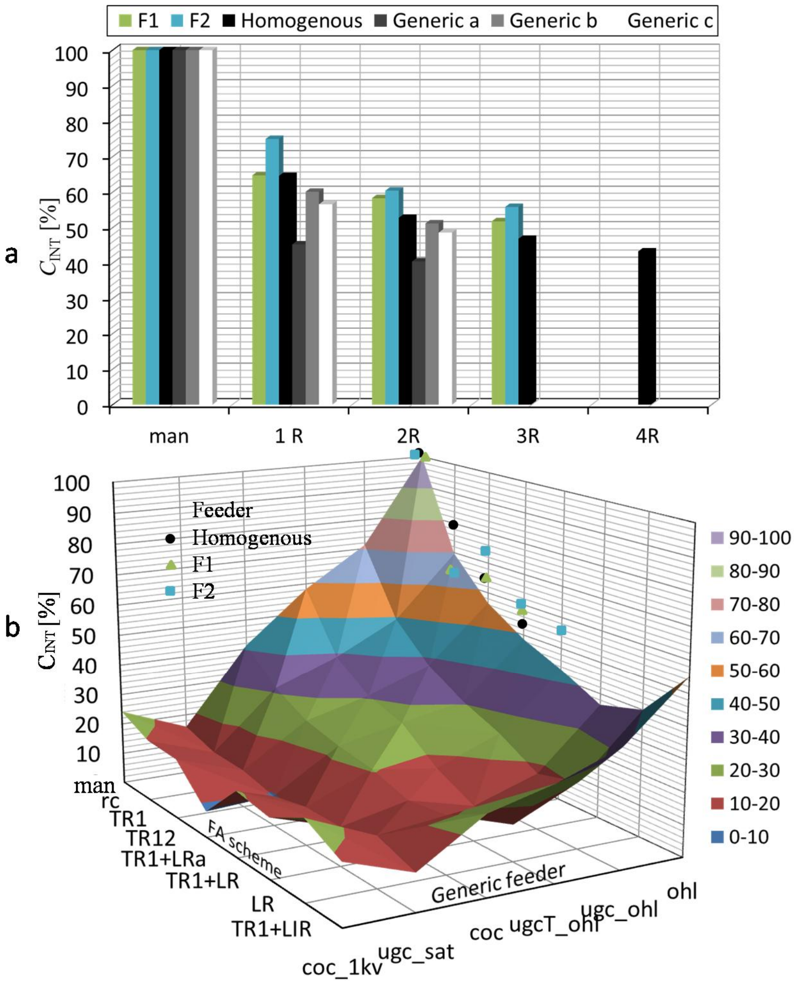


Figure 75. (a) The impact of remote controlled line reclosers in the different studied distribution systems. (b) Calculated results of the cost reduction capability of different FA schemes in the inhomogeneous generic distribution system c (Figure 71). For comparison the values of the homogenous feeder and the real feeders F1 and F2 are separately marked into the chart. Generic a, b, c in (a) see Figure 71 on page 136.

To minimise the total outage cost of real feeders generally more than one recloser is needed because there are several irregularities in real distribution systems which cannot be handled by one recloser alone. The power density distribution impacts the influence of feeder automation on the total outage cost-reduction of distribution systems. The cost-reduction capability of feeder automation is most effective in inhomogeneous distribution systems. In addition to the impact of feeder automation the generic distribution system also demonstrates the impact of different cabling techniques (UGC, COC) and distribution systems (1000 V, satellite) on the total outage cost-reduction capability.

Appendix 14 gives a summary on the basic features of the studied different feeders without feeder automation. When the feeders are compared to each other it should be remembered that they differ regarding feeder average power, total line length, line type, underground cabling level and fault frequency. The average fault frequency per unit line length of the homogenous overhead line feeder and the generic feeder is approximately the same as in the real F2 feeder while the environment conditions in the real feeder F2 are much more severe. Conclusions regarding the performance of the generic feeders should only be drawn by comparing the generic feeders to each other.

7.5 Relevance and practicality

The practical relevance of this work is that it produces a set of cost-effective Finnish rural/sub-urban area generic model feeders for practical implementation, testing and benchmarking purposes. By comparing feeders to each other both the additional cost and the reliability improvement of more weather-proof distribution systems are now known. Because each generic model feeder is examined with respect to a broad range of distribution automation schemes also the influence of feeder automation is known in advance. This also enables cost-efficient investments by comparing the economic benefits and pay-back times of different investment programs to improve the electricity distribution reliability. The distribution companies can now choose not only the most cost-effective automation schemes for Finnish MV distribution systems but also the most efficient reliability improving distribution systems by comparing the indices of the different generic model feeders. The results can be applied to typical Finnish MV distribution feeders by comparing main feeder data of the real feeders with those of the generic model feeders.

The practical functionality of the solutions of the developed model feeders and feeder automation schemes has been the development of a modelling and calculation system suitable for combined cost, cost-efficiency and reliability calculations. For homogenous feeders equations for calculation of the annual total outage cost and reliability indices have been developed. By modifying the Excel spread sheet models generated for the generic feeders they can be used for calculation of the annual total cost, the annual total outage cost and cost saving, the payback time, as well as the reliability indices of different investment scenarios of real feeders in different distribution companies.

The theoretical relevance of the research is that by implementing a general theory regarding the electricity distribution reliability and the cost of non-delivered energy and auto-reclosing it is possible to deliver a broad, simplified and easy to implement theory of these phenomena. This is demonstrated by implementing ten different feeder automation schemes on six designed cost-effective generic feeder models examining the interaction of these on each other and other investment strategies.

The theoretical contribution of the solution shows how the improvement of *T–SAIDI* using remote control is not enough to deliver enough reliable electricity distribution supply in the future digital environment. The introduction of the unit cost values of non-delivered energy and auto-reclosing delivers a suitable tool for benchmarking future investments. With this tool the whole spectrum of the quality of electricity distribution can be monitored.

The input data is the measured average data of real Finnish distribution systems and the unit cost values of the Finnish regulation system. The models can be modified by changing the input data. Thus, the models can also be used for evaluation of the reliability and cost-efficiency of medium-voltage distribution systems of other countries by changing the input data to data relevant to the country.

As a result of the adaptation of the second regulatory period of 2008–2011, the profit of the utilities that improve the reliability of their distribution systems is mostly allowed to increase. In Finland, the annual worth of the cost related to interruptions of the distribution companies in 2006 was about 120 M€ while the profit was about 300 M€. If the distribution companies can reduce the cost related to interruptions to 105 M€, then half of the difference between the original value and the reduced value of the cost related to interruptions (7.5 M€) can be used to increase the electricity distribution price (Kinnunen 2008: 8). This work has shown that that there is no single investment strategy that is optimal for all distribution systems. The work presents different investment strategy alternatives for different distribution systems.

8 CONCLUSIONS

8.1 General

The key methods for improving the Finnish rural and sub-urban area electricity distribution reliability can be divided into fault reducing and fault restricting methods. Fault reducing investment strategies have been studied by Tampere University of Technology (Marttila et al. 2009). In this study the main focus has been on fault restricting investment strategies such as the extended use of feeder automation and a wider utilisation of the specific features of different feeder types. As has been found the different investment strategies influence each other. In this work these interrelations have been studied with regard to the cost-efficiency of different investments such as new primary distribution substations, central earth-fault current compensation, new switching stations, different feeder types, feeder automation, cabling and backup connections (Figure 76).

Cost-effective optimizing of the benefits of electricity distribution reliability improvements is a very complex task because the alternatives for doing this mostly influence each other. The incremental benefit/cost analysis shows that when choosing the most cost-efficient reliability improving investment, a second investment in most cases proves not cost-efficient. Thus, it is of vital importance to choose an investment strategy which, except for being cost-effective, also improves the reliability and reduces the total outage cost as much as possible. If not, the small improvement of the reliability of the distribution system, although cost-effective, may prevent further reliability improving investments.

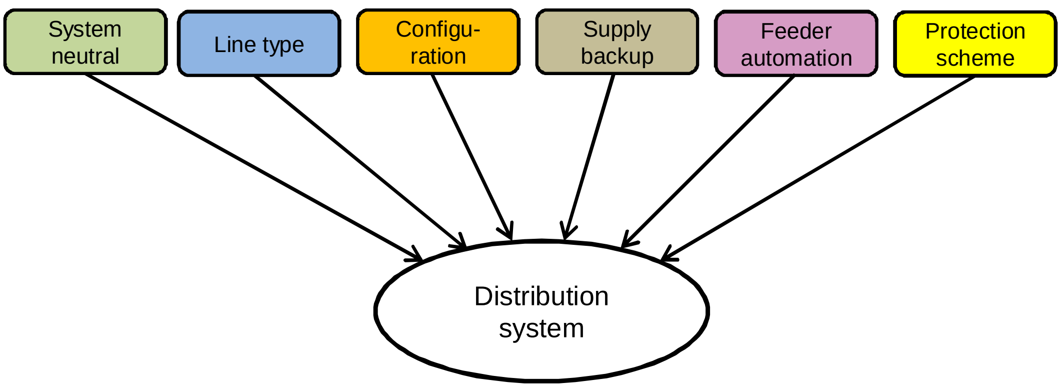


Figure 76. The areas for improving the reliability and availability of Finnish MV distribution systems.

8.2 Development of the economy and reliability of the electricity distribution on a national level

In Finland distribution automation is now being implemented in all the three sub-areas. Substation automation in the form of central earth-fault compensation is now used in the majority of the networks. Feeder automation is implemented by the use of remote controlled line switches/line switch groups. In 2009 a decree was released according to which 80 % of the Finnish households have to be provided with automatic meter reading by the end of 2013. Thus also customer automation is now widely being implemented.

The impact of different investment strategies depends on the operating environment, the existing distribution system and its qualities and properties. There are thus national, regional, distribution company and distribution system level differences. Next a summary of different effective investment strategies with regard to impact areas based on the study of a generic distribution system with input data typical for real distribution systems is given. The second Finnish regulatory period is the reference level of the economical indices. Both primary distribution substation and feeder level investments are considered.

8.2.1 Different reliability improving investment strategies

The number of primary distribution substations owned by the distribution companies in Finland was 786 in 2008 (FEI 2009). The number has increased equally as the total line length in Finland (Figure 77 a). New primary distribution substations are typically needed in existing or new industrial areas. A new primary distribution substation reduces the annual total outage cost on average by a half and improves the average reliability, feeder strength and fault management (Table 26). Even in pure overhead line networks with little or no feeder automation the payback time of a new primary distribution substation is relatively long. In mixed line networks a new primary distribution substation may be a solution to rearrange the overhead lines to one and the underground cable lines to another primary distribution substation.

Table 26. The impact of the investment strategy on the economic, reliability and environmental features of the Finnish distribution system. The grey area indicates impact area. Cost-effective implementation targets are given for each investment alternative. Investment specific results are also given where F refers to figure and T to table number. Implementation results for all investment alternatives are given in Figures 52, 53, 67 and 68.

Distribution system level	Investment option	Distribution system impact areas: Total economy	Total outage cost	Availability under fault conditions	Fault management	Feeder strength	Reliability	Weather proof
Primary distribution substation	Primary distribution sub-station type	New distribution systems						
	New primary distribution substation	Many, long, bad performing OHL feeders, little automation F47						
	Central earth-fault current compensation	Long OHL feeders		F50, F54, F55, F72, F73				
Feeder	Distribution substation and feeder type	New distribution systems F49, F66						
	Switching stations	Long OHL lateral lines F48						
	Backup connections	All distribution systems T10						
	Remote controlled line reclosers	OHL and mixed line feeders T2, T3, F24, F51						
	Remote controlled line switches	OHL and mixed line feeders T2, T3, F44						
	Fault indication	UGC networks						

Central earth-fault current compensation improves the economy and reliability of overhead line networks (Table 26). It reduces the number of auto-reclosings with approximately a half by reducing the steepness of the recovery voltage. It has been included in the investment program of many rural/sub-urban distribution companies in recent years and thus now about half of the total network length is earth-fault current compensated (Figure 77 b). In the digital society the reduction of transient faults is very important. The optimal neutral system of a distribution system depends on the environment and the feeder properties. Increased feeder average power, line length, earth-fault frequency and outage unit cost leads to better cost-efficiency of earth-fault current compensation. Increased underground cabling, however, reduces the cost-efficiency of earth-fault current compensation. Compensation may, however, be needed also in mixed line networks to reduce the capacitive current of the underground cables to a safe level with regard to the touch voltage. A question is if central earth-fault current compensation is efficient enough or if also local earth-fault current compensation is needed in selective underground cabling. In new overhead line and coated overhead conductor line networks central earth-fault current compensation together with remote controlled line reclosers is very cost-effective giving minimum annual total cost.

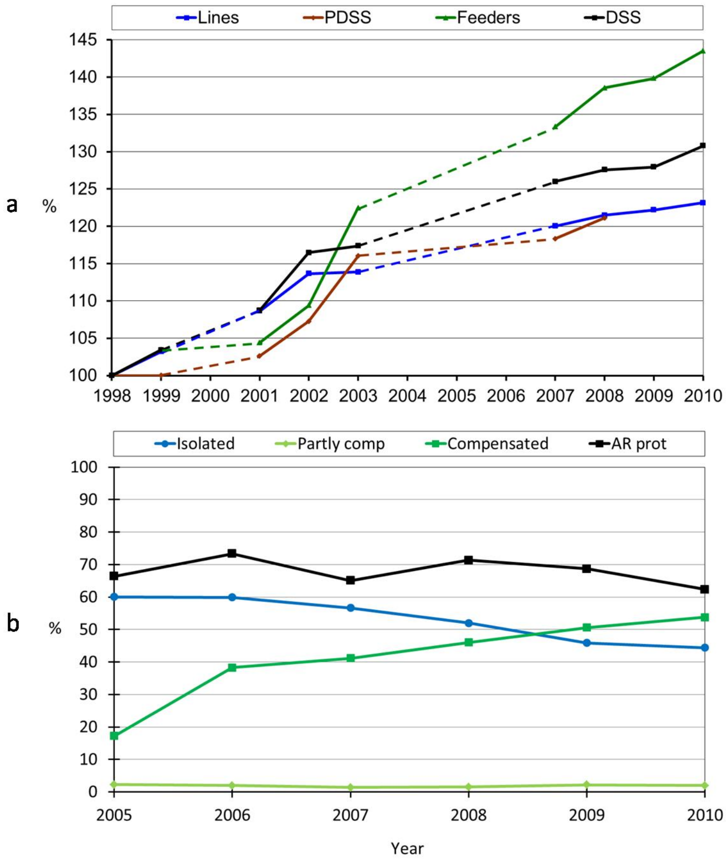


Figure 77. (a) The development of the total line length, number of primary distribution substations, number of feeders and distribution substations in the Finnish electricity distribution system 1998–2010. (b) The share of the length of MV neutral isolated, partially compensated and compensated distribution lines and the percentage of lines covered by the auto-reclosing function in the time period of year 2005–2010 in Finland. All networks (rural, urban and city) are included. (FEI 1999–2011)

8.2.2 Typical cost-effective locations

Normally even in rural feeders the first part of the outgoing feeders of the substation consists of underground cable. So far the reclosing function has been located in the substation. The role of the substation recloser earth-fault current protection function depends on the sensitivity of the earth-fault current protection function of the line reclosers compared to the sensitivity of the substation recloser. If the sensitivity is equal the substation recloser earth-fault current protection can be used as a back-up protection for the line reclosers. If the sensitivity of the line reclosers is lower than the sensitivity of the substation recloser the substation recloser earth-fault current protection relay detects the earth-faults that the line recloser protection relays cannot detect.

A summary of cost-effective implementation of line reclosing is presented in Figure 78. Feeder F1 demonstrates that remote controlled line reclosers are cost-effective in long overhead line feeders. The highest cost-effectiveness is found in feeders with no present feeder automation. With no existing remote controlled line switches the optimum location of the line recloser is halfway downstream of the feeder. As the number of reclosers increases the payback time becomes longer. On the other hand heterogeneity in the feeder may improve the cost-efficiency of an additional recloser. Feeder F2 demonstrates the use of line reclosing in mixed networks. The interface between an underground cable and an overhead line in a feeder may be a cost-effective location of a line recloser due to the large difference in the fault frequency of the two line types. The auto-reclosing function locates at the line recloser alone. It has also been found out that although the payback time of a recloser in a mixed feeder may be longer than in a corresponding overhead line feeder the total outage cost reduction capability may be higher in a mixed feeder (Figure 51, page 103). Feeder F3 demonstrates the effect of irregularities in the per-unit outage cost values and the average power. As the per-unit outage cost values differ up to 5.6–7.6 times dependent on the customer group it may be cost-effective to protect customers with high per-unit outage cost values from the effect of faults in other parts of the network. The average power of distributed generation is mostly representing a power concentration and thus it may be cost-effective to protect the generation from faults in other parts of the feeder. Distributed generation in a feeder may also blind the substation feeder protection when there is a fault in the feeder downstream of the generation because the generator feeds short-circuit current into the fault. Although the most cost-effective location of a line recloser in a feeder with a long branch is upstream of the branching point the beginning of a long branch may be a cost-effective location to protect the underground cable part of the feeder from a fault in the long overhead line branch (Feeder F4). The reclosing function is here locating only at the branch line recloser. Often the power density or/and customer per-unit cost value is higher in the first part of the feeder. This may make a line recloser cost-effective when protecting the first part of the feeder from the effect of faults in the rest of the feeder (F5 and F6).

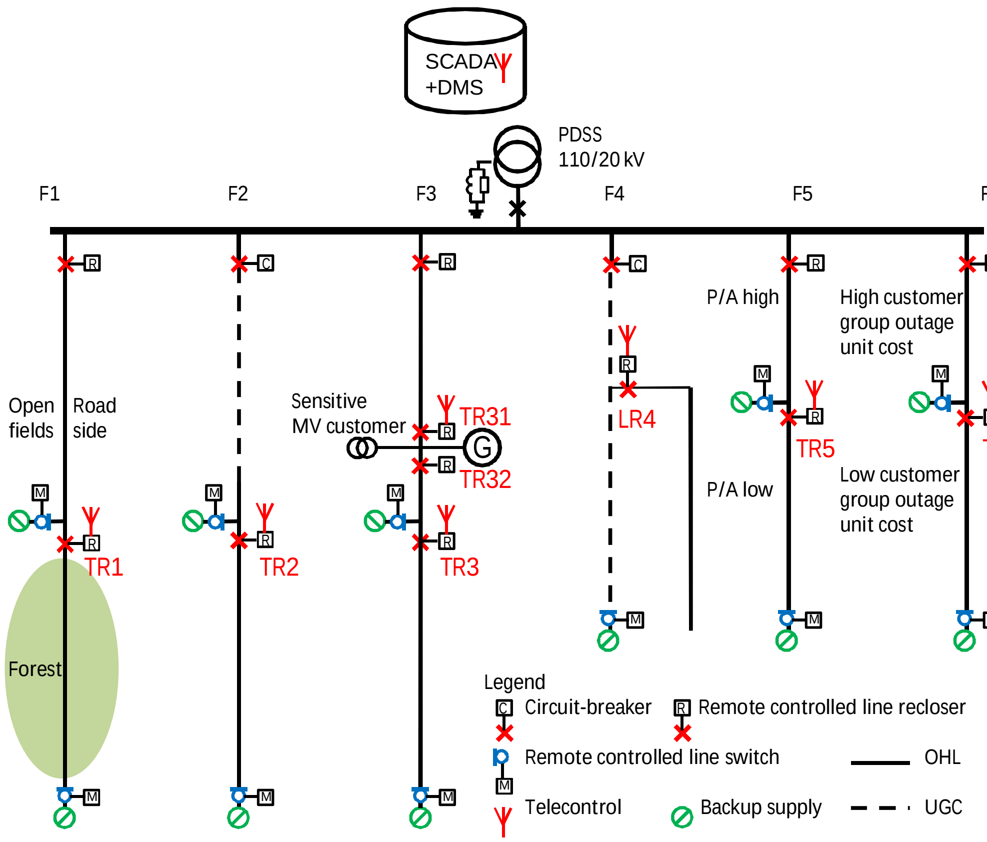


Figure 78. Typical applications of remote controlled line reclosers in inhomogeneous feeders.

Numerical protection relays can be set with a time discrimination of 100 ms enabling the use of several line reclosers in series while old protection relays may restrict the use of several line reclosers. The use of line reclosing will also increase the need for network investments, but the investments will be very cost-effective because they improve the availability of electricity supply by reducing the influence of interruptions. Earth-fault current compensation is cost-efficient in wide primary distribution substation areas with many overhead line feeders per substation while line reclosing is efficient in substation areas with a few feeders of which one or two have a lower reliability level than the other feeders. A very effective electricity distribution reliability improvement is achieved by using both central earth-fault current compensation and remote controlled line reclosers.

8.2.3 Zone handling

This study shows that cost-effective optimised reliability improving investment is achieved using remote controlled line reclosers in the feeder trunk (Figure 79). Optimal zone design uses remote controlled line reclosers and switches to divide the feeder into undependable contingency zones which can quickly restore supply whenever the fault is located anywhere outside the zone. It is also found that the optimal number of zones depends on the present degree of feeder automation, average load, line length, load type, underground cabling level and expected pay-back time of the investment. When considering the N–1 criterion in contingency planning, the loading level of the primary distribution transformer has also to be included when optimising the number of zones. The more primary distribution transformers that are connected to the feeder by backup connections the higher the loading level of the feeding primary distribution transformers can be (Table 10, page 70). The economic benefit of the higher loading level is however not included in this study.

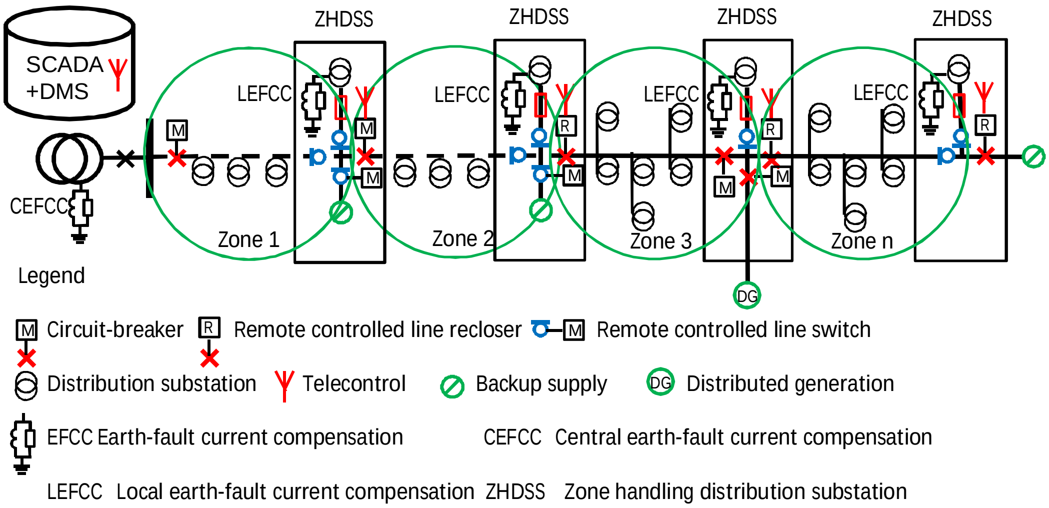


Figure 79. Optimal zone design utilises remote controlled line reclosers for limiting the effects of permanent faults and auto-reclosings and remote controlled switches for connection of supply backup in zone handling distribution substations.

The *zone handling distribution substation* (ZHDSS) contains one remote controlled line reclosers for protection, fault isolation and restoration, one remote controlled line switch for connection of backup supply and a fused switch-disconnector for the protection of the distribution transformer. It may also contain equipment for local earth-fault current compensation (LEFCC).

The cost-effectiveness of the solution is due to:

- Restricting of power interruptions to distribution substations downstream of the nearest remote controlled line recloser upstream of the fault location
- Restricting of the influence of interruptions to only the faulted zone by connecting backup supply with the remote controlled line switches
- A higher utilisation ratio of the primary distribution transformers due to linking of feeders between primary distribution transformers

8.2.4 Applicability of feeder automation

The remote control function has been available for some ten years in the primary distribution substations but has so far not been utilised in all the feeders. To optimise the total cost of electricity distribution the following step is to continue this utilisation of remote control by using remote controlled line reclosers. Further detailed study of practical applications will show to what extent this also includes replacing of existing remote controlled line switches. Let us estimate in how many feeders the remote controlled line recloser is a potential solution to improve electricity distribution reliability in Finland. Let the criteria of cost-efficiency be a payback time less than 1.2 years for the investment corresponding to line recloser R3 in the studied real feeder F1. From Figure 80 it can be interpreted that approximately 12 % of the Finnish medium voltage feeders have higher annual total outage cost than feeder F1. With a payback time of maximum 2.6 years it would be cost-effective to install remote controlled line reclosers in approximately 40 % of the Finnish rural network feeders. The corresponding number of feeders is about 415 for 12 % and 1390 for 40 % (FEI 2004:3). Another way to estimate the number of feeders where the application of remote-controlled line reclosers would be cost-effective is to calculate the number in one distribution company and multiply the number with the total number of distribution companies in Finland. (Lågland et al 2008). This method gives a minimum number of 700 and a maximum number of 1350 feeders suitable for installation of remote controlled line reclosers in Finland. The number of reclosers per feeder is 1–3.

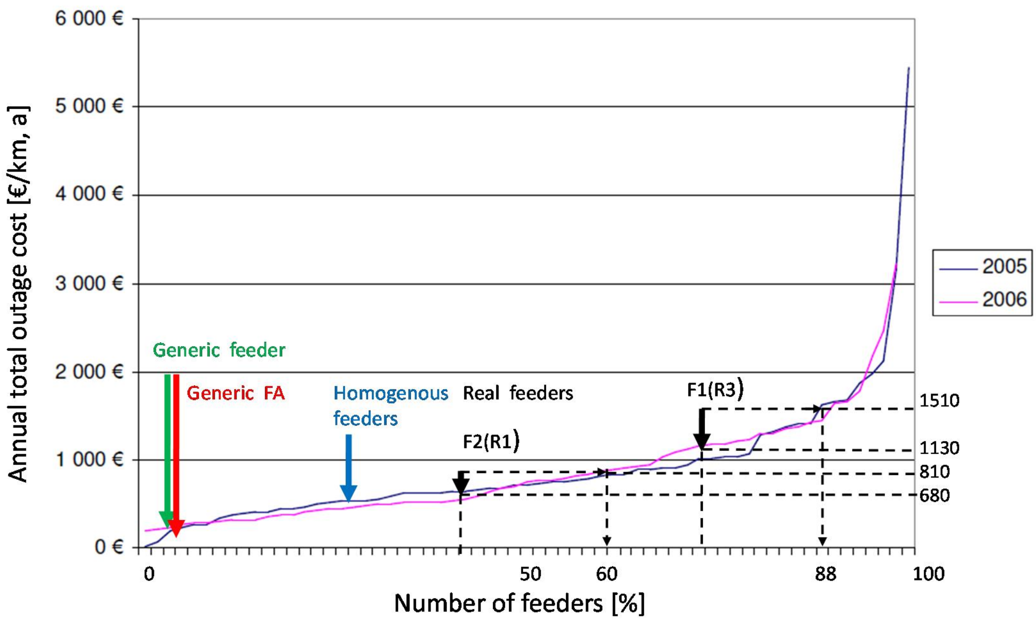


Figure 80. The annual total outage cost of 1 km feeder line in Finnish rural distribution companies in 2005 and 2006 (Adapted from EMA 2007 b: 31). The range of the homogenous and generic feeders without and with FA as well as the two real feeders have been added to the figure. For the two studied real feeders the starting points of the arrows show the initial value and the end point of the arrows the value of the annual total outage cost per km feeder with the first most cost-effective line recloser.

8.3 Applicability of the results and the generic model feeders

The results obtained can be utilized for:

- Forming an investment strategy for the long-term development of electricity distribution of the distribution companies with respect to cost-effectiveness and reliability
- Optimizing the utility incomes regarding the incentives included in the Finnish regulation of distribution companies
- Evaluation of the economical and electricity distribution reliability impacts of the second regulatory period when preparing for the third regulatory period
- Standardisation of the feeder types and feeder automation schemes of the distribution companies

- Benchmarking of different feeder types and feeder automation schemes with regard to different input data
- The developed equations for the reliability and economical indices of homogenous distribution systems can be used as a first estimation of the benefits of implementing feeder automation in real network feeders

The generic model feeders including feeder automation schemes developed can be used for:

- Research for making further conclusions regarding the cost-efficiency of electricity distribution reliability improvement methods
- Illustration of the influence of different input parameters on the reliability and economical indices
- For studying the distribution reliability of future distribution system concepts

The results of the economy and reliability of the generic feeders can be applied not only to making cost-effective automation investments in the existing medium voltage distribution systems, but also to come up with a strategy of how the qualities of the different distribution systems and automation schemes can be utilized in new distribution system investments. Knowing the impact of different automation schemes on the annual total outage cost of the different feeder types enables also the optimization of fault management with regard to the economy and reliability.

The following methods for improving electricity distribution reliability and economy on a system level have been studied: distribution system type, new primary distribution substation, central earth-fault current compensation, feeder switching station, feeder automation, under-ground and overhead cabling. Regarding economy and reliability the different methods are mostly influencing each other. When implementing several methods at the same time the benefits of the different methods may vary. The method which is most cost-effective for each case has to be known. The best solution is to create a strategy based on the general information available. This work gives general information on the interaction of different reliability improving methods and the cost-efficiency of different reliability improving strategies.

The electricity distribution sector in Finland is highly regulated and the return on investments in distribution networks is low. Low profits do not make the electricity distribution sector attractive to outside investors. During the second regulatory period of 2008–2011, incentives have been included into the Finnish regulation model which allows higher profits to the network owners for properly allocated network investments leading to lower operation and total outage cost. The regulation model also includes a shredder which lowers the permitted profit if the electricity distribution reliability has not developed according to the model. From a distribution company's of view, if a shredder is applied, there is most likely room for cost-effective distribution reliability improvements. Thus the introduction of the new regulatory period also offers several possibilities for cost-effective distribution reliability improvements to optimise the incomes of the distribution company, which also is an aim of the new regulation model.

8.4 Contribution to the research

In this doctoral thesis the sectionalisation concept has been further developed. The theoretical contribution has been the development of expressions for reliability and economical indices of homogenous distribution systems. For the calculation of the indices of inhomogeneous distribution systems the distribution system is divided into homogenous sections. The practical contribution is the launching of the zone handling distribution substation where the protection, fault management and earth-fault current compensation functions for the zone in question are located.

The main contribution of this doctoral thesis is the presentation of a comprehensive analysis to reveal the impact of distribution automation and distribution system on the performance of electricity distribution reliability and influenced costs and the effect on the efficiency/cost-efficiency of different alternative reliability improving investment strategies.

To be put into practice an investment has to be more cost-effective than other investment alternatives. The cost-efficiency of single investments varies depending on the used input data which also varies from time to time. A reliable investment decision is achieved by comparing different investment alternatives and choosing the ones with the best cost-effectiveness. In this study the cost-effectiveness of different investments has been compared with regard to system neutral, feeder type, feeder automation scheme, cabling level and feeder average power.

When maintaining or improving electricity distribution reliability the main focus is naturally put on fault preventing investments. This study has shown that with a relatively well performing distribution system different fault management strategies are cost-effective in that they allow continuing supply to the healthy distribution system thus improving the average availability of the electricity supply.

In his thesis Honkapuro stated that an evaluation of the regulatory effects on the long-term planning of distribution systems would be an interesting research topic in the future. This thesis gives information as to how different investment strategies can be utilised in cost-effective improvements of the electricity distribution supply reliability and availability in order to gain from the incentives of the second regulatory period. It also shows what are the reliability, availability and economic effects of the incentives of the second regulatory period on available different investment strategies of the distribution companies.

The demands of the digital society have changed the planning process of electricity distribution from a contingency based to a reliability based planning where feeder strength is in the focus of the planning process. Today cost-effectiveness is the main driver of every distribution company. Thus in addition to contingency-based planning reliability-based planning is needed to obtain a cost-effectiveness value for each contingency to be able to create a prioritization list for the investment alternatives. This study has showed that the outage unit cost series created for the Finnish second regulatory period is suitable to evaluate the cost of contingencies in the reliability-based planning approach.

When creating test systems for performance studies regarding technology, economy, reliability and distributed generation, normally one feeder for urban areas and one feeder for rural areas are selected. Doing so, only the features of the existing most common feeders can be examined. To find the most economic and reliable electricity distribution infrastructures several test feeders have to be created with regard to load density, network type, system neutral, protection and feeder automation as well as cabling level. Here, a set of six different generic model feeders, which combine the features of distribution systems in a way that optimises the reliability and economy have been identified modelled and compared with respect to reliability and economy.

A broad range of automation schemes have been applied to the different generic model feeders and real feeders in order to evaluate the influence of different feeder automation schemes on the performance and economy of the different investment alternatives and feeder types. Automation schemes used are, fault indication, remote control of line switches and reclosers, automatic switching and central earth-fault current compensation.

The study shows how differently these schemes influence the reliability and economy of the different feeder types and how the investment methods are interrelated. This creates a basis for forming a distribution company strategy to optimize electricity distribution reliability and economy as well as the economy of the distribution company and the reliability of electricity distribution to the customers.

8.5 The need for further research

According to Heilmann et al. (Heilmann, Sagoo & Bjørnvinsson 2005) sectionalisation is a first step in integrating distributed generation into the distribution system. When the level of distributed generation increases further steps are needed. Making sure that supply reliability and voltage quality remain at their existing level is an important issue to be solved when small wind generators (1–3 MW) are to be connected to the medium-voltage distribution systems. The question is how wind generators can be utilised to continue electricity distribution supply under fault conditions?

With microgrids further sectionalisation on the low voltage side of the distribution system is achieved (Laaksonen 2011). Therefore there is a need for further research in the utilisation possibilities of microgrids not only on the low-voltage level but also on the medium-voltage level.

A short-circuit always causes a voltage dip upstream of the activated line recloser. To fully benefit from the use of line reclosing it would be necessary to maintain the nominal voltage during the activation of the protection relay of the line recloser e.g. by energy storage devices. What kind of energy storage devices could be used and how and where should they be connected?

The consequences of using underground cabling in Finnish distribution networks have to be further investigated so that the protection issues related to the high-capacitive current of underground cable network lines can be solved. A Swedish survey is available, but because the main medium-voltage distribution system voltage in Finland is twice that of the Swedish, the capacitive zero-sequence current of the network is higher and this is a challenge for the protection system (Elfving et al. 2006).

As has been found, the earth-fault current compensation together with line reclosing is the optimum solution for Finnish overhead line distribution systems. To compensate for the reactive earth-fault current of underground cable lines compensation is needed. Optimal compensation is thus a prerequisite for a wider implementation of underground cabling in mixed line networks.

The present implementation of automatic meter reading and integrated remote control and protection functions in line reclosers are the first steps in the Finnish smart grid project and they will be followed by further steps as the project proceeds.

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APPENDICES

Appendix 1. Calculation of the substation level reliability indices in a homogenous OHL feeder protected by a substation recloser and equipped with only manually operated line switches.

Appendix 1.1 Calculation of *T–SAIFI*. The number of the distribution substation areas that are influenced by outage *i* is mpk_i and the total number of the distribution substation areas in the distribution area is *mp*.

Section		mpk_i
Load	Fault	
z1T	z1Tl	$k_d \cdot L/2 \cdot f_l \cdot L/2$
	z1Td	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2$
	z1Ll	$k_d \cdot L/2 \cdot f_l \cdot L/2$
	z1Ld	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2$
z1L	z1Tl	$k_d \cdot L/2 \cdot f_l \cdot L/2$
	z1Td	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2$
	z1Ll	$k_d \cdot L/2 \cdot f_l \cdot L/2$
	z1Ld	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2$
Σmpk_i		$4k_d \cdot L/2 \cdot f_l \cdot L/2 + 4k_d \cdot L/2 \cdot k_d f_d \cdot L/2\,)$
$T - SAIFI = \Sigma mpk_i \,/\, mp$		$f_l \cdot L + k_d f_d \cdot L$

Appendix 1.2 Calculation of *T–MAIFI* when the feeder auto-reclosing frequency is f_{AR} and *frAR is the* fraction of successful auto-reclosings. The number of the distribution substation areas that are influenced by the momentary outage *i* is mpk_i and the total number of distribution substation areas in the distribution area is *mp*.

Section		mpk_i
Load	Fault	
z1T	z1Tl	$k_d \cdot L/2 \cdot f_{AR} \cdot frAR \cdot L/2$
	z1Ll	$k_d \cdot L/2 \cdot f_{AR} \cdot frAR \cdot L/2$
z1L	z1Tl	$k_d \cdot L/2 \cdot f_{AR} \cdot frAR \cdot L/2$
	z1Ll	$k_d \cdot L/2 \cdot f_{AR} \cdot frAR \cdot L/2$
Σmpk_i		$4k_d \cdot L/2 \cdot f_{AR} \cdot frAR \cdot L/2$
$T-MAIFI = \Sigma mpk_i / mp$		$f_{AR} \cdot frAR \cdot L$

Appendix 1.3 Calculation of *T–SAIDI* when $m = k_d L/2n$. The number of outages is *z*. The number of different outage durations related to a certain outage is *x*. The number of distribution substation areas in the areas where the outage duration was t_{ij} is mpk_{ij}.

Section		$\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$
Load	Fault	
z1T	z1Tl	$k_d \cdot L/2 \cdot f_l \cdot L/2 \cdot t_s$
	z1Td	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_s + k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_r / m$
	z1Ll	$k_d \cdot L/2 \cdot f_l \cdot L/2 \cdot t_s$
	z1Ld	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_s$
z1L	z1Tl	$k_d \cdot L/2 \cdot f_l \cdot L/2 \cdot t_s$
	z1Td	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_s + k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_r / m$
	z1Ll	$k_d \cdot L/2 \cdot f_l \cdot L/2 \cdot t_s + k_d \cdot L/2 \cdot f_l \cdot L/2 \cdot t_r / m$
	z1Ld	$k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_s + k_d \cdot L/2 \cdot k_d f_d L/2 \cdot t_r / m$
$\sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$		$4k_d \cdot L/2 \cdot f_l \cdot L/2 \cdot t_s + 4k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_s +$
		$3k_d \cdot L/2 \cdot k_d f_d \cdot L/2 \cdot t_r / m + k_d \cdot L/2 \cdot f_l \cdot L/2 \cdot t_r / m$
T–SAIDI = $\sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij} \times t_{ij} / mp$		$f_l \cdot L \cdot t_s + k_d f_d \cdot L \cdot t_s + 3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r$

Appendix 2. Calculation of substation level reliability indices in a homogenous OHL feeder protected by a substation recloser and equipped with two remote controlled line reclosers and sectionalisation zones.

Appendix 2.1 Calculation of *T–SAIFI*. The number of the distribution substation areas that are influenced by outage *i* is mpk_i and the total number of the distribution substation areas in the distribution area is *mp*.

Section		mpk_i
Load	Fault	
z1T	z1Tl	$k_d L/4 \cdot f_l L/4$
	z1Td	$k_d L/4 \cdot k_d f_d L/4$
	z1Ll	$k_d L/4 \cdot f_l L/4$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4$
	z2Tl	0
	z2Td	0
	z2Ll	0
	z2Ld	0
z1L	z1Tl	$k_d L/4 \cdot f_l L/4$
	z1Td	$k_d L/4 \cdot k_d f_d L/4$
	z1Ll	$k_d L/4 \cdot f_l L/4$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4$
	z2Tl	0
	z2Td	0
	z2Ll	0
	z2Ld	0
z2T	z1Tl	$k_d L/4 \cdot f_l L/4$
	z1Td	$k_d L/4 \cdot k_d f_d L/4$
	z1Ll	$k_d L/4 \cdot f_l L/4$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4$
	z2Tl	$k_d L/4 \cdot f_l L/4$
	z2Td	$k_d L/4 \cdot k_d f_d L/4$

(continues)

Appendix 2.1 (continues)

	z2Ll	$k_d L/4 \cdot f_l L/4$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4$
z2L	z1Tl	$k_d L/4 \cdot f_l L/4$
	z1Td	$k_d L/4 \cdot k_d f_d L/4$
	z1Ll	$k_d L/4 \cdot f_l L/4$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4$
	z2Tl	$k_d L/4 \cdot f_l L/4$
	z2Td	$k_d L/4 \cdot k_d f_d L/4$
	z2Ll	$k_d L/4 \cdot f_l L/4$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4$
Σmpk_i		$3/4 \cdot k_d L \cdot f_l L + 3/4 \cdot k_d L \cdot k_d f_d L$
$T-SAIFI = \Sigma mpk_i / mp$		$3/4 \cdot f_l L + 3/4 \cdot k_d f_d L$

Appendix 2.2 Calculation of *T–MAIFI* when the feeder auto-reclosing frequency is f_{AR} and *frAR* is the fraction of successful auto-reclosings. The number of the distribution substation areas that are influenced by the momentary outage *i* is mpk_i and the total number of distribution substation areas in the distribution area is *mp*.

Section		mpk_i
z1T	z1Tl	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z1Ll	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z2Tl	0
	z2Ll	0
z1L	z1Tl	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z1Ll	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z2Tl	0
	z2Ll	0
z2T	z1Tl	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z1Ll	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z2Tl	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z2Ll	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$

(continues)

Appedix 2.2 (continues)

z2L	z1Tl	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z1Ll	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z2Tl	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
	z2Ll	$k_d L/4 \cdot f_{AR} L/4 \cdot frAR$
Σmpk_i		$3/4 \cdot k_d L \cdot f_{AR} L \cdot frAR$
$T-MAIFI = \Sigma mpk_i / mp$		$3/4 \cdot f_{AR} L \cdot frAR$

Appendix 2.3 Calculation of *T–SAIDI* when $m = k_d L/2n$. The number of outages is *z*. The number of different outage durations related to a certain out-age is *x*. The number of distribution substation areas in the areas where the outage duration was t_{ij} is mpk_{ij}.

Section		$\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$
Load	Fault	
z1T	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s$
	z2Tl	0
	z2Td	0
	z2Ll	0
	z2Ld	0
z1L	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s + k_d L/4 \cdot f_l L/4 \cdot t_r / m$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Tl	0
	z2Td	0
	z2Ll	0
	z2Ld	0

(continues)

Appendix 2.3 (continues)

z2T	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z2Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s$
z2L	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z2Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s + k_d L/4 \cdot f_l L/4 \cdot t_r / m$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
$\sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$		$8k_d L/4 \cdot f_l L/4 \cdot t_s + 8k_d L/4 \cdot k_d f_d L/4 \cdot t_s +$ $4k_d L/4 \cdot f_l L/4 \cdot t_c + 4k_d L/4 \cdot f_l L/4 \cdot t_c +$ $3/2 \cdot k_d f_d L \cdot t_r + 1/2 \cdot f_l L \cdot t_r$
$T - SAIDI = \sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij} \times t_{ij} / mp$		$1/2 \cdot f_l L \cdot t_s + 1/2 \cdot k_d f_d L \cdot t_s +$ $1/4 \cdot f_l L \cdot t_c + 1/4 \cdot f_l L \cdot t_c +$ $3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r$

Appendix 3. Calculation of *T–SAIDI* in a homogenous OHL feeder protected by a substation recloser and equipped with two remote controlled line switches when $m = k_d L/2n$. The number of outages is *z*. The number of different outage durations related to a certain out-age is *x*. The number of distribution substation areas in the areas where the outage duration was t_{ij} is mpk_{ij}.

Section		$\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$
Load	Fault	
z1T	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s$
	z2Tl	0
	z2Td	0
	z2Ll	0
	z2Ld	0
z1L	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s + k_d L/4 \cdot f_l L/4 \cdot t_r / m$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Tl	0
	z2Td	0
	z2Ll	0
	z2Ld	0
z2T	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z2Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s$

(continues)

Appendix 3 (continues)

z2L	z1Tl	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z1Ll	$k_d L/4 \cdot f_l L/4 \cdot t_c$
	z1Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_c$
	z2Tl	$k_d L/4 \cdot f_l L/4 \cdot t_s$
	z2Td	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
	z2Ll	$k_d L/4 \cdot f_l L/4 \cdot t_s + k_d L/4 \cdot f_l L/4 \cdot t_r / m$
	z2Ld	$k_d L/4 \cdot k_d f_d L/4 \cdot t_s + k_d L/4 \cdot k_d f_d L/4 \cdot t_r / m$
$\sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$		$8k_d L/4 \cdot f_l L/4 \cdot t_s + 8k_d L/4 \cdot k_d f_d L/4 \cdot t_s +$ $4k_d L/4 \cdot f_l L/4 \cdot t_c + 4k_d L/4 \cdot f_l L/4 \cdot t_c +$ $3/2 \cdot k_d f_d L \cdot t_r + 1/2 \cdot f_l L \cdot t_r$
$T - SAIDI = \sum_{i=1}^{z}\sum_{j=1}^{x} mpk_{ij} \times t_{ij} / mp$		$1/2 \cdot f_l L \cdot t_s + 1/2 \cdot k_d f_d L \cdot t_s +$ $1/2 \cdot f_l L \cdot t_c + 1/2 \cdot f_l L \cdot t_c +$ $3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r$

Appendix 4. Calculation of substation level reliability indices in a homogenous OHL feeder protected by a substation recloser and equipped with three remote controlled line reclosers and sectionalisation zones.

Appendix 4.1 Calculation of *T–SAIFI* and *T–SAIDI* when $m = k_d L/2n$. The number of the distribution substation areas that are influenced by outage i is mpk_i and the total number of the distribution substation areas in the distribution area is mp. The number of outages is z. The number of different outage durations related to a certain out-age is x. The number of distribution substation areas in the areas where the outage duration was t_{ij} is mpk_{ij}.

Section		Reliability indices	
Load	Fault	mpk_i	$\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$
z1T	z1Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z1Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_s$
	z1Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot (t_s + t_r/m)$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_s$
	z2Tl	0	0
	z2Td	0	0
	z2Ll	0	0
	z2Ld	0	0
	z3Tl	0	0
	z3Td	0	0
	z3Ll	0	0
	z3Ld	0	0
z1L	z1Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z1Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r/m)$
	z1Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot (t_s + t_r/m)$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r/m)$
	z2Tl	0	0
	z2Td	0	0
	z2Ll	0	0

(continues)

Appendix 4.1 (continues)

	z2Ld	0	0
	z3Tl	0	0
	z3Td	0	0
	z3Ll	0	0
	z3Ld	0	0
z2T	z1Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_c + t_r / m)$
	z1Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z2Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z2Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_s$
	z3Tl	0	0
	z3Td	0	0
	z3Ll	0	0
	z3Ld	0	0
z2L	z1Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z1Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z2Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z2Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot (t_s + t_r / m)$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z3Tl	0	0
	z3Td	0	0
	z3Ll	0	0
	z3Ld	0	0
z3T	z1Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$

(continues)

Appendix 4.1 (continues)

	z1Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z3Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z3Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_s$
z3L	z1Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z1Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Tl	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z3Td	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z3Ll	$k_d L/6 \cdot f_l L/6$	$k_d L/6 \cdot f_l L/6 \cdot (t_s + t_r / m)$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6$	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
T–SAIFI = $\Sigma mpk_i / mp$		$2/3 \cdot f_l L + 2/3 \cdot k_d f_d L$	
$T - SAIDI = \sum_{i=1}^{z} \sum_{j=1}^{x} mpk_{ij} \times t_{ij} / mp$			$1/3 \cdot f_l L \cdot t_s + 1/3 \cdot k_d f_d L \cdot t_s +$ $1/3 \cdot f_l L \cdot t_c + 1/3 \cdot k_d f_d L \cdot t_c +$ $3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r$

Appendix 4.2 Calculation of *T–MAIFI*. Feeder auto-reclosing frequency is f_{AR} and *frAR* is the fraction of successful auto-reclosings. The number of the distribution substation areas that are influenced by the momentary outage *i* is mpk_i and the total number of distribution substation areas in the distribution area is *mp*.

Section		mpk_i
Load	Fault	
z1T	z1Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z1Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Tl	0
	z2Ll	0
	z3Tl	0
	z3Ll	0
z1L	z1Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z1Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Tl	0
	z2Ll	0
	z3Tl	0
	z3Ll	0
z2T	z1Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z1Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z3Tl	0
	z3Ll	0
z2L	z1Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z1Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z3Tl	0
	z3Ll	0

(continues)

Appendix 4.2 (continues)

z3T	z1Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z1Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z3Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z3Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
z3L	z1Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z1Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z2Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z3Tl	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
	z3Ll	$k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
Σmpk_i		$24k_d L/6 \cdot f_{AR} L/6 \cdot frAR$
$T-MAIFI=\Sigma mpk_i / mp$		$2/3 \cdot f_{AR} L \cdot frAR$

Appendix 5. Calculation of *T–SAIDI* of a substation recloser protected homogenous OHL feeder with three zones divided by three remote controlled line switches, one halfway downstream the feeder trunk line and the other at the feeder end, when $m = kdL/2n$. The number of outages is z. The number of different outage durations related to a certain outage is x. The number of distribution substation areas in the areas where the outage duration was t_{ij} is mpk_{ij}.

Section		Reliability indices
Load	Fault	$\sum_{j=1}^{x} mpk_{ij} \times t_{ij}$
z1T	z1Tl	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z1Td	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z1Ll	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_s$
	z2Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
z1L	z1Tl	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z1Td	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z1Ll	$k_d L/6 \cdot f_l L/6 \cdot (t_s + t_r / m)$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z2Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$

(continues)

Appendix 5 (continues)

	z3Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
z2T	z1Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z1Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z2Td	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z2Ll	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_s$
	z3Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
z2L	z1Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z1Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z2Td	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z2Ll	$k_d L/6 \cdot f_l L/6 \cdot (t_s + t_r / m)$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z3Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
z3T	z1Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z1Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$

(continues)

Appendix 5 (continues)

	z2Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Tl	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z3Td	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z3Ll	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_s$
z3L	z1Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z1Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z1Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Tl	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Td	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z2Ll	$k_d L/6 \cdot f_l L/6 \cdot t_c$
	z2Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot t_c$
	z3Tl	$k_d L/6 \cdot f_l L/6 \cdot t_s$
	z3Td	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
	z3Ll	$k_d L/6 \cdot f_l L/6 \cdot (t_s + t_r / m)$
	z3Ld	$k_d L/6 \cdot k_d f_d L/6 \cdot (t_s + t_r / m)$
$T - SAIDI = \sum_{i=1}^{z} \sum_{j=1}^{x} mpk_{ij} \times t_{ij} / mp$		$1/3 \cdot f_l L \cdot t_s + 1/3 \cdot k_d f_d L \cdot t_s +$ $2/3 \cdot f_l L \cdot t_c + 2/3 \cdot k_d f_d L \cdot t_c +$ $3/2 \cdot f_d \cdot t_r + 1/2 \cdot f_l / k_d \cdot t_r$

Appendix 6. Calculation of the annual cost of AR when f_{HSAR} is the feeder HSAR frequency, f_{DAR} the feeder DAR frequency, c_{HSAR} the unit cost of HSAR and c_{DAR} the unit cost of DAR. The feeder is protected by a substation recloser and equipped with three remote controlled line reclosers and sectionalisation zones.

Sectionalisation zone	$f_{HSARi} \cdot c_{HSAR} \cdot P_i + f_{DARi} \cdot c_{DAR} \cdot P_i$
z1	$f_{HSAR} \cdot L/3 \cdot P \cdot c_{HSAR} + f_{DAR} \cdot L/3 \cdot P \cdot c_{DAR}$
z2	$f_{HSAR} \cdot L/3 \cdot 2/3 \cdot P \cdot c_{HSAR} + f_{DAR} \cdot L/3 \cdot 2/3 \cdot P \cdot c_{DAR}$
z3	$f_{HSAR} \cdot L/3 \cdot 1/3 \cdot P \cdot c_{HSAR} + f_{DAR} \cdot L/3 \cdot 1/3 \cdot P \cdot c_{DAR}$
$C_{AR} = \sum f_{HSARi} \cdot c_{HSAR} \cdot P_i + \sum f_{DARi} \cdot c_{DAR} \cdot P_i$	$2/3 \cdot \left(f_{HSAR} \cdot L \cdot P \cdot c_{HSAR} + f_{DAR} \cdot L \cdot P \cdot c_{DAR} \right)$

Appendix 7. Used fault frequencies, unit cost values, repair and switching times and AR frequencies.

Parameter	**Symbol**	**Unit**	**Distribution system**		
			Homogeneous	**Generic**	**Case study**
Fault frequencies					
– OHL, average	f_l	1/100 km, a	4.62	4.62	8.85, 5.72[1]
open field					4.85, 3.13[1]
forest					16.5, 10.7[1]
– UGC				1.64	2.90, 1.88[1]
– COC, 20 kV				1.11	3.30, 2.13[1]
– COC, 1 kV				1.68	
– Distribution substation	f_d	1/100 DSS, a	0.76	0.26–0.76	1.45, 0.94[1]
Feeder width	k_w	1	1.0	1.47, 0.85[2]	
Per-unit cost values					
– power not supplied	a	€/kW, a	1.42	1.42	1.42
– energy not supplied	b	€/kWh	14.2	14.2	14.2
Repair times	t_r	h			
– line, UGC				12	24
– line, OHL			2	2	3
– distribution substation			4	4	4
Switching time		h			
– manual switching	t_s		1	0.88–	1
– remote control	t_c		0.1	0.033	0.1
Per-unit cost values for the power not supplied		€/kW, a			
– HSAR	c_{HSAR}		0.71	0.71	0.71
– DAR	c_{DAR}		1.42	1.42	1.42
Average frequencies					
– AR	f_{AR}	1/100 km, a	62.9	62.9	62.9
– fraction of successful AR	$frAR$	%	90	90	90

[1] Fault frequencies used for internal allocation of faults in the case study (EMA 2004). To correspond to the measured real fault frequencies the fault frequencies used have been multiplied with a correction factor, which for feeder F1 was 1.648 and F2 1.066.

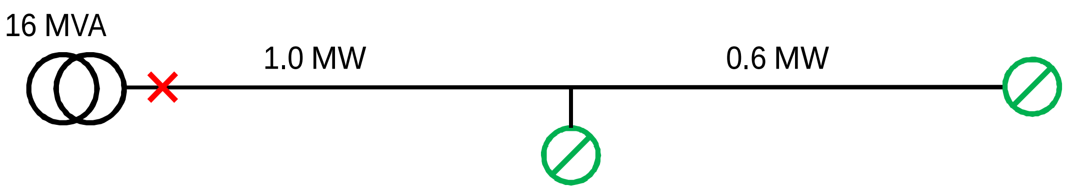
[2] ugc_ohl and ugcT_ohl

Appendix 8. Line dimensioning and tapering.

Appendix 8.1 Electrical properties and economical load capacities for some lines used in Finland (FEI 1994).

Line	**Electrical properties**				**Load capacity**	
	Nominal current A	Short-circuit strength kA	R_u[1] Ω/km	X_u Ω/km	Thermal MVA	Economical[2] MVA
OHL						
Fersemal	145	1.9	1.56	0.398	5.0	0–0.7
Raven	280	5.1	0.578	0.368	9.7	0.7–1.6
AL132	495	11.6	0.236	0.344	17.1	1.6–2.9
AL201	645	17.7	0.155	0.331	22.3	3–4
COC						
SAX-W 120	430	11.0	0.311	0.284	14.8	
SAX-W 70	310	6.4	0.533	0.302	10.7	
OHC, 1 kV						
AMKA 120			0.273	0.092		0.070–0.28
UGC						
70 mm² Al	205	5.7	0.571	0.132	7.1	0–2.8
185 mm² Al	345	15.0	0.215	0.114	11.9	4.2–6

[1] At +40 °C temperature
[2] 2 % load growth and 20 years lifetime

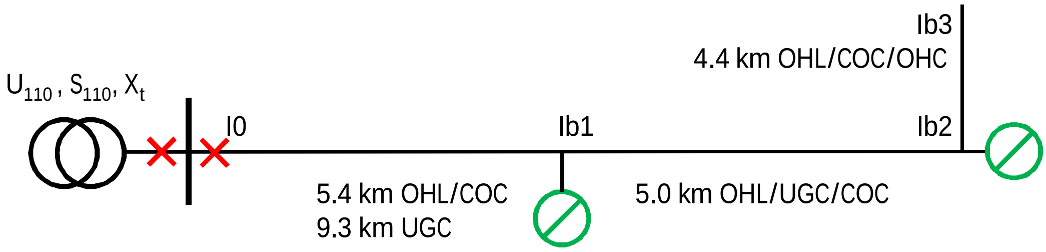


Appendix 8.2 Economic lines of the generic feeders (FEI 1985).

Generic feeders	ID	Dimension mm²	
		Feeder part	
		First	Second
The OHL feeder	ohl	AL132/Raven	
Mixed UGC/OHL feeder	ugc_ohl	Al185 mm²	AL132/Raven
Mixed UGC/OHL feeder	ugcT_ohl	Al185 mm²	Al185 mm²/Raven
The COC feeder	coc	SAX-W 120/SAX-W 70	
The satellite feeder	ugc_sat	Al185 mm²/ Al70 mm²	
The COC/1 kV feeder	coc_1kV	SAX-W 120/ 1–2xAMKA 120	

Appendix 9. Calculation of short-circuit strength and checking of protection constraints in different parts of the feeders.

Appendix 9.1 Calculation of the short-circuit strength in different parts of the generic feeders.



The short-circuit level of the primary side of the feeding network S_{110} is 5000 MVA (Lågland 2004: Appendix 16).

First half of the feeder (OHL):

$$X_{20} = U_{110}{}^2 / S_{110} \cdot U_{20}{}^2 / U_{110}{}^2$$

$$X_{20} = 110^2 / 5000 \cdot 20^2 / 110^2 \ \Omega = 0.08\ \Omega$$

$$X_t = z_k \cdot U_{2n}{}^2 / S_n$$

$$X_t = 0.10 \cdot 20^2 / 16 \ \Omega = 2.5\ \Omega$$

$$I_0 = \frac{20/\sqrt{3}}{0.08 + 2.5} \text{kA} = 4.5 \text{ kA}$$

Halfway downstream of the feeder:

$$\overline{Z} = \overline{Z}_{20} + \overline{Z}_t + \overline{Z}_l = R_l + j(X_{20} + X_t + X_l)$$

$$Z = \sqrt{1.28^2 + (0.08 + 2.5 + 1.86)^2}\ \Omega = 4.6\ \Omega$$

$$I_{b1} = 20/\left(\sqrt{3} \cdot 4.6\right) \text{ kA} = 2.5 \text{ kA}$$

End of the trunk line:

a) OHL

$$I_{b2} = 20 \Big/ \left(\sqrt{3} \cdot \sqrt{(1.28 + 1.04)^2 + (0.08 + 2.5 + 1.86 + 1.51)^2} \right) \text{kA} = 1.8 \text{ kA}$$

b) UGC

$$I_{b2} = 20 \Big/ \left(\sqrt{3} \cdot \sqrt{(0.99 + 2.74)^2 + (0.08 + 1.2 + 0.52 + 0.63)^2} \right) \text{kA} = 2.6 \text{ kA}$$

c) COC and 1000 V system

$$I_{b2} = 20 \Big/ \left(\sqrt{3} \cdot \sqrt{3.23^2 + (0.08 + 2.5 + 2.95)^2} \right) \text{kA} = 1.94 \text{ kA}$$

The end of the remote lateral:

a) OHL

$$I_{b3} = 20 \Big/ \left(\sqrt{3} \cdot \sqrt{(1.27 + 1.04 + 1.04)^2 + (0.08 + 2.5 + 1.86 + 1.51 + 1.51)^2} \right) \text{kA} =$$

1.4 kA

b) UGC

$$I_{b3} = 20 \Big/ \left(\sqrt{3} \cdot \sqrt{(0.99 + 2.74 + 1.26)^2 + (0.08 + 1.2 + 0.52 + 0.63 + 0.29)^2} \right) \text{ kA} =$$

1.8 kA

c) COC and 1000 V system

$$X_{t2} = 0.045 \cdot 1^2 / 315 = 0.14\ \Omega$$

$$I_{b3} = 1 \Big/ \left(\sqrt{3} \cdot \sqrt{(0.0081 + 0.03)^2 + (0.0002 + 0.0063 + 0.0074 + 0.14 + 0.001)^2} \right)$$

kA=

3.6 kA

Protection:

The protection constraint is:

$$I_{k2} = \sqrt{3} / 2 \cdot I_{k3} \geq 1.5 \cdot I_{lo},$$

where I_{k2} = two-phase fault current

I_{lo} = load current

Appendix 9.2 Checking of line short-circuit strength and protection constraints for the feeders at different locations.

Loca-tion	**Line type**	**Fault current** I_k **kA**	**Line area mm²**	**Feeder strength kA**	$\sqrt{3}/2 \cdot I_k$	$1.5 \cdot I_{lo}$
0	AL132 Al185 mm² SAX-W 120	4.5 4.5 4.5	132 185 120	11.6 15.0 11.0	3.9 3.9 3.9	0.070 0.070 0.070
1	AL132 Al185 mm² SAX-W 120	2.5	132 185 120	11.6 15.0 11.0	2.2	0.018 0.018 0.018
2	Raven Al70 mm² SAX-W 120	1.8 2.6 1.9		5.1 5.7 11.0	1.6 2.3 1.6	0.007 0.007 0.007
3	OHL UGC 1000 V	1.4 1.8 12.1	FS 70 OHC 120	1.9 5.7	1.2 1.6 3.6	0.003 0.003 0.003

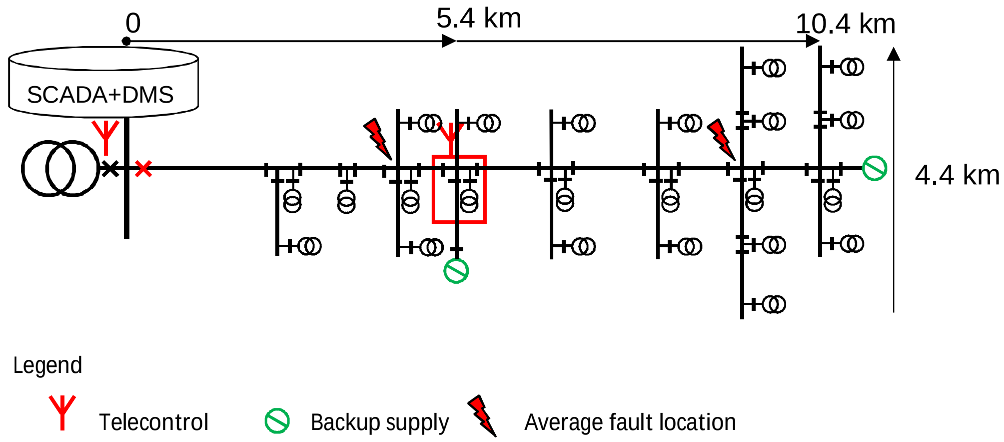
Appendix 10. The cost of network components and systems. Energy Market Authority 2010 unless otherwise expressed. The costs include installation.

Component/system	**Rating**	**Unit**	**Unit price** [k€]
Primary distribution substation			
Site	50x50	m^2	0.0028
Outdoor switchyard	Air-insul., 2-busbar	pcs	482
-additional cost/ cubicle	2	pcs	337
Substation building	1	pcs	241
Primary distribution transformers	16 MVA	pcs	358
	20 MVA	pcs	404
Indoor switchgear	20 kV, 1 busbar, air-insulated	pcs	22
-additional cost/ cubicle	13	pcs	14
Compensation system	2	pcs	126
Compensation coil	2	pcs	47
Management systems			
Distribution management system		pcs	322
-additional cost/ PDSS		pcs	11
-additional cost/ distribution subst.		pcs	2.4
-communication system		pcs	87
- communication system additional cost/ PDSS		pcs	5
Network information system		pcs	288
-additional cost/ customer		cust.	0.0045
Customer information system		pcs	288
-additional cost/ customer		cust.	0.0045
Lines			
OHL Al132		km	29
OHL Sparrow		km	18
OHC 1 kV AMKA 120		km	21
UGC 1 kV AL120		km	13.5
UGC Al 185		km	42
UGC Al 70		km	25
Digging, urban area		km	22
Digging, rural area		km	10
OHL terminal		pcs	2.65
UGC terminal		pcs	1.26
Distribution substations			
OHL 100 kVA, 20/0.4 kV		pcs	4.9
OHL 100 kVA, 20/0.4 kV, 4-p		pcs	7.2
OHL 315 kVA, 20/1 kV, 2-p		pcs	6.6
OHL 500 kVA, 20/1 kV, 2-p		pcs	6.6
OHL 100 kVA, 1/0.4 kV		pcs	4.0

Component/system	**Rating**	**Unit**	**Unit price** [k€]
UGC 500 kVA, 20/0.4 kV		pcs	28
UGC 100 kVA, 20/0.4 kV		pcs	28
UGC 315 kVA, 20/1 kV		pcs	28
UGC 500 kVA 20/1 kV		pcs	28
UGC 100 kVA, 20/1 kV		pcs	28
UGC 100 kVA, 1/0.4 kV		pcs	20
Coupling station			
UGC 20/0.4 kV, 1+2+4		pcs	40
UGC 20/0.4 kV, 1+2+2		pcs	30
Distribution transformers			
100 kVA, 20/0.4 kV		pcs	4.8
500 kVA, 20/0.4 kV		pcs	8.9
315 kVA, 20/1 kV		pcs	7.3
500 kVA, 20/1 kV		pcs	8.9
100 kVA, 1/0.4 kV		pcs	3.2
Automation equipment			
Manual fault indication		pcs	1.0
Remote fault indication		pcs	3.0
Remote control of line switch group (2 switches)		pcs	31.2
Remote operation function/distribution substation		pcs	3.2
Protection equipment			
Line recloser		pcs	22
1000 V protection		pcs	1.6

Appendix 11. Modelling of the supply restoration process and calculation of switching times of the different feeder automation schemes.

The restoration process is performed in two stages. At first trial switching is performed at the distribution substation between the first and second part of the feeder. In the second stage, the faulted equipment is located in the faulted feeder half and isolated by the crew and supply restored to the healthy sections of the feeder. *Switching time* is here defined as the time difference between fault initiation to the moment when the faulted section is isolated and supply restored to the healthy parts of the network.



$$t = a/v,$$

where t = driving time

a = distance

v = average driving speed

Calculated switching times when the average driving speed v = 30 km/h.

Automation scheme	Switching time			
	First part of the feeder		Second part of the feeder	
man	3 min+a/v+5 min+ 0.8/v+4·4 min	37 min	3 min+a/v+5 min+ 3.3/v+6·4.5 min	53 min
fi	3 min+a/v+3 min+ 0.8/v+3 min	20 min	3 min+a/v+3 min+ 3.3/v+3 min	25 min
rfi	3 min+a/v+3 min	15 min	3 min+a/v+3.3/v+ 3 min	22 min
rc	3 min+3 min+3 min	9 min	3 min+3 min+3 min	9 min
auto	Verification	2 min	Verification	2 min

Appendix 12. Finnish national MV network and fault statistics data 2003, 2007 and 2009 (EMA 2004, 2008 and 2010).

Indices	**2003**	**2007**	**2009**
Network statistics			
Reporting utilities	83	77	79
MV network length, km	124961	132225	134523
– OHL	113209	110838	110532
– UGC	11752	13113	14865
– Protected by AR	101410	87641	94138
Primary distribution substations	753	768	455
Feeders	5646	6146	6446
Distribution substations	119927	128743	130724
Distribution substations/ feeder	21.2	20.9	20.3
– Rural areas	28.7		
– Urban areas	9.4		
Distribution substations/ km	1.0		
– Rural areas	0.9		
– Urban areas	1.3		
Fault statistics			
Primary distribution substation, 1/a		0.29	0.29
OHL networks, 1/100 km, a	5.07	4.71	4.92
– Rural areas	5.37		
– Urban areas	2.94		
UGC networks, 1/100 km, a	1.86	0.70	0.76
– Rural areas	1.76		
– Urban areas	1.91		
Distribution substations 1/100, a	0.85	1.39	0.81
– Rural areas	0.88		
– Urban areas	0.62		
Protection			
– Successful HSAR, %	73	61	61
– Successful DAR, %	17	10	20
– Sustainable faults, %	10	30	19
Number of AR / 100 km, a			
HSAR		18.82	15.03
– Neutral isolated networks	51.0	21.90	
– Compensated networks	46.2	14.79	
DAR		6.55	4.87
– Neutral isolated networks		6.31	
– Compensated networks		5.37	

Appendix 13. Sensitivity study range.

Appendix 13.1 Studied variable data ranges.

Feeder property	**Minimum** (50 %)	**Base** (100 %)	**Maximum** (200 %)
Average power [MW]	0.8	1.6	3.2
Total line length [km]	12.9/13.2	25.7/26.4	51.4/52.8
Outage unit cost			
[€/kW, a]	0.71	1.42	2.84
[€/kWh]	7.1	14.2	28.4
Fault frequency			
OHL [1/100km, a]	2.3	4.6	9.2
UGC [1/100km, a]	0.75	1.5	3.0
COC [1/100km, a]	0.55	1.1	2.2
OHC [1/100km, a]	0.85	1.7	3.4
DSS [1/100, a]	0.1–0.4	0.2–0.8	0.4–1.6

Appendix 13.2 Variation range of the different variation ladders including the annual total cost of the generic ohl feeder forming the comparison level.

Variation ladder	**Variation ladder**							**C_{TOT} 100 %** [k€]
	range				**value definition**			
	k_P	k_L	k_{ouc}	k_{ff}	low short	medium	high long	
k_P	0.5–2.0 0.5–2.0 0.5–2.0	1 2 3	1 1 1	1 1 1	0.5–1.0	1.0–1.5	1.5–2.0	109 184 258
k_L	0.5 1.0 1.5	0.5–2.0 0.5–2.0 0.5–2.0	1 1 1	1 1 1	1	2	3	100 109 118
k_{ouc}	0.5 1.0 1.5	1 1 1	0.5–2.0 0.5–2.0 0.5–2.0	1 1 1	0.5–1.0	1.0–1.5	1.5–2.0	100 109 118
k_{ff}	0.5 1.0	1 1	1 1	0.5–2.0 0.5–2.0	0.5–1.0	1.0–1.5	1.5–2.0	100 109

Appendix 14. Comparison and summary of the features of the studied homogenous, real and generic feeders with nominal average power and without FA.

Variable	**Distribution system**								
		Real feeder		Generic					
	Homo-geneous	F1	F2	ohl	ugc_ohl	ugcT_ohl	coc	ugc_sat	coc_1kV
P [MW]	1.0	1.4	1.1	1.6	1.6	1.6	1.6	1.6	1.6
L [km]	30–100	54.5	68.5	25.7	26.4	26.4	25.7	25.7	25.7
UGC [%]	0.0	7.9	6.6	0.0	34.8	51.9	0.0	100.0	0.0
f [1/100 km, a]	5.3	7.9	5.4	5.3	4.1	3.5	1.8	2.1	2.7
T–SAIFI [1/a]	2.7	4.3	3.7	1.4	1.1	0.9	0.5	0.5	0.7
T–MAIFI [1/a]	25.0	28.0	25.6	16.2	10.8	7.6	8.1		
T–SAIDI [h/a]	2.1	4.5	3.9	1.2	1.0	0.8	0.4	0.3	0.3
f_{AR} [1/a]	31.5	27.4	25.5	16.2	10.8	7.6	8.1		3.3
C_{NDE} [k€/a]	37.4	100.6	65.9	27.8	20.1	17.6	9.7	7.5	6.9
C_{AR} [k€/a]	26.6	29.5	21.2	21.9	13.5	9.5	11.0		4.4
C_{INT} [k€/a]	64.0	130.0	87.2	49.8	33.5	27.2	20.7	7.5	11.4