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Monitoring of Electrical Distribution Network Operation

JAKO KILTER

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TALLINN UNIVERSITY OF TECHNOLOGY
Faculty of Power Engineering
Department of Electrical Power Engineering

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Supervisor: Professor Mati Meldorf, Department of Electrical Power Engineering, Tallinn University of Technology

Opponents: Professor Matti Lehtonen, Dr. Tech., Power Systems Laboratory, Helsinki University of Technology

Mart Landsberg, Ph.D, Head of Planning Division, OÜ Põhivõrk

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Declaration:
Hereby I declare that this doctoral thesis, my original investigation and achievement, submitted for the doctoral degree at Tallinn University of Technology has not been submitted for any academic degree.

Jako Kilter ……………….

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ABBREVIATIONS AND SYMBOLS

List of abbreviations

AC	Alternating Current
AM/FM	Automated Mapping and Facilities Management System
AMR/EMR	Automatic/Energy Meter Reading System
ARIMA	Autoregressive Integrated Moving Average Model
ARIMAX	Autoregressive Integrated Moving Average with Exogenous Variables Model
ARMA	Autoregressive Moving Average Model
ARMAX	Autoregressive Moving Average with Exogenous Variables Model
CIS	Customer Information System
DC	Direct Current
DIgSILENT	Power System Analysis Software
DEM	Distribution Energy Management System
DMS	Distribution Management System
DVR	Dynamic Voltage Restore
EHV	Extra High Voltage
ELMO	Electrical Load Monitoring
ElmoData	Load Data Management Software
ElmoDisco	Distribution Network Operation Monitoring Software
ElmoSet	Load Management Software
EMS	Energy Management System
EQL	Electricity Quality and Load System
FACTS	Flexible AC Transmission Systems
GIS	Geographical Information System
HV	High Voltage
LAN	Local Area Network
LV	Low Voltage
MV	Medium Voltage
PSS/E	Power System Simulator for Engineering
RTU	Remote Terminal Unit
SCADA	System Control and Data Acquisition
STATCOM	Static Synchronous Compensator
TCP/IP	Transmission Control Protocol / Internet Protocol
WAMS	Wide Area Monitoring System
WAN	Wide Area Network

List of symbols

$A(t)$	Trend
B	Susceptance
C	Capacitance

$E(t)$	Mathematical expectation
f	Frequency
G	Conductance
I	Current
$I_{t\%}$	Transformer no-load current as percentage from nominal current
k	Transformer ratio
P	Active power
R	Resistance
$R(t)$	Rate of temperature dependency
S	Apparent power
Q	Reactive power
Q_C	Compensating device reactive power
U	Voltage
$u_{k\%}$	Transformer short-circuit voltage
X	Reactance
Y	Admittance
Z	Impedance
$Z_{k\%}$	Transformer short-circuit reactance
ΔP	Active power loss in the line
ΔP_k	Transformer load losses
ΔP_t	Transformer no-load losses
ΔU	Voltage drop
ΔQ	Reactive power loss in the line
$\gamma(t)$	Temperature dependency of load
$\Theta(t)$	Stochastic component of load
$\zeta(t)$	Expected deviation of load
$\xi(t)$	Residual deviation of load
$\pi(t)$	Peak component of load

LIST OF ORIGINAL PAPERS

The present doctoral thesis is based partially on the following papers, which are referred to in the text by their Roman numerals I-VII:

[I] Meldorf, M., **Kilter, J.** Type models of Electrical Network Load. *Oil Shale*, 2009. Accepted for publication in *OilShale* Journal, vol. 26, No. 2.

[II] **Kilter, J.**, Meldorf, M. Monitoring of the Distribution Network Operation. In Proc. of *4th IASME/WSEAS Int. Conf. on Energy & Environment (EE´09)*. Cambridge, UK, February 24-26, 2009, pp. 263-268.

[III] **Kilter, J.**, Meldorf, M. Comprehensive Analysis of Electrical Distribution Network Operation – An Approach of Electrical Load Modelling. *WSEAS Transactions on Power Systems*. Issue 12, Volume 3, December 2008, pp. 725-734.

[IV] Meldorf, M., Täht, T., **Kilter, J.** Stochasticity of Electrical Network Load. *Oil Shale*, 2007, v.24 n.2S, 225-235 pp.

[V] Meldorf, M., Treufeldt, Ü., **Kilter, J.** Temperature Dependency of Electrical Network Load. *Oil Shale*, 2007, v.24 n.2S, 236-248 pp.

[VI] Meldorf, M., Treufeldt, Ü., **Kilter, J.** State Estimation Technique for Distribution Networks. *IEEE Conference Proceedings, PowerTech'05*. St. Petersburg. June 2005. Paper no. 374, 5 pp.

[VII] Meldorf, M., Treufeldt, Ü., **Kilter, J.** Estimation of Distribution Network State on the basis of a Mathematical Load Model. *Oil Shale*, 2005, Vol.22, No.2 Special, pp. 161 – 170.

The results of the above mentioned papers are comprehensively and profoundly enclosed into the following main text of this doctoral thesis.

Author's own contribution

The contribution by the author to the papers included in the thesis is as follows:

I Jako Kilter participated in writing the paper. He gathered and prepared the initial information for the analysis. He analysed and interpreted the results.

II Jako Kilter wrote the paper and is the corresponding author. He performed modelling and analysis of the study network and interpreted the results. He made the presentation of the paper at 4th *IASME/WSEAS International Conference on Energy & Environment* (EE´09), Cambridege, UK.

III Jako Kilter wrote the paper and is the corresponding author. He gathered and prepared the initial information for the analysis. He performed modelling and analysis of the study network and interpreted the results.

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VI Jako Kilter participated in writing the paper. He gathered and prepared the initial information. He interpreted and analysed the results. He made the presentation of the paper at *IEEE PowerTech* 2005 Conference, St. Petersburg.

VII Jako Kilter participated in writing the paper. He gathered and prepared the initial information for the analysis.

INTRODUCTION

Electrical power system consists of generators, transmission and distribution networks and consumers. The main purpose of the electrical network is to cover the load in all conditions, considering possible contingencies. This association forms a very complex system and understanding of its operation for system short-term and long-term planning and operational control, is essential.

Methods for the analysis of electrical networks have been studied even as long as is the existence of power systems. The main topics under observation have been the power flow problem and its solutions with different methods (Gauss-Seidel, Newton-Raphson, etc.), state estimation (topology analysis, bad data detection, state estimation, etc.), optimization of the system operation, load modelling (forecasting methods, dynamic methods, etc.), etc. Over many years, most of the attention has been paid to the development of the methods, related to transmission networks. This is understandable because the importance of transmission networks has always been understood and availability of initial information is extensive through different information systems (*SCADA*, *WAMS* etc.). However, attention should also be paid to the analysis and development of distribution networks and its problems because the importance and reliability requirements of power delivery to customers have increased noticeably. The actual security of supply and power quality from the customers' point of view is formed directly in distribution networks and also consideration of electricity market developments have caused the situation where larger understanding of distribution network operation is inevitable. In the last two decades, this situation has been noticed and a lot of attention has been given to the research and solving different problems, related especially to distribution networks and their operation.

The main question, when analysing the distribution network operation is where to get the initial information. Compared to the transmission networks, where data and information redundancy is noticeable, the situation in distribution networks is quite different. The operational information is predominantly available from larger substations when information, regarding the distribution substations and low-voltage networks is modest or sometimes not available at all. When considering the analysis of distribution networks, one must also consider the characteristics of the networks. Although a lot of methods have been developed for the transmission networks, it is not possible to employ them directly in the distribution network analysis. The problem is that, in general, the distribution networks are usually unbalanced three phase networks or even one phase networks, their configuration is radial or sometimes weakly meshed and the branches have usually high R/X ratios. For example, direct application of Newton-Raphson or other well-known methods for distribution networks power flow studies is complicated and in many cases leads to divergence and they are ineffective. Therefore, the main question in the development of appropriate methods for distribution network analysis is how to incorporate those characteristics in order to compose an efficient, reliable and robust algorithm and methodology.

Consequently, considering the above mentioned principles the development of adequate methods for distribution network analysis is understandable. This thesis proposes a comprehensive methodology to model and analyse the distribution network operation, based on the application of the mathematical model of load. Algorithms are proposed and tested in the real network and the results of the analysis have been presented.

The results of this thesis have been published in several journal papers (*Oil-shale*, *WSEAS Transactions on Power Systems*) and presented at several conferences (*IEEE PowerTech*, *WSEAS conference*, *Riga Technical University conferences*). All publications related to the topic of this doctoral thesis are presented in the *List of publications* at the end of this thesis.

OBJECTIVES AND CONTRIBUTIONS OF THE THESIS

The objective of this thesis is to elaborate theoretical approaches and develop methodology and practical solution for distribution network monitoring and analysis. The proposed methodology was applied to the Estonian distribution network to assess the network operation and study the properties and reliability of the measurement data, which in practice is used by network operators and engineers for network monitoring. The originality of the thesis is expressed by theoretical and practical results.

Theoretical originality can be found in the development of distribution network monitoring methodology, which includes distribution network representation, gathering of information, estimation of load model, network operation modelling and estimation, verification of results and models, and adequate decision making, considering the obtained results in different conditions. Completely new distribution network state estimation algorithm, based on the mathematical model of load is proposed. Theoretical discussion on considering the effect of temperature dependency and stochasticity of load to load modelling is presented and developments and improvements of the mathematical model of load are showed.

The practical originality includes comprehensive study for evaluating the reliability and authenticity of the distribution network *SCADA*-data, obtained from the actual network. It is showed that the proposed methodology is suitable for operation monitoring and for the estimation of network measurement data and operation. The results showed that it is possible to observe and analyse the distribution network data and operation efficiently. This methodology incorporates also the effect of load cases to the network operation.

The actuality of the thesis is based on the fact that the existing methods, used for load forecasting and distribution network operation analysis are based on forecasting models, which employ only the mathematics, based on time-series and not the real characteristics of load or are based on some other modest and unsophisticated methods. The presented methodology utilizes the mathematical model of load describing the nature of the load. Nowadays the investments required for distribution network enhancement are remarkable and therefore the decisive decisions made should be based on accurate forecasts and analysis. The proposed methodology offers a comprehensive possibility to model the network operation accurately. That enables the network operators to control and analyse the network operation more efficiently and in case of contingencies to restore the normal operation of the network more rapidly, guaranteeing the reliability and quality of power to consumers.

OUTLINE OF THE THESIS

This doctoral thesis is divided into six chapters. Chapters 1 to 3 give the background information, required to understand the characteristics of electrical networks and their operation. Chapters 4 to 6 discuss methods, proposed and used for monitoring of the distribution network operation.

Chapter 1 presents a literature review of various methods related to the topics of this doctoral thesis. Comprehensive overview of different methods and algorithms, proposed in the literature for electrical network load forecasting, for short-, medium- and long-term time periods, for distribution network power flow calculation and for distribution network state estimation, is presented.

Chapter 2 of the thesis gives profound understanding and background in the field of monitoring of the power system operation. The attention is paid to the transmission networks and their operation regularities. Discussion about different methods, used for power flow studies and state estimation, is presented.

Chapter 3 of the thesis describes the characteristics of distribution networks. Discussion about network control and monitoring (different communication systems etc.), possible network configurations, voltage regulation principles, measurement availability and placement, reactive power compensation principles, etc. is presented. Special attention is given to the modelling of distribution network operation. The basics of modelling the distribution network elements, e.g. lines, transformers, compensating devices, loads, etc. with methods employed to network steady-state calculations are given. Principles of optimal operation of distribution network are discussed.

Chapter 4 covers the principles of electrical network load and its characteristics and introduces the mathematical model of load. The mathematical model of load, described in this chapter, enables to develop new methodology for monitoring of the distribution network operation. Mathematical model of load describes the regular changes of load (daily, weekly and yearly periodicity and trend), stochasticity and dependency on temperature and state variables. Profound description of the influence of load cases and scenarios on network monitoring and analysis is given. The mathematical model of load describes the load, but it does not directly give the values that are required in practical applications (for example, load forecasts, etc.). The above mentioned practically required values, e.g. load characteristics, can be found, based on the mathematical model.

Chapter 5 includes the most important parts of this thesis. It describes the principles of proposed distribution network monitoring methodology and developed algorithm for distribution network state estimation. Results of the estimation of the distribution network load model are also presented. Proposed distribution network monitoring algorithm consists of network representation, gathering of information, estimation of the load model, and network operation modelling and estimation. The objective of the state estimation is to refine measuring data. It is especially important to clarify significant measuring errors or mistakes. Discussion of developed state estimation method, execution of state estimation, and editing of the load models, is presented.

Chapter 6 is dedicated to the implementation of the developed distribution network monitoring methodology. An application of load model in monitoring the distribution network operation is presented. An example network, which is a part of Estonian 35 kV distribution network, is used. In this chapter, the results of estimation of network load, calculation and estimation of the distribution network operation are presented. It is showed that it is necessary and possible to estimate the *SCADA*-data of operation.

In addition to the main part of this thesis, the introduction, conclusions and future work, references, list of publications, abstracts and curriculum vitae, are enclosed.

ACKNOWLEDGEMENTS

This doctoral thesis is a continuation of my research in the field of electrical network load that started over seven years ago under supervision of Professor Mati Meldorf. I would like to express my sincerest gratitude to him for his excellent guidance, continuous help both in technical and theory issues, intellectual and fruitful discussions, advice and constant encouragement during the whole period of this work. His enthusiasm to solve and study the load modelling issues and applications is remarkable and simply infectious.

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1 LITERATURE REVIEW

1.1 Forecasting of power system load

Load forecasting is an important and central process in the planning and operation of power systems. Accurate load forecasting enables to make important decisions considering purchasing and generating of electric power, network switchings, infrastructure developments, etc. Load forecasting is important to all participants in the electric energy chain e.g. producers, transmission and distribution system operators, market participants, etc.

Load forecasting can be divided into three categories: short-term forecasting which is usually from one hour to one week, medium-term forecasting which is usually from one week to a year, and long-term forecasting which is longer than a year [1]. Forecasting of load is usually performed by methods, which use statistical techniques or artificial intelligence algorithms such as regression, neural networks, fuzzy logic, and expert systems. Forecasts for different time periods are important for different purposes. For example, short-term load forecast can be used to estimate the load flows and to make decisions to prevent overloads. Load forecasts for months ahead can be used to assess the influence of maintenance and outages of different network elements to network operation. A long-term forecast is used as a base for investments to decide the necessity for new production units and transmission lines. Load forecasting is important for concluding contracts and evaluating of various sophisticated financial products on energy pricing offered by the market in shorter and in longer perspective.

For medium and long-term load forecasting the so-called end-use and econometric approach based methods or their combinations are broadly used. The end-use approach is based on directly estimating the consumers' energy consumption by considering the extensive information on end users, such as appliances, the customer characteristics, size of houses etc. The end-use models are based on the assumption that the electricity demand is derived from customers' demand for energy. However, this method is sensitive to the amount and quality of end-use data. The econometric models combine economic theory and statistical techniques. The approach estimates the relationships between energy consumption and factors influencing the consumption. The relationships are estimated by the least-squares method or time series methods. In [2] by Kandil, El-Debeiky and Hasanien a long-term load forecasting method based on expert systems is presented. The expert system is implemented to support the choice of the most suitable load forecasting model. Nagasaka and Al Mamun in [3] propose a long-term load forecasting method for radial networks. A combination of fuzzy logic with neural networks for long-term load forecasting is proposed by Padmakumari *et al.* in [4]. Medium and long-term load forecasting methods, based on neural networks, have been covered by Gavrilas, Ciutea and Tanasa in [5], and by Farahat in [6], respectively.

For short-term forecasting variety of methods, which include the so-called similar day approach, various regression models, time series, neural networks, statistical learning algorithms, fuzzy logic, and expert systems, have been developed.

A comprehensive literature survey and classification of load forecasting methods is given by Alfares and Nazeeruddin in [7].

Similar-day approach is based on searching historical data for days within one, two, three years with similar characteristics e.g. weather, weekday, date etc., to the forecast day. The load of a similar day is considered as a forecast, which can be a linear combination or regression procedure that can include several similar days.

Regression methods for electrical load forecasting are based on the assumption to model the relationship of load consumption and other factors, e.g. weather, day type etc. The model presented by Papalexopulos and Hesterberg in [8] produces an initial daily peak forecast and then uses the obtained forecast to produce initial hourly forecasts. In the next step, the maximum of the initial hourly forecast, the most recent initial peak forecast error, and exponentially smoothed errors as variables in a regression model are used to produce an adjusted peak forecast. Regression-based daily peak load forecasting method for a whole year including holidays is presented by Alfares and Nazeerudin in [9]. In the method different seasonal factors affect load differently in different seasons. For example, in a winter season, average wind chill factor is added as an explanatory variable in addition to explanatory variables used in the summer model. Different approaches of regression methods for load forecasting are presented in the literature [10], [11], [12], [13].

Time series methods are based on the fact that the data has an internal structure, including autocorrelation, trend, seasonal variation etc. Methods based on time series have been used for decades and the most frequently employed methods are *ARMA*, *ARIMA*, *ARMAX* and *ARIMAX*. Huang in [14] proposed an autoregressive model with an optimum threshold stratification algorithm, which determines the minimum number of parameters required to represent the random component, removing subjective judgement, and improving forecast accuracy. Huang and Shih in [15] proposed a method where the concept of cumulant and bispectrum are embedded into ARMA model in order to facilitate Gaussian and non-Gaussian process. Juberias *et al*. in [16] developed a real time load forecasting *ARIMA* model that includes the meteorological influence as an explanatory variable. Yang and Huang in [17] proposed a fuzzy autoregressive moving average method with exogenous input variables (*FARMAX*) for one day ahead hourly load forecasts. In the literature [18], [19], [20] other developments on time series methods for electrical load forecasting can be found.

The application of neural networks to load forecasting is one of the most widely researched electric load forecasting techniques since 1990's. The outputs of the artificial neural network are some linear or nonlinear mathematical functions of its inputs. In practice the network elements are arranged in a relatively small number of connected layers of elements between network inputs and outputs. When applying the neural network for electric load forecasting, one of the architectures (Hopfield, back propagation, Boltzmann machine), the number of connectivity layers and elements, use of bi-directional links, and the number format (binary or continuous) to be used by inputs, outputs and internally, must be selected. The most commonly used artificial neural network architecture for electric load forecasting is back propagation, which uses continuously valued functions and supervised learning. Comprehensive overview of neural networks methods for short-term load forecasting is presented by Hippert, Pedreira and Souza in [21]. In addition to direct application of neural networks, they have also been applied with other load forecasting methods. For example, neural networks based on fuzzy logic are discussed in [22], [23], [24]. Chow and Leung in [25] combined artificial neural network with stochastic time-series methods, in the form of non-linear autoregressive integrated model. Mori and Kosemura in [26] present an approach based on regression tree. Information on neural networks for electrical load forecasting has been extensively published in the literature [27]-[39].

Expert system is a program that, in addition to draw conclusions, has the ability to reason and explain, and have its knowledge base expanded as new information becomes available to it. The knowledge is presented as facts and IF-THEN rules, and consists of the set of relationships between the changes in the system load and changes in natural and forced condition factors that affect the use of electricity. The use of expert systems began in the 1960's. The method, where knowledge based system that considers the regularities of system load and weather parameters is proposed by Ho *et al.* in [40]. It is showed that the presented method has better performance compared to the Box-Jenkins method. A site independent technique for short-term load forecasting was developed by [41]. Brown *et al.* in [42] used a knowledge-based load-forecasting approach, where the existing system knowledge was combined to load growth patterns and horizon year data. Various combinations of expert systems to other electrical load forecasting methods, e.g. fuzzy logic, neural networks etc. have been published [43], [44], [45].

Load forecasting with fuzzy logic is based on the implementation of fuzzy sets theory. The approach is a generalization of the usual Boolean logic. Fuzzy logic enables to deduce outputs logically from fuzzy inputs. It is not needed to map inputs to outputs or there is no need for precise inputs. Mori *et al.* in [46] proposed a fuzzy approach for short-term load forecasting, where the tabu search with supervised learning to optimize the interference structure to minimize forecasts errors, is used. A combined approach of fuzzy logic, neural networks and expert systems with unsupervised learning to load forecasting is proposed by Srinivasan *et al.* in [47]. More applications of fuzzy logic for electrical network load forecasting are presented in literature [48], [49], [50].

When performing short-term forecast of load, several factors, for example, time factors (time of the year, day of the week etc.), weather data (temperature, humidity etc.), stochasticity, and information on possible load classes (residential, commercial, industrial), should be considered. During the medium and long-term forecasts also historical load and weather data, the number of customers in different categories, economic and demographical data, and their forecasts and other factors are considered.

Electrical network load dependency on temperature and on other weather factors has widely been covered in different papers. In [51] by Ružic, Vučković and Nikolić a regression-based adaptive weather sensitive short-term load forecasting approach has been presented. Proposed algorithm is robust and is not very sensitive to weather forecast accuracy considering only the data that has a great influence on consumption e.g. only minimal, maximal and average daily temperatures and average daily wind speed are used. Also, the extent and inertia of the temperature influence are considered. Weather impact on load diversity is covered in [52] by Ziser, Dong and Saha. To relate critical points in the load curve to weather factors, a multiple regression was applied. It is proposed that daily maximum temperatures are dominant weather factor, followed by humidity at times of maximum temperature, daily minimum temperature, wind speed and hours of sunshine. When considering the temperature, the effect of the previous day temperature is important. Owayedh, Al-Bassam and Khan in [53] indicate that temperature on the previous day is more important than the peak day temperature. That temperature physically represents the heat that is stored into buildings due to the previous day temperature.

The modelling of the stochasticity of the electrical network load is observed in many papers over the last two decades and different representations of the load distribution and correlation has been made. De Coutto Filho *et al*. in [54] present that most active and reactive daily peak load uncertainties in the system can be modelled by normal distributions. Herman and Kritzinger in [55] and Herman and Heunis in [56] propose that the best function to represent low-voltage network load is beta probability distribution function. Neimane in [57] uses three probability density functions, normal, log-normal and beta distribution, to model network load (load measured in 110 kV level) variations and concludes that all three distributions provide reasonably good representation of the load variations. However, if variations of modelled parameters are non-symmetrical, log-normal or beta distribution would give a better approximation.

1.2 Calculation of distribution network operation

Different methods have been developed to solve the electrical network load flow problems. The best known are the Newton-Raphson, Gauss-Seidel and fast decoupled load flow methods and their modifications [58], [59], [60], [61], [62]. However, these methods have been developed to solve the transmission network problems and therefore they are not directly applicable for distribution networks. The problem is that, in general, the distribution networks are usually unbalanced three phase networks, their configuration is radial or sometimes weakly meshed and the branches have usually high R/X ratios. It is stated that the direct application of the Newton-Raphson or other well-known methods to distribution networks power flow studies can be complicated and in many cases leads to divergence and also they are ineffective.

The above mentioned approaches to power flow studies may be named as deterministic methods. In addition, different approaches, based on probabilistic [63] and fuzzy sets methods [64], [65] to power flow studies, have been presented in literature.

The problems of distribution network load flow have been studied more intensively over last two decades. From the perspective of distribution network load flow analysis the developed methods could roughly be categorized as node based methods and branch based methods. The first category of methods uses node voltages or current injections as state variables. The most notable methods in this category are Newton-Raphson algorithm, fast decoupled algorithm, Z-bus Gauss method etc. The second category uses branch current or branch powers as state variables. The backward/forward sweep based methods and loop impedance methods can be categorized into this group.

Newton-Raphson method modifications for distribution network calculations have been developed and discussed by Chiang in [66]. Three decoupled distribution load flow algorithms have been presented and their convergence in different conditions is studied. Another Newton based fast decoupled power flow method is developed by Zimmermann and Chiang in [67]. The method is developed for unbalanced radial distribution systems and its behaviour, compared to other methods, was discussed. Lin and Teng in [68] present a current-injection based Newton-Raphson method in rectangular coordinates for distribution system load flow. The method employs sub-Jacobian G-matrix for load flow. The method is effective for high R/X ratios, and compared to transmission fast decoupled method, it does not require any voltage magnitude or angle assumptions, and state variables are already available in the rectangular form.

Teng and Chang in [69] propose a method, where bus voltages are used as state variables and the load flow problem is solved by employing Newton-Raphson method. In the method constant Jacobian matrix is developed and improved solution technique, to obtain the load flow solution, is applied. The time consuming procedures, such as LU factorization of the Jacobian matrix, are not necessary, and the poorly conditioned numerical problem, occurring at the factorization of the Jacobian matrix, does not exist in the proposed solution. Therefore, the method is robust and fast, and no modifications to the Jacobian building algorithm and to the solution procedure are required. Another development of Newton-Raphson method for distribution system power flow studies is proposed by Lin *et al.* in [70]. The algorithm uses a constant sparse and symmetric sub-Jacobian matrix and therefore the factorization has to be done only once.

The method based on current injection and implementation of Newton-Raphson method for unbalanced distribution system power flow solution is proposed by Garcia *et al.* in [71]. In the method the three phase current injection equations are written in rectangular coordinates. The Jacobian matrix is composed of 6×6 blocks matrices and retains the same structure as the bus admittance matrix. One more current injection based power flow method is proposed by da Costa, de Oliveira and Guedes in [72]. The authors use the optimization factor in order to correct the voltage updates at each iteration. This approach increases the robustness of the method and enables to solve power flow problems in especially stressed operating conditions.

The backward/forward methodology can be based on three different methods, e.g. the current summation method, the power summation method and the admittance summation method. The implementation of admittance summation method is proposed by Augugliaro *et al.* in [73]. The represented method differs from the standard backward/forward method because the forward phase is not present and all the system quantities (bus voltages, branch and load currents) are evaluated during the backward phase considering a scaling factor, which is the same for all variables. The scaling factor is determined at the end of the backward sweep, based on the source voltage value. The node voltages are obtained during the backward phase by means of a simple proportional factor.

Shirmohammadi *et al.* in [74] proposed compensation-based technique for weakly meshed distribution networks, where the radial parts are solved by a two-step procedure. In the first step the branch currents are calculated (backward sweep) and in the second step the bus voltages are updated (forward sweep). An improved version of algorithm, presented in [74], was proposed by Luo and Semlyen in [75] where branch power flows rather than branch currents were used. Modifications of the three-phase power flow method, based on backward/forward sweep, were proposed by Cheng and Shirmohammadi in [76]. The algorithm is able to consider dispersed generation (PV nodes), unbalanced and distributed load, voltage regulators and shunt capacitors with automatic tap controls and it is also applicable in systems with weakly meshed configuration. Zhu and Tomsovic in [77] propose an extension of the method, presented in [76], to consider also dispersed generation and nonlinear loads. The authors propose an adaptive compensation-based method, which is also implemented for dynamic simulations of the distribution system. Further developments of the algorithm in [76] and its implementation for state estimation purposes in distribution networks is discussed by Celik and Liu in [78]. Execution of unified three-phase transformer model into backward/forward method is discussed by Xiao and Yu in [79].

Thukaram, Wijekoon Banda and Jerome in [80] discuss another approach to distribution system power flow solution using the backward/forward sweep. In addition to calculating the currents in each branch and voltages at each node, the method can be extended to find an optimal feeding point in a distribution network and location of reactive power compensation, network reconfiguration etc.

Developments of distribution network analysis by Das, Nagi and Kothari are presented in [81]. They propose a forward sweeping method for radial distribution system calculation, which involves only the evaluation of simple algebraic voltage expressions without any trigonometric functions. Compared to the Newton-Raphson and fast decoupled load flow methods, the algorithm is computationally efficient, as it solves simple algebraic recursive expressions of voltage magnitude only. However, the method assumes that the distribution system is fed at only one point and the structure of the network is radial.

Haque in [82] proposes a generalised distribution network power flow algorithm suitable for distribution networks with more than one feeding node. In the algorithm the distribution network with multiple feeding sources and mesh configuration is first converted to an equivalent single source radial system. The equivalent system is obtained by isolating all feeding sources from the system, except the swing one, and opening all loops by adding some dummy buses. The effects of the isolated sources and loops are simulated by injecting appropriate power at the break points in the equivalent system. The load flow problem is solved by using the recursive equations, derived from Kirchhoff laws, which have excellent convergence pattern and can handle wide range of R and X values of branches. The algorithm is an extension of previous work of Haque [83] where a mesh network with only one feeding source was considered. Similar approach to distribution network power flow solutions was presented by Luo and Semlyen in [75] but the algorithm developed by Haque is more general, enabling to consider also the effects of shunt elements and the power injections at the break points are calculated through a reduced order impedance matrix.

Distribution network load flow algorithm based on loop-analysis method is developed and discussed by Wu and Zhang in [84]. In [85] a Z-bus based approach by Chen *et al.* is presented, in which the voltage of each bus is considered to arise from two different contributions: the specified voltage sources (PV buses) and the equivalent current sources. In [86] by Fukuyama, Nakanishi and Chiang an approach of fast distribution parallel power flow method, implemented on multi processors, is presented.

An interesting approach to load flow problem is discussed in [87] by Ferreira and de Jesus. They investigate the power flow analysis by comparing two sets of power flow equations: power flow equations based on Tellegen's theorem and conventional power flow equations. Jabr in [88] discusses and shows that the radial distribution load flow can be formulated as a quadratic optimization problem and which is efficiently solved by the interior-point methods. Implementation of the approach of object-oriented paradigm to both distribution system modelling and load flow algorithm on the emphasis on dispersed generation is proposed by Losi and Russo in [89].

Das in [90] proposes a method for considering the uncertainties of the input parameters in the power flow solution of three-phase unbalanced radial distribution systems. Based on interval arithmetic, the proposed methodology considers the uncertainties in both the load demand and the feeder parameters.

An approach of implementation of fuzzy sets theory into distribution system power flow calculations is proposed by Bijwe and Viswanadha Raju in [91]. The method is suitable for weakly meshed balanced and unbalanced distribution systems, it can simultaneously handle nonstatistical uncertainty (fuzziness) in input variables such as load model parameters, network parameters, load forecast, and bus shunts, and it is best suited for obtaining breakpoints of the fuzzy distribution of a few variables of concern identified by the crisp power flow solution. Implementation of fuzzy sets theory into distribution network power flow studies have also been proposed and discussed by Das, Ghosh and Srinivas in [92], Saric and Calovic in [93] and by Saric and Ciric in [94].

In addition, the distribution network calculations can be performed based on simplified models. Liu *et al.* in [95] propose a power flow analysis based on simplified feeder modelling. In the method three models, e.g. equivalent load model, equivalent load density model and discrete equivalent load density model, are proposed. The comparison of different methods with Newton-Raphson method is performed and discussion of the result is presented. Chen and Wang in [96] and Lo and Ng in [97] suggest two simplified approaches to the distribution system analysis. In [96] three simplified three-phase lateral models, e.g. voltage drop, line loss and hybrid model, for fast distribution system calculations are introduced. The models are developed to simulate accurately the total series voltage drop at the end of the lateral, the total copper loss of a given lateral and to simulate accurately both voltage drop and line loss, respectively. It is showed that it is possible to simplify complicated laterals to simple equivalent models in the calculation of voltage profiles and line losses with negligible error, even if there are various transformer connection schemes in the lateral or feeder. In [97] the method, where three bilateral feeder models have been developed for distribution system analysis, is presented. The presented models are formed on the assumption that a complex feeder can be simplified into an equivalent representation by simulating accurately either the feeder losses, the feeder voltage drop or both. The bilateral models enable to perform calculations regardless of the direction of power flow in the feeder.

1.3 Distribution network state estimation

Electrical network state estimation has been a research topic over forty years. Mostly the attention has been paid to the transmission network state estimation problems. The first research to solve state estimation problems in electrical power system was performed at the beginning of 1970 by Schweppe and Wildes [98] and Schweppe and Handschin [99]. Principles of the transmission network state estimation, considering state estimation methods, observability analysis, bad data detection etc. have been published in two comprehensive textbooks by Abur and Gomez Exposito [126] and Monticelly [127]. Due to the development and rise of importance of distribution networks, more interest has also been paid to methods, considering the distribution network state estimation problems. The estimation methods used in the transmission network are not directly applicable in distribution networks due to the specific characteristics of the distribution networks, e.g. radial topology, three-phase unbalanced system, high resistance to reactance ratio, very limited number of real-time measurements, etc. Therefore more profound research was needed. Research in this field has been performed for about last fifteen years. Brief overview of composed methods for distribution network state estimation is presented by Baran in [100].

Traditionally the transmission and distribution network state estimation algorithms have been studied and developed separately. From the perspective of the whole system and its optimization it may not give consistent solutions if the transmission and distribution systems are operated by the same operator. Also, due to different data source of measurements with different accuracy and redundancy, remarkable power and voltage mismatches will arise at the boundary nodes and consistent solution may not be obtained if separate algorithms for transmission and distribution networks are used. To resolve that problem a global state estimation method for the whole transmission and distribution network is proposed by Sun and Zhang in [101]. The method is based on the master-slave-splitting iterative method, which is used to solve the hybrid global state estimation problem. In the proposed method, with the introduction of the boundary fictitious measurement, the global state estimation problem of large scale is split into a transmission state estimation and lots of distribution state estimation sub-problems, which supports geographically on-line distributed computations. In order to fit different features between transmission and distribution networks, each sub-problem can be solved with a different algorithm. Based on the master-slave-splitting method, two types of detailed iterative schemes, with different characteristics, namely multi-step alternating iterative and convergence alternating iterative schemes are constructed to solve the problem.

Discussion and method of multiphase power flow and state estimation for distribution systems is covered by Meliopoulos and Zhang in [102]. The multiphase power flow model is based on fully asymmetric modelling of the power distribution system and it is used with state estimation in conjunction with synchronized measurements. The method provides an estimate of the total electric load for each distribution circuit without the requirement of knowledge of the individual loads along the circuit.

State estimation technique for real-time monitoring using the conventional weighted least squares approach and using a three-phase node voltage formulation was developed by Baran and Kelley [103]. The method uses forecasted loads from historical load data as the pseudo-measurements and it has good convergence characteristics even with very limited measurements. Li in [104] proposes another distribution network state estimation approach based on weighted least squares method. The proposed method, in addition to calculating the system state, also calculates the deviations of the bus voltages and power flow. Discussion of effect of measurement errors, correlation degree of load errors and measurement placement on the deviation of the estimated bus voltage was also presented.

The method based on weighted least squares approach with implementation of numerical observability analysis, based on triangular factorization of the gain matrix for distribution network state estimation procedures is proposed by Lu, Teng and Liu in [105]. In the algorithm, the power, current and voltage measurements are converted to their equivalent currents, and the Jacobian terms are constant and equal to the admittance matrix elements. Further development of the estimation method presented in [105] is performed by Lin and Teng in [106]. They proposed a current-based fast decoupled state estimation in rectangular form. It decouples the constant gain matrix into two identical sub-gain matrices. Compared to the preliminary algorithm, the developed approach has better performance in speed and memory usage.

Distribution network state estimation problem may be solved by using branch-based algorithms developed by Baran and Kelley [107]. The method is based on the weighted least squares approach and it is suitable for weakly meshed distribution systems which are radial or have a few loops. In the method the measurement function of the measurements on a given phase can be expressed as the function of current of that phase only, so the problem can be decoupled into three sub-problems. The method has superior performance compared to the conventional node-voltage-based methods both in terms of computational speed and memory requirements. Unfortunately, due to the treatment of current magnitude measurements and the complicated gain matrix the value of the method in real-time applications is significantly degraded. Further development of branch-based algorithm was performed by Deng, He and Zhang [108]. To resolve the deficiencies of the method, presented in [107], another development of branch-based algorithm, where the method is developed by using constant gain matrix in decoupled form (current magnitude measurements are decoupled to real and imaginary parts), was developed by Lin, Teng and Chen [109]. The described method is more robust, efficient and it needs minimal storage requirement and is suitable for real-time applications. Wang and Schulz in [110] propose another development of branch current-based algorithm. The presented algorithm uses the magnitude and phase angle of the branch current as the state variables and the load estimated values at every node based on the automatic meter reading system is used as the pseudo measurements. To improve the computational speed of the method, three phases were decoupled.

A state estimation model, which combines load models and real-time measurements, was developed by Lehtonen *et al.* in [111]. The method considers limiting technical factors, i.e. not only the load flows and currents are estimated, but also the temperatures of the power system components are assessed and compared to the critical ones. The voltage values are compared to the standard values and adequate decisions are made. The estimation of branch currents and node voltages was decomposed in the method, because the network impedance variation affects the node voltages but not the branch currents. The method is also applicable in real-time applications. The described novel method utilizes the main properties of previously performed research by Handschin [112], who studied the combination of power system measurements and load models, and a distribution load estimation algorithm by Ghosh *et al*. [113] incorporating both the statistical deviation and the correlation of loads between different customers. In [113] probabilistic extension of the radial load flow algorithm, which accounts for real-time measurements as solution constraints for state estimation purposes, is proposed. The method accounts for issues specific to distribution circuits e.g. radiality, non-normal statistical behaviour of states, load diversity, and low ratio of real-time measurements to number of states. The field test results of the algorithm, presented in the paper [113], were discussed in [114] by Lubkeman *et al*.

Roytelman and Shahidehpour in [115] propose the state estimation method oriented to using the minimum number of remote measurements available from the network. The method requires information concerning the network reconfiguration, remote measurements of voltages, active and reactive power as well as feeder currents in the distribution substations. Different statistical information is used together with real-time measurements. In the proposed method, the existing network configuration is examined by a configuration pre-screening process based on addressed references in an oriented graph. Additional information for state estimation is obtained through the prognosis of voltages and loads based on their typical pattern and from other statistical information.

An efficient and robust three-phase state estimation algorithm for application to radial distribution networks exploiting the radial nature of the network and using the forward and backward propagation scheme to estimate line flows, node voltage and loads at each node, based on the measured quantities has been developed and proposed by Thukaram, Jerome and Surapong in [116]. The method consists of observability routine to decide if the measurement set is sufficient to allow the computation of state estimation. Also bad data detection, elimination and replacement with pseudo or calculated values have been integrated to the presented method. The proposed method has no convergence problems, it is computationally very effective and it has been successfully tested by the authors on different feeders with different R/X ratios. Further developments on incorporating the network observability analysis and bad data processing methods into state estimation algorithm have been performed by Jerome in [117] where an efficient and robust method for both unbalanced and balanced three phase networks is proposed. In proposed technique the observability routine decides if the measurement set is sufficient to allow the computation of state estimate, bad measurement data is detected, eliminated and replaced by pseudo or calculated values.

Pereira, Saraiva and Miranda in [118] propose an integrated load allocation state estimation approach for distribution network. The method can be considered as fuzzy state estimation due to its ability to integrate fuzzy information. The presented algorithm enables to use as many information as possible to assign current or power values available at the substation feeders to the MV/LV substations. It is possible to include topology variables in the state vector, while preserving the continuity and differentiability of the problem, include measures defined in a qualitative way using fuzzy sets, as a way to cope with reduced numbers of telemetered measures. The use of fuzzy information gives a new degree of flexibility to this state estimation algorithm leading to more complete knowledge of the possible behaviour of the system.

In [119] by Naka *et al.* a practical distribution system state estimation method using a hybrid particle swarm optimization is used to solve the distribution network state estimation problem. The proposed method considers practical measurements in actual distribution systems and assumes that absolute values of voltage and current can be measured at the secondary side buses of substations. The hybrid particle swarm optimization can handle the non-differential and non-continuous objective function of distributed state estimation caused by nonlinear characteristics of the practical equipment present in the network. The method can estimate load and distributed generation output values at each node by minimizing the difference between measured and calculated state variables considering the practically limited measurement values in distribution systems.

An approach of using the distributed agents for distribution network state estimation is proposed by Nordman and Lehtonen in [120]. The discussed method utilizes the concept of local agents and is not based on the decomposition of conventional state estimation algorithms. The considered secondary substation agents participate in a state estimation method, which uses mainly locally available information, statistical calculations and interaction with neighbours. Area wide topology, observability and bad data analysis are performed with a token passing mechanism that is initiated and controlled by the primary substation. Presented approach of agents can be considered attractive in future distribution network with large amount of dispersed generation.

2 MONITORING OF POWER SYSTEM OPERATION

2.1 Principles of power system operation monitoring

Power system operation is a sequence between different states of the system. States of systems are characterized by state variables, e.g. voltage magnitudes, voltage angles, power flows, currents, loads, power injections etc. During the operation, i.e. moving from one state to another, the state variables vary. Monitoring the power system operation is an observation of the system behaviour in a period for which different state variables are found and analysed. Monitoring consists of forecasting and simulating different state variables and operations, considering different contingencies and possible future scenarios. The analysis of the power system operation draws back to a calculation of different steady-states because the difference of the values of state variables for a relatively long time interval is small. In this thesis the attention is paid only to the observation of the steady-state operation. No transient states and their analysis are observed.

The character and amount of data required for the calculation of power system steady-state operation depends on the purpose and period of time in observation. For example, to analyse and plan the network operation in perspective of 4…10 years long-term forecasts of load and rough estimates of electrical network and substations are considered as initial data. Based on performed calculations it is possible to compare different design approaches of the power system. In perspective of a few days to a year in advance, the objective is to plan equipment maintenance, choose adequate network configuration and appropriate settings for automatic regulators and for system automation and relay protection. For network dispatching, the calculations are necessary to understand the effect of different variations from normal operation, e.g. large load deviations, equipment failures etc. The calculations are performed in advance or momentarily after the events. For example, maintenance of one overhead transmission line may significantly alter power flows in the network, or previously calculated scenarios for different contingencies to restore the system are valuable for dispatchers who control the network operation. Security of supply and power quality must be ensured at all times. One form of analysis is retrospective analysis that indicates what should be considered in the future for successful planning and dispatching of the electrical network, but also in network design phase.

Power system steady-state operation consists of normal, critical, emergency and restorative, operation. In Fig. 2.1 transitions between different states due to control actions and due disturbances are showed. Control actions, e.g. preventive control, corrective control, emergency control and restorative control actions, are applied to move the system back to normal operation. Preventive control takes place in insecure normal operation where its purpose is to assure that the network continues its normal operation, i.e. objective of control is to ensure the fulfillment of n-1 criterion. Purpose of corrective control is to apply adequate control signals to lead the system from critical operation to normal operation, e.g. in case of transformer overload its load is switched to another transformer or to a different substation. The main purpose of the emergency control is to uphold the system or part of it in case of some large contingency. Usually this control function is applied automatically by system automation. For example, some of system load may be shed in case of emergency. Restorative control function is to restore the system normal operation after an emergency. The controls may be applied by network dispatchers or by system automation, e.g. automatic switching of load or lines after emergency.

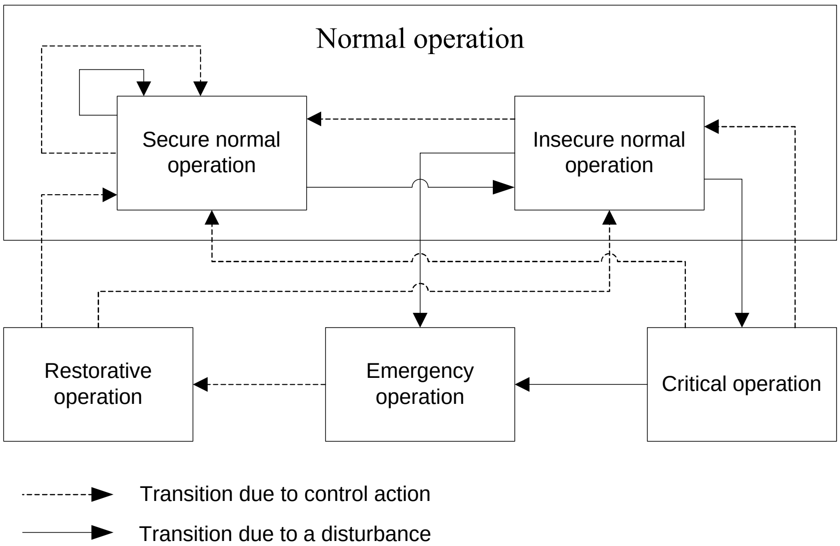

Figure 2.1. Operating states of power system

In the normal operation all state variables are slowly changing in a relatively small range. All system loads are satisfied at the specified voltage levels and frequency without violating the rated limits on any power device. The purpose of control is to monitor the operation and ensure the security of supply. Secure and insecure normal operations stand for characteristics of the system behavior to contingencies, i.e. in case of contingency the normal operation of the system is preserved or not, respectively.

During the critical operation of the power system, the state variables are also slowly changing in a relatively small range but one or some operating limits are violated, i.e. they are out of allowable limits. The purpose of control of this system operation is to assure the return to normal operation.

In the emergency operation, some of the operating limits are violated, e.g. power flows at the overhead lines, unacceptably low frequency, overvoltage etc. and the state variables are rapidly changing within large limits. In this operation the purpose of control is to locate the fault, prevent the cascading of events and automatically restore the acceptable operation. System in emergency operation can be forced to return to normal, following some corrective control measures. However depending on the severity of the emergency, some loads may be shed to alleviate a more catastrophic situation leading to a partially normal system, i.e. restorative operation.

In the restorative operation some of the loads are not met, i.e. partial or total blackout, but the operating portion of the system is in a normal state. The control purpose in this operation is to restore secure operation of the whole power system.

To understand the system operation in different contingencies implementation of analysis tools is essential, i.e. load flow and related analysis methods. For example, the loss of transmission line may result in an overloaded line, or an overvoltage conditions etc. The system may tolerate such limit violations for a short period of time. During that period corrective actions should be taken. Decisions should be based on the performed analysis. In the worst case, to uphold the system, load shedding, influence of which is previously determined, should be applied.

Steady-state calculation of the power system is one of the most frequently performed calculations for control and analysis of the system operation. It comprises 50…60% of all performed calculations as an individual task or as a part of another one, e.g. optimization of the operation, contingency analysis, small-signal stability analysis, etc. Moreover, it has an important role in planning and designing calculations. In operation planning, admissibility of different states and determination of needs for network reinforcement are determined. In contingency analysis the influence of transformer, line, generator tripping is analysed.

To perform network calculations, special software is required. In modern world two most commonly used software packages are *PSS/E* and *DIgSILENT*. Those applications enable to solve even the most complex systems. For example, for network load flow calculations it is possible to use Newton-Raphson and Gauss-Seidel methods and their modifications, e.g. *PSS/E* enables to use fixed slope decoupled Newton-Raphson, full Newton-Raphson, decoupled Newton-Raphson methods but also Gauss-Seidel and modified Gauss-Seidel methods. Solving systems with over 5000 buses is not a problem.

Information on different computational methods and system modelling can be obtained from literature. In [121] network modelling principles and explanation of different solution methods are given. Different mathematical methods for power system analysis are presented in [122] and [123]. Modelling of system elements and their analysis with different computer software is obtainable from [124], [125].

To understand the network operation, information about the observable network, especially the values of state variables are essential. The most valuable and interesting measurement values are line currents and bus voltages, transformer tap ratios, load values etc. These values are measured at the substations and transferred to control center by different information systems, e.g. *SCADA*, *AMR*, etc. *SCADA* system gathers the measurements and other state information from different substations and enables dispatchers and engineers to process and store it in a convenient format. *AMR* system collects measurements from energy meters.

For adequate system analysis and control, correct measurements and information should be used. Using different measuring devices and communication networks for data transmission may result in errors in the original data. To resolve that problem state estimators, which produce the correct state of the system, are used in the control centers.

Analysis, forecasting and simulation of the network operation may generally be solidly observed while monitoring the observable system. It consists of modelling different network components (lines, transformers, generators etc.), load modelling, composing and solving network equations etc. State estimation may be considered as a special case, where, besides finding the state variables, the measurement data is verified and adjusted.

From perspective of system analysis one may consider that in transmission networks the data redundancy is highly opposite to distribution networks where the gathering of adequate data and information on the system is somewhat complicated or even nonexistent. In the transmission network almost every substation and lines are monitored and necessary information for network control and analysis is transmitted to the dispatching centre. Based on the received information decisions for optimal network control are applied.

2.2 Methods for power system steady-state calculation

Calculation of electrical network operation requires representation of the network as a mathematical model. The model consists of network equations that are composed based on an equivalent network diagram.

2.2.1 Network equations

In case of conducting different power system studies the system state variables may be divided depending on the given purpose and searchable state variables. Composition of needed variables is generally large: voltage magnitudes and angles, active and reactive power flows at different ends of the elements, currents, active and reactive power losses, voltage drops at the elements etc. The searchable state variables are divided into independent and dependent. The independent variables are computable by solving the system of independent electrical network equations. All possible dependent variables are computable from independent state variables using the simple relations known from electrical engineering, e.g. Ohm law, Kirchhoff law etc. The composition of independent variables depends on the independent network equations selected for calculations and, conversely, the selection of independent variables determines the composition of solvable independent network equations. Nowadays the most commonly used network equations are nodal equations and accordingly the independent state variables at the node are voltage magnitudes and angles.

Let's derive the nodal equations. At first, a simple two node network is observed and afterwards the results are generalized to a network with multiple nodes. The two node network is presented in Fig. 2.2a, its equivalent diagram in Fig. 2.2b and simplified equivalent diagram in Fig. 2.2c. To facilitate the formalization of the network admittances are used. Hence, in the equivalent diagrams

$$P_i + jQ_i = P_{iG} - P_{iK} + j(Q_{iG} - Q_{iK})$$

$$\underline{y}_{ij} = g_{ij} + jb_{ij} = \frac{R_{ij}}{R_{ij}^2 + X_{ij}^2} - j\frac{X_{ij}}{R_{ij}^2 + X_{ij}^2}$$

$$g_{i0} + b_{i0} = \frac{g_{0ij}}{\mathbf{2}} + j(\frac{b_{0ij}}{\mathbf{2}} + b_{iC})$$

$$g_{j0} + b_{j0} = \frac{g_{0ij}}{\mathbf{2}} + j\frac{b_{0ij}}{\mathbf{2}}$$

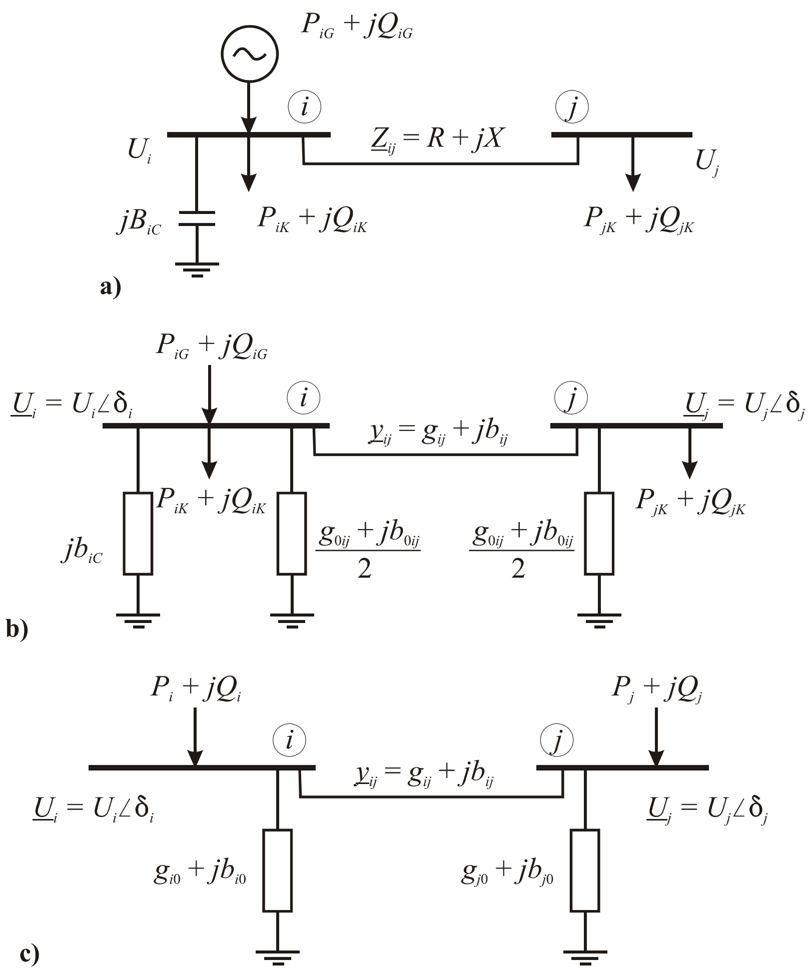

Figure 2.2. Two-node system (a), equivalent diagram of two-node system (b), and simplified equivalent diagram of two-node system (c)

Network nodal equations in current balance form are as follows. For node i Kirchhoff Current Law could be written

$$\sum_{j\in\Psi} \underline{I}_{ij} - \underline{J}_i = 0 \text{ or } \sum_{j\in\Psi} \underline{I}_{ij} = \underline{J}_i$$

where $\underline{J}_i$ is nodal current of node i

$$\underline{J}_i = J_i^{'} + jJ_i^{''} = \frac{\underline{S}_i^*}{\underline{U}_i^*} = \frac{P_i - jQ_i}{U_i^{'} - jU_i^{''}} \tag{2.1}$$

Here Ψ describes the set of nodes connected to node *i*, e.g. neighbourhood of node *i*. In Eq. 2.1 and afterwards the computational value of current, which is $\sqrt{3}$ times greater than the real value of current, is used.

Based on Fig. 2.2 we obtain

$$\underline{I}_{ij} + \underline{I}_{i0} = \underline{J}_i \tag{2.2}$$

and

$$(\underline{U}_i - \underline{U}_j)\underline{y}_{ij} + \underline{U}_i \underline{y}_{i0} = \underline{J}_i \tag{2.3}$$

After modification we obtain

$$(\underline{y}_{ij} + \underline{y}_{i0})\underline{U}_i - \underline{y}_{ij}\underline{U}_j = \underline{J}_i \tag{2.4}$$

Defining node admittances

$\underline{Y}_{ij} = -\underline{y}_{ij}$ – negative of the net admittance connected between nodes *i* and *j*

$\underline{Y}_{ii} = \underline{y}_{ij} + \underline{y}_{i0}$ – sum of admittances directly connected to node *i*.

Nodal equations for the observable two-node network for node *i*

$$\underline{Y}_{ii}\underline{U}_i + \underline{Y}_{ij}\underline{U}_j = \underline{J}_i \tag{2.5}$$

and similar equation for node *j*

$$\underline{Y}_{ji}\underline{U}_i + \underline{Y}_{jj}\underline{U}_j = \underline{J}_j \tag{2.6}$$

Eq. 2.1 and Eq. 2.5 are the nodal equations for the observable network.

For arbitrary network any node *i* is associated with many nodes, which form the neighbourhood Ψ of node *i*. Therefore, for the whole network we can write

$$\underline{Y}_{i1}\underline{U}_1 + \underline{Y}_{i2}\underline{U}_2 + ... + \underline{Y}_{ii-1}\underline{U}_{i-1} + \underline{Y}_{ii}\underline{U}_i + \underline{Y}_{ii+1}\underline{U}_{i+1} + ... + \underline{Y}_{in}\underline{U}_n = \underline{J}_i \tag{2.7}$$

$i = 1...n$

where *n* is the number of nodes in the network. The same equation in the matrix form is

$$\underline{\mathbf{Y}}\underline{\mathbf{U}} = \underline{\mathbf{J}} \tag{2.8}$$

where $\underline{\mathbf{Y}} = \mathbf{G} + \mathrm{j}\mathbf{B}$ – node admittance matrix

$\underline{\mathbf{U}}, \underline{\mathbf{J}}$ – vector of node voltages and node currents.

Thereat

$$\underline{\mathbf{J}} = (\underline{\mathbf{U}}_d^*)^{-1} \cdot \underline{\mathbf{S}}^*(\underline{\mathbf{U}}) \tag{2.9}$$

where $\underline{\mathbf{U}}_d$ is diagonal matrix of nodal voltages.

As it is possible to notice, the elements of the node admittance matrix $\underline{\mathbf{Y}}$ are

- mutual admittance of nodes i and j – admittance of a connecting branch between the nodes with opposite sign $\underline{Y}_{ij} = -\underline{y}_{ij}$. If the branch between nodes i and j does not exist, then $\underline{Y}_{ij} = 0$
- self admittance of node i – sum of all the branch admittances connected to the node i (i.e. shunt branches) $\underline{Y}_{ii} = \sum_{j \in \Psi} \underline{y}_{ij}$.

Based on the previous equations, it is possible to derive real equations in the power balance form

$$P_i = U_i^2 G_{ii} + U_i \sum_{j \in \Psi} U_j (G_{ij} \cos \delta_{ij} + B_{ij} \sin \delta_{ij}) \tag{2.10}$$

$$Q_i = -U_i^2 B_{ii} + U_i \sum_{j \in \Psi} U_j (G_{ij} \sin \delta_{ij} - B_{ij} \cos \delta_{ij}) \tag{2.11}$$

$i = 1...n$

where $\underline{Y}_{ii} = G_{ii} + jB_{ii}$ and $\underline{Y}_{ij} = G_{ij} + jB_{ij}$

2.2.2 Solution methods

Calculation of electrical network steady-state operation is based on finding unknown independent system state variables, e.g. nodal voltages and voltage angles, by solving the network equations. The network equations are nonlinear and therefore they are solved using iterative methods by defining initial estimates of voltage and angle. Usually the values of initial estimates are the results from some other, previously found calculation or are flat initial estimates, where the value of voltage is nominal voltage and value of angle is zero. Searchable complex values $\underline{U}_i$, $(i = 2,...,n)$ and the number of solvable complex equations is equal to the number of independent nodes $n-1$. For the benefit of computational speed it is preferable to use the real equations instead of complex equations. Then, there are $2(n-1)$ searchable real variables, whereof it is needed to solve the system consisting of $2(n-1)$ real equations. Dependent node is named as slack node, where voltage magnitude and voltage angle is given and the produced active and reactive power is determined by power balance. As the numeration is principally arbitrary, the slack node is marked with index 1. If the independent system state variables are known, then the rest of the state variables, e.g. power flows, currents, power and voltage losses etc., are found using known relations based on Ohm and Kirchhoff laws. The number of dependent state variables depends on the purpose of the computations.

In order to calculate the electrical power network steady-state operation different methods could be used. Applicable methods are different to the extent of computations, speed of convergence and to the required amount of memory. Solution reliability, sensitivity to initial estimates, complexity of the algorithm and compatibility with other calculations is also an important issue. Solution reliability means a possibility to find a solution (iteration process converges) even in case of complex networks or states. Compatibility with other calculations is important if the steady-state calculation is a part of a larger study, e.g. state optimization, stability analysis etc.

In practice, Gauss-Seidel and Newton-Raphson methods and their modifications are preferably used for network state calculations. *Gauss-Seidel* method is simple and has been used for a long time. It is based on iteratively solving the nodal equations system given in a form of current balance

$$\underline{\mathbf{YU}} = \underline{\mathbf{J}} \tag{2.12}$$

and nodal current expression

$$\underline{\mathbf{J}} = (\underline{\mathbf{U}}_d^*)^{-1} \cdot \underline{\mathbf{S}}^*(\mathbf{U}) \tag{2.13}$$

with the following scheme:

$$\underline{U}_i^{(k)} = f(\underline{U}_1^{(k)}, \underline{U}_2^{(k)}, ..., \underline{U}_{i-1}^{(k)}, \underline{U}_{i+1}^{(k-1)}, ..., \underline{U}_n^{(k-1)}),\ i = 2,...,n \tag{2.14}$$

Here the corrected value of voltage $\underline{U}_i^{(k)}$ at *k*-th iteration is found based on the previously found voltage value. The rest of the voltage values are found similarly. Iterations are repeated as long as the convergence criterion is fulfilled

$$\max_i \left| \underline{U}_i^{(k)} - \underline{U}_i^{(k-1)} \right| \le \underline{\varepsilon}_U \tag{2.15}$$

where $\underline{\varepsilon}_U$ is given calculation accuracy of voltages.

After the convergence of voltage calculations the slack node power is found

$$\underline{S}_1 = \underline{U}_1 \underline{J}_1^* = \underline{U}_1 \sum_{j \in \Psi} \underline{Y}_{1j}^* \underline{U}_j^* \tag{2.16}$$

If the purpose of the calculations was to find only the voltages then the calculation is finished, but if other state variables are needed then power balance conditions at the nodes should be checked

$$\max_i \left| \Delta \underline{S}_i \right| = \max_i \left| \underline{S}_i(U_i) - \sum_{j \in \Psi} \underline{Y}_{ij}^* \underline{U}_j^* \right| \le \underline{\varepsilon}_S \tag{2.17}$$

where $\underline{\varepsilon}_S$ is a given accuracy of power balance. If the condition is fulfilled, then the calculation of independent state variables (voltages) is finished, otherwise the needed accuracy of voltage calculations is increased

$$\underline{\varepsilon}_U = \frac{\underline{\varepsilon}_U}{l} \tag{2.18}$$

where *l* is a number 2...10, and it is returned back to the voltage calculations.

Usually, the acceleration of convergence is incorporated when the Gauss-Seidel method is used. It is based on principle, that before using the calculated estimates at the next step it is adjusted as follows:

$$\underline{U}_i^{(k)} = \underline{U}_i^{(k-1)} + \omega \cdot (\underline{U}_i^{(k)} - \underline{U}_i^{(k-1)}),\ i = 2...\ n \tag{2.19}$$

where ω is acceleration factor, value of which is usually taken as 1,3...1,7. The optimal value of acceleration factor depends on the nature of the network and it is usually found by way of probation. The use of acceleration enables to enhance the speed of convergence even two times.

The advantages of Gauss-Seidel method are:

- small memory requirement
- volume of calculation in an iteration is small
- speed of convergence and solution reliability do not depend on initial estimate of voltage
- algorithm is simple
- it enables to observe the reasons for unconvergence and possible problematic parts of the network.

The disadvantages of the Gauss-Seidel method are:

- slow convergence – achievement of necessary accuracy may require hundreds of iterations, especially near stability limit
- number of necessary iterations increases when the number of network nodes increases
- relatively long computational time due to slow convergence
- relatively bad solution reliability, especially near stability limit
- the method does not allow negative series admittances nor branches with small impedance.

Due to the simplicity of Gauss-Seidel method, it is still used but its field of application is decreasing. Sometimes the Gauss-Seidel method is used in conjunction with Newton-Raphson method to estimate the initial estimates closer to the real solution.

Newton-Raphson method and its modifications are effective methods and nowadays they are widely used. Let's observe nonlinear equation system

$$\mathbf{b} = \mathbf{f}(\mathbf{x}) \tag{2.20}$$

where **b** and **x** – *n*-dimensional vector of given and searchable variables
f – *n*-dimensional vector function.
It can also be written

$$b_i = f_i(x_1,...,x_n) \quad i = 1,...,n \tag{2.21}$$

Let $\tilde{\mathbf{x}}$ be the solution of the equation and $\mathbf{x}^{(0)}$ its estimate. Let $\mathbf{f}(\mathbf{x})$ be differentiable around solution $\tilde{\mathbf{x}}$, like it is in case of electrical network. Then it is possible to develop the equation system $\mathbf{f}(\mathbf{x})$ into Taylor series at point $\mathbf{x}^{(0)}$

$$\mathbf{f}(\mathbf{x}) = \mathbf{f}(\mathbf{x}^{(0)}) + \frac{\partial \mathbf{f}}{\partial \mathbf{x}}\Big|_{\mathbf{x}^{(0)}} (\mathbf{x} - \mathbf{x}^{(0)}) \text{ + higher-order terms} \tag{2.22}$$

Let's mark the equations system partial derivative matrix, e.g. Jacobian as

$$\mathbf{A}(\mathbf{x}) = \frac{\partial \mathbf{f}}{\partial \mathbf{x}} \tag{2.23}$$

that in expanded form is

$$\mathbf{A}(\mathbf{x}) = \begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \dots & \frac{\partial f_1}{\partial x_n} \\ \frac{\partial f_2}{\partial x_1} & \frac{\partial f_2}{\partial x_2} & \dots & \frac{\partial f_2}{\partial x_n} \\ \dots & \dots & \dots & \dots \\ \frac{\partial f_n}{\partial x_1} & \frac{\partial f_n}{\partial x_2} & \dots & \frac{\partial f_n}{\partial x_n} \end{bmatrix} \tag{2.24}$$

Without considering the higher-order components, we obtain the linearized task

$$\mathbf{b} = \mathbf{f}(\mathbf{x}) = \mathbf{f}(\mathbf{x}^{(0)}) + \mathbf{A}(\mathbf{x}^{(0)})(\mathbf{x} - \mathbf{x}^{(0)}) \tag{2.25}$$

As actually the task is nonlinear, we define the vector $\mathbf{x}^{(1)}$ so, that

$$\mathbf{b} = \mathbf{f}(\mathbf{x}^{(0)}) + \mathbf{A}(\mathbf{x}^{(0)})(\mathbf{x}^{(1)} - \mathbf{x}^{(0)}) \tag{2.26}$$

If $\mathbf{A}(\mathbf{x}^{(0)})$ is not degenerated, e.g. $\det \mathbf{A}(\mathbf{x}^{(0)}) \neq 0$, then

$$\mathbf{x}^{(1)} = \mathbf{x}^{(0)} + \left[\mathbf{A}(\mathbf{x}^{(0)})\right]^{-1}\left[\mathbf{b} - \mathbf{f}(\mathbf{x}^{(0)})\right] \tag{2.27}$$

e.g. generally

$$\mathbf{x}^{(k+1)} = \mathbf{x}^{(k)} + \left[\mathbf{A}(\mathbf{x}^{(k)})\right]^{-1}\left[\mathbf{b} - \mathbf{f}(\mathbf{x}^{(k)})\right],\ k = 0, 1, 2, \dots \tag{2.28}$$

Differently

$$\mathbf{x}^{(k+1)} = \mathbf{x}^{(k)} + \Delta\mathbf{x}^{(k)} \tag{2.29}$$

where correction $\Delta\mathbf{x}^{(k)}$ is found by solving the linearized equation system

$$\mathbf{A}(\mathbf{x}^{(k)})\Delta\mathbf{x}^{(k)} = \mathbf{b} - \mathbf{f}(\mathbf{x}^{(k)}) \tag{2.30}$$

To check the convergence of the method a nodal power balance criterion is used

$$\max_{\mathrm{i}}\left|P_i^a - P_i\right| \leq \varepsilon_P \quad \text{and} \quad \max_{\mathrm{i}}\left|Q_i^a - Q_i\right| \leq \varepsilon_Q \tag{2.31}$$

where $\varepsilon_P, \varepsilon_Q$ are given calculation accuracies of active and reactive power balance (usually 0,01...0,1 MW and MVAr).

The nature of the method is illustrated in Fig. 2.3.

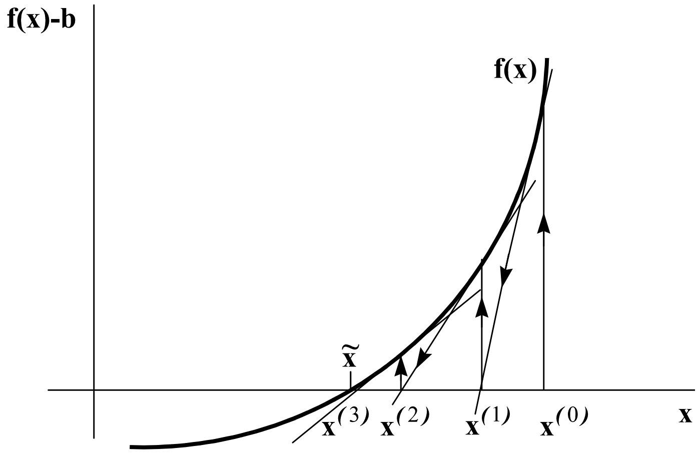

Figure 2.3. Illustration of the Newton iterative process

The advantages of the Newton-Raphson method are

- convergence is very fast – needed accuracy is obtained by less than five iterations, usually by one to three iterations
- speed of convergence does not depend on network dimensions
- relatively fast calculation speed – due to very fast convergence
- relatively small necessity of memory due to implementation of sparse matrix techniques, but it is higher than Gauss-Seidel method
- considerably higher solution reliability than Gauss-Seidel method
- good compatibility with optimizing calculations
- possibility to consider negative series admittances.

Disadvantages of the method are

- very large amount of calculations in one iteration, because the elements of the Jacobian should be recalculated on every iteration and network linear equations must be solved
- sensitivity to initial approximation of voltage.

Newton-Raphson method has additional specificity, namely the Jacobian has a lot of zero elements, due to the fact that one network node is only connected to another node, not to all network nodes. Matrix that consists of a lot of zero elements is named sparse matrix. Implementation of those types of matrices to network calculations requires large amount of memory and a lot of time is spent on calculations with zeros. To increase the efficiency of calculations sparse matrix techniques are used, but in that case the algorithm of the calculation will be more complex. Despite the disadvantages, the Newton-Raphson method is the most preferable method. Nowadays different modifications of Newton-Raphson method prevail.

One of the modifications of Newton-Raphson method is *fast decoupled method*. The base for the method is the fact that resistance of transmission network overhead lines and transformers is remarkably smaller than their inductance. In addition, angle difference between the ends of lines and transformers is small and is not exceeding 30º, in most cases it is below 10...15º. Therefore, it is possible to simplify network equation so, that they decouple into two independent equation systems. To speed up the iteration process other techniques are applied. As a result, more effective algorithm compared to Newton-Raphson base method is obtained. Its disadvantage is its incompatibility with medium and low-voltage networks, where the basic requirements for method implementation are not fulfilled.

If we presume an additional simplification, that all admittances are trifling and all the voltages are equal to nominal voltages, then we obtain a *steady-state linear model*, e.g. *DC model*, where active power values are linearly expressed through voltage angles. Reactive power values are not observed. Linear model is used to calculate the active power distribution rapidly, for example, in case of contingency analysis, when comparing different scenarios during network planning calculations etc.

Modern steady-state calculation programs also try to assure the admissibility of the state, e.g. convergence solution, when all contingencies are fulfilled. For example, the transformer taps are adjusted so that the voltage values at the network check points are in given limits. If the voltage value, during the iteration process at some check points, goes out from the permitted limits, then in the process of iteration, the nearest transformer tap value is adjusted until the voltage value is within the allowed limits. In generator nodes, reactive power values are calculated after every iteration. At those nodes where it exceeds the limits, the reactive power is fixed at exceeding limit and the voltage magnitude is released. It changes the nature of the node, i.e. it is now a load node, where active and reactive power values are given and voltage magnitude and angle should be found. If the active power value is increased at the slack node, then surplus or deficit of active power is divided between the rest of the nodes and the iteration process is continued until the active power value at the slack node is within allowable limits. If the reactive power limit is exceeded in the slack node then the slack node is substituted with some other generation node, slack node given voltage is changed within allowable limits or the reactive power generation or consumption is increased appropriately by switching shunt capacitors or shunt reactors. Therefore, the program tries to model the modern automation devices, to obtain the operation where all contingencies are satisfied. That is not always possible and interference by engineers is then required.

2.3 Power system state estimation

Power system state estimation has gained an important role for understanding and operating the system. Almost every power system control centre has a possession of a state estimator. Methods and development of state estimation have remarkably matured over four decades. Comprehensive overview and clarification of power system state estimation principles and methods, network topology processing, bad data processing techniques, robust state estimators etc. are observed in [126], [127]. Over the decades, numerous research papers have been presented in the area of power system state estimation and application (Chap. 1.3).

The main purpose of the state estimation is to filter defective data, eliminate incorrect measurements and produce reliable state estimates. With a proper redundancy of measurements, it is possible to eliminate the effect of bad data and allow the temporary loss of measurements without significantly affecting the quality of estimated values. The measurements used for network calculations and analysis are substantially obtained through monitoring systems e.g. *SCADA* and they may include relatively large errors or may be insufficient due to errors in transducers, communication channels etc. In addition, state estimation enables, to a certain extent, to determine the power flows in parts of the network that are not directly metered. The refined information obtained from state estimation is used for power system contingency analysis, optimal power flow, input for dispatcher training simulator etc.

Dependent on the level of consideration of network dynamics, it is possible to distinguish two main state estimation possibilities e.g. static and dynamic state estimation. The static state estimation is based on the data corresponding to a certain time moment, i.e. information on one certain moment is used and no earlier data or results from previous estimations are utilized. Previously collected data is additionally used in the dynamic state estimation. It also presumes that the operational dynamic model is available. Although the dynamic state estimator is principally more effective, the experience shows that the static state estimator makes less and smaller errors, especially in case of rapid change of network operation and in occurrence of systematic measurement errors. Therefore, static state estimators are more frequently used.

State estimators may be basically considered as filters between raw measurements obtained from the network and the application functions that require the reliable data on the current state of the system (Fig. 2.4). Typically the state estimators include the following functions:

- topology processor
- observability analysis
- state estimation solution
- bad data processing
- parameter and structural error processing.

The topology processor gathers status data about different commutation equipment e.g. circuit breaker etc., and configures the diagram of the system. As a result it generates a bus/branch model of the power system. Usually the model includes all buses within the observable area but additionally it may include selected buses from a neighbouring system in order to build up and update the external system model.

The possibility to obtain state estimation solution for entire system based on available set of measurements is determined by observability analysis. Furthermore, it enables to identify the unobservable branches and detect unobservable islands in the system if any exist. The analysis of network observability utilizes the graph theory as it relates to networks, their associated equations and solutions. The observability analysis is performed prior to state estimation to determine whether enough real-time measurements are available to make state estimation possible and, if not, which part of the network contains states which can still be estimated, as well as where pseudo-measurements can be added to improve observability [128], [129], [130]. Transmission networks are usually designed to be fully observable, but temporary unobservability may still occur due to unforeseen network topology changes or failures in the telecommunication system.

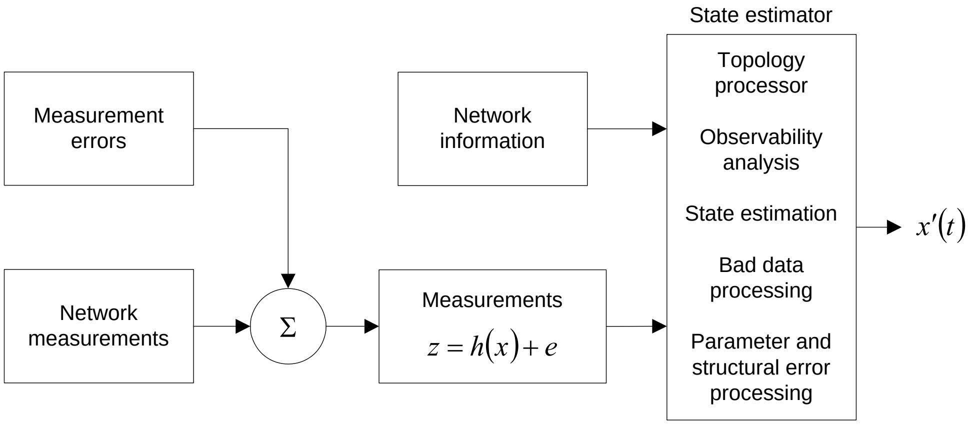

Figure 2.4. Principal scheme of state estimation

The objective of the state estimation is to determine the optimal estimate for the system state, which includes complex bus voltages in the entire power system, is based on the network model and on the gathered measurements from the system. Best estimates for all the line flows, loads, and generator outputs are also provided as a result of state estimation.

The measurements may contain errors due to various reasons e.g. wrong meter connection, malfunction of devices, errors in telecommunication channels etc. One of the significant tasks of the state estimators is to process and eliminate bad data from the measurement. It should detect the existence of gross errors in the set of measurements and in case of enough redundancy in the measurement configuration also identify and eliminate bad measurements [131], [132], [133]. The basic techniques that are normally used for detecting and identifying bad data are $J(x)$-test, the r^n-test, and error estimation techniques. These techniques can be successfully used for processing both single and multiple noninteracting bad data.

As a result of parameter and structural error processing it is possible to estimate various network parameters, e.g. transmission line model parameters, tap changing transformer parameters, shunt capacitors or reactor parameters etc. In addition, detection of structural errors in the network configuration and identification of erroneous breaker status is possible if sufficient measurement redundancy exist.

Mathematical description and principles of state estimation algorithm are as follows. The state estimation measurement model relates measurements to state variables:

$$\mathbf{z} = \mathbf{h}(\mathbf{x}) + \mathbf{e} \tag{2.32}$$

where $\mathbf{x}$ is the n vector of the true states (unknown), components of which are voltage angles and modules

$\mathbf{z}$ is the m vector of measurements (known), components of which are usually active and reactive power and also bus voltage measurements

$\mathbf{h(x)}$ is the m vector of linking measurements to state variables, depending on network configuration and measurement composition

$\mathbf{e}$ is the m vector of random errors

m is the number of measurements

n is the number of state variables.

The purpose of state estimation is to obtain the estimation $\mathbf{x}'$ of vector $\mathbf{x}$ by minimizing the vector of measurement residuals. The measurement residual vector is defined as

$$\mathbf{r} = \mathbf{z} - \mathbf{h}(\mathbf{x}') \tag{2.33}$$

Thus $\mathbf{r}$ is the difference between the measured values $\mathbf{z}$ and the corresponding estimated values $\mathbf{z}' = \mathbf{h}(\mathbf{x}')$. To minimize the residuals $\mathbf{r}$ a weighted least squares method is usually used, which requires the minimization of the objective function

$$\mathbf{J}(\mathbf{x}') = [\mathbf{z} - \mathbf{h}(\mathbf{x}')]^{\mathrm{T}} \cdot \mathbf{W} \cdot [\mathbf{z} - \mathbf{h}(\mathbf{x}')] = \min \tag{2.34}$$

Matrix $\mathbf{W}$ is a diagonal matrix whose elements are the measurements weights. Most commonly, $\mathbf{W}$ is based on the reciprocals of the variance of measurement errors

$$\mathbf{W} = \mathbf{R}_z^{-1} = \begin{pmatrix} \sigma_1^{-2} & & & & \\ & \sigma_2^{-2} & & & \\ & & \cdot & & \\ & & & \cdot & \\ & & & & \sigma_m^{-2} \end{pmatrix} \tag{2.35}$$

where $\mathbf{R}_Z$ is the measurement covariance matrix.

To obtain the optimal conditions objective function $\mathbf{J}(\mathbf{x}')$ should be differentiated. At the minimum, the first-order optimality conditions will have to be satisfied. These can be expressed in compact form as follows:

$$\mathbf{g}(\mathbf{x}) = \frac{\partial \mathbf{J}(\mathbf{x}')}{\partial \mathbf{x}} = -\mathbf{H}^{\mathrm{T}}(\mathbf{x}') \cdot \mathbf{W} \cdot [\mathbf{z} - \mathbf{h}(\mathbf{x}')] = 0 \tag{2.36}$$

Where

$$\mathbf{H}(\mathbf{x}) = \left.\frac{\partial \mathbf{h}(\mathbf{x})}{\partial \mathbf{x}}\right|_{\mathbf{x}=\mathbf{x}'} \tag{2.37}$$

Expanding the non-linear function $\mathbf{g}(\mathbf{x})$ into its Taylor series around the state vector $\mathbf{x}^k$ yields:

$$\mathbf{g}(\mathbf{x}) = \mathbf{g}(\mathbf{x}^k) + \mathbf{G}(\mathbf{x}^k)(\mathbf{x} - \mathbf{x}^k) + \ldots = \mathbf{0} \tag{2.38}$$

Neglecting the higher order terms leads to an iterative solution scheme known as the Gauss-Newton method as shown below:

$$\mathbf{x}^{k+1} = \mathbf{x}^k + \mathbf{\Delta x}^k$$
$$\mathbf{G}(\mathbf{x}^k) \cdot \mathbf{\Delta x}^k = \mathbf{g}(\mathbf{x}^k)$$

hence

$$\mathbf{x}^{k+1} = \mathbf{x}^k - \left[\mathbf{G}(\mathbf{x}^k)\right]^{-1} \cdot \mathbf{g}(\mathbf{x}^k) \tag{2.39}$$

where k is the iteration index

$\mathbf{x}^k$ is the solution vector at iteration k

$$\mathbf{G}(\mathbf{x}^k) = \frac{\partial \mathbf{g}(\mathbf{x}^k)}{\partial \mathbf{x}} = \mathbf{H}^{\mathrm{T}}(\mathbf{x}^k) \cdot \mathbf{W} \cdot \mathbf{H}(\mathbf{x}^k)$$
$$\mathbf{g}(\mathbf{x}^k) = -\mathbf{H}^{\mathrm{T}}(\mathbf{x}^k) \cdot \mathbf{W} \cdot \left[\mathbf{z} - \mathbf{h}(\mathbf{x}^k)\right]$$

G(**x**) is named gain matrix. The matrix is sparse, positive definite and symmetric, provided that the system is fully observable.

Besides static state estimator more advanced methods for state estimation have been developed over the years, e.g. estimation based on multiple scans of measurements (tracking and dynamic methods), fast decoupled state estimator, numerically robust state estimators etc. Further information on these methods could be found in [126], [127].

3 MONITORING OF DISTRIBUTION NETWORK OPERATION

3.1 Principles of distribution network operation monitoring

In the power system, the purpose of distribution networks is to distribute electrical energy from transmission substations to consumers. Distribution networks consist of different types of lines (overhead lines and cables), different voltage levels (medium- and low-voltage), different network configurations (radial and meshed) etc. All these factors influence the distribution network security of supply, economical efficiency and quality of power. In [134] and [135] comprehensive overview of distribution network and its operation is presented.

Monitoring of distribution network operation consists of determining and observing actual configuration and operation of the distribution network. For this purpose, network steady-state and short-circuit calculations for past, present and future are used. Therefore adequate modelling of the system components and loads are important. To assure the system security and minimize network losses optimization calculations are needed. It is important to guarantee the power quality.

Distribution network consists of large amount of lines, transformers, switches and other equipment, which form calculation perspective from thousands of branches and buses. As the distribution network is operating with radial configuration, the main problem in the network calculation is not to solve the network equations but to determine the correct and actual network topology and other initial information. It is possible to speak of network model, which is formed based on static (type and co-ordinates of the lines, switches etc.) and dynamic information (voltages, powers, etc.), obtained from network information system, dispatching system, etc.

The base for calculating the distribution network operation is the actual configuration of the network that is determined as a result of topological analysis. Positions of switches are obtained from operational scheme or from dispatching system. Necessary measurement data is also obtained from dispatching system. The data received through dispatching system is not always reliable and therefore the actual operation should be estimated. In the estimation process the mathematical model of busloads, that gives the expected values of load and probable deviations, is used. Those busload models are also a base for forecasting loads enabling to analyse the future operation of the network. Probable deviations of load due to stochasticity or weather conditions are considered. Based on the current and voltage values obtained from the estimation it is possible to verify the network state. In addition to steady-state calculations, short-circuit currents are founded and their acceptance is analysed. It is possible to implement an indicative system so that when the predetermined limits for network operation are exceeded, noticeable information is presented. Final suitability of the network operation is still decided by the network operator, who has additional information about the network and its operation. Network operator may also have previously performed calculations for different conditions, e.g. different contingencies, load deviations etc. and therefore complementary information is available to assess and analyse the network operation.

The nominal voltage levels of distribution network are varying between countries. Usually the networks, where nominal voltage value is below 110 kV are considered as distribution networks. Distribution networks are divided into medium-voltage and low-voltage networks, where the nominal voltage is in the range of 1 kV up to 35 kV and below 1 kV, respectively. For example, in Estonia the nominal voltage levels used in medium-voltage distribution networks are 6, 10, 15, 20 and 35 kV.

From the viewpoint of the nature of consumers the distribution networks may be divided into industrial, urban and rural networks. Industrial networks are mainly inner networks of industries, through which they are distributing their required electricity. Urban distribution networks are characterized by their complex configuration, large number of consumers and cable lines. On the other hand, rural networks are dispersed, with relatively small number of consumers and long overhead lines.

Network configuration is directly related to the required level of security of supply. From the perspective of security, the consumers are divided into three groups. The first group is formed by the customers, who require supply from two different sources, e.g. hospitals, industries with complex technological processes, etc. Consumers who require connections form two different supply units, where the reserve is manually connected, e.g. most of the industries, are part of the second group. The third group consists of customers, e.g. home consumers, who are connected to the network by one radial line.

The configuration of the distribution network, determined by the connection between different branches and buses may be as following:

- simple radial networks
- branching radial networks
- mesh networks.

Mesh networks are complex systems with many closed circuits and in use at networks, e.g. transmission networks, where high reliability is needed, usually from voltage 110 kV and over. Typically, the distribution networks are built as mesh networks but they are operating with radial configuration because system relay protection and automation, compared to the mesh network are simpler and cheaper. In these networks, disconnection points, that separate the network into different feeders, are used. As an exception, some parts of the distribution network may be operated as mesh system, especially in case of large power flows and when high reliability is required. The network built as closed system enables to reserve the supply and increase the security of supply.

A simple radial network, where the power is distributed to the consumer by only one line, is used where low reliability is accepted. Branching radial networks are mostly common in rural areas, where inhabited area is small and electricity is distributed over long distances. Simple mesh networks operating as open radial networks are used both in rural and urban areas. Examples of different configurations of distribution network are presented in Fig 3.1.

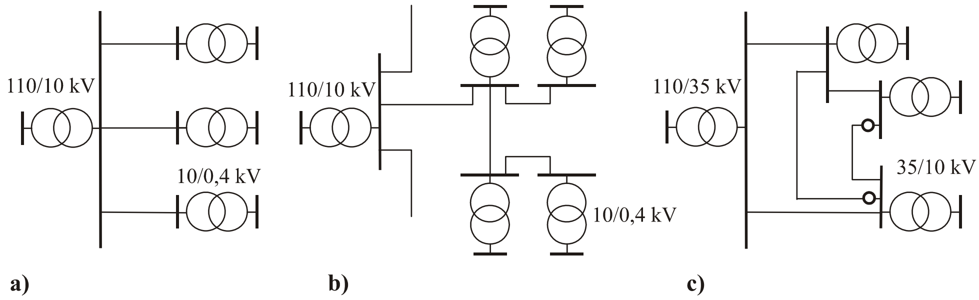

Figure 3.1. a) Simple radial distribution network, b) branching radial distribution network and c) mesh network with possible disconnection points

In Fig. 3.2 an example of distribution network feeder is presented. The number of feeders exiting from HV/MV substation may reach up to twenty or more depending on the location and type of consumers in the region. Commonly the feeder has many branches and connections to other feeders. The branching points are usually located at pole-mounted or unit substations, which are equipped with disconnectors enabling to change the network configuration due to maintenance or fault in the network. At the distribution substations the power is transformed from medium-voltage to low-voltage, e.g. from 10 kV to 0,4 kV.

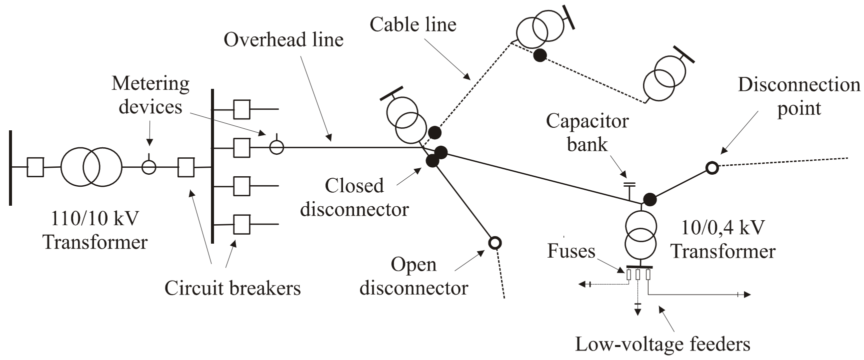

Figure 3.2. Configuration of distribution network feeder

The HV/MV substation consists of high and medium-voltage switchgear, transformer, metering devices and other equipment. Transformer nominal power is usually at the range of 5…63 MVA and it is typically equipped with on-load tap changer. Voltage regulation may be in the range of ±9×1,78%. Metering devices located at the transformer secondary side are needed for measurement purposes and for relay protection. Also each of the feeders may be monitored.

Distribution network protection is relatively simple. Medium-voltage feeders are usually protected with maximum current and earth-fault protection, low-voltage feeders only with maximum current protection. Medium voltage distribution network feeder circuit breakers have relay protection and they can be remotely switched. In the low-voltage network mainly fuses and knife switches are used. Low-voltage feeder protection is performed by fuses or automatic breakers.

Distribution network feeder may be based on overhead line or cable depending on the location and required level of reliability. Usually urban networks are always cable networks and rural networks are generally overhead line networks. Feeder may also include capacitor banks to regulate the voltage and compensate reactive power in the network. The loading of a distribution feeder is inherently unbalanced because of the large number of unequal single-phase loads.

To guarantee the normal operation of network equipment and ensure the quality of power and security of supply the distribution network operation should be monitored and controlled. It is necessary to measure different network state variables, to perform reactive power compensation, voltage regulation and adequate system dispatching.

In distribution network different state variables are measured, e.g. voltages, currents, active- and reactive powers and energies. Furthermore, power quality measurements, where specific quality parameters, e.g. harmonics, voltage asymmetry, voltage dips etc. are determined and assessed. Measurements are obtained from different parts of the distribution network (Fig. 3.3). The lower the voltage level the less measurements are performed and information about the network is obtained. For example, in HV/MV substations, the busbar voltages and all feeder currents, active and reactive power values are measured in real time and transmitted through dispatching system to control centre, but at the distribution substations no online measurements are available. Power quality measurements are collected from different places using both stationary measurement devices but also portable devises, which are especially efficient at consumer connection points. Distribution network power quality can also be monitored through telemeasurements.

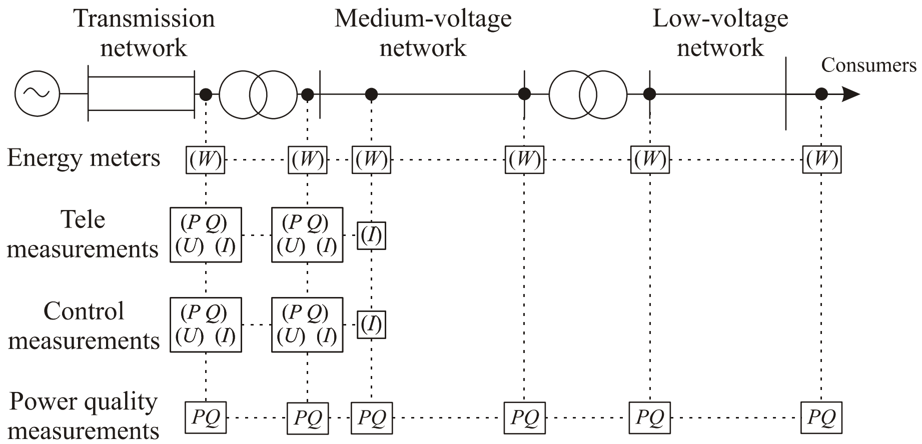

Figure 3.3. Measurements at the distribution network

From the perspective of purpose, the measurements can be divided into technical and commercial measurements. The purpose of technical measurements is to monitor the equipment operation and support distribution network control in normal and abnormal conditions. Commercial measurements are needed to determine electrical energy distributed from the network to consumers.

To measure, transmit and process the measurement data, different information systems are used. The most comprehensive measurement system is a part of dispatching system (*SCADA*). Here the data collected by substation automation system is transmitted through communication systems to control centre, where the data is stored and converted to the appropriate form for network control and planning purposes.

The described measurement systems do not comprise all the distribution network substations. Most of the distribution network substations are equipped with measurement devices that are not connected to the *SCADA* system and their data is not saved or transmitted. To receive information on state variables at unobservable substations the control measurements on exact days of a year, e.g. two typical days in summer and winter, are performed. The control measurements are performed on a regular weekday maximum morning load period, at night minimum period and in the evening maximum load period. At weekends night minimum and evening maximum load periods are under observation.

Compensation of reactive power is an important issue in the distribution networks. Reactive power is consumed by induction motors, transformers, converters etc. It is known that the transmission of reactive power through the network is not reasonable because it increases the energy losses and voltage drop. Therefore, it is rational to generate the reactive power near consumers. The effect of reactive power compensation is presented in Fig. 3.4.

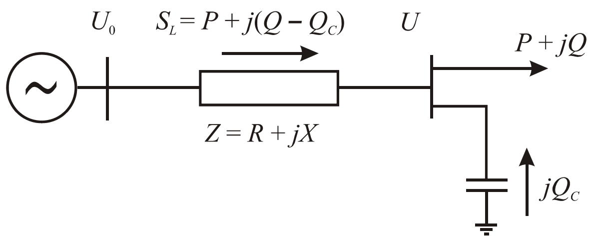

Figure 3.4. Reactive power compensation principle

Compensating devise Q_C is connected to the consumer terminals and the power delivered through a distribution line is

$$\underline{S}_L = P + j(Q - Q_C) \tag{3.1}$$

and respectively the power loss and voltage drop can be expressed as

$$\Delta P = \frac{P^2 + (Q - Q_C)^2}{U_n^2} R \tag{3.2}$$

$$\Delta U = \frac{PR + (Q - Q_C)X}{U_n} \tag{3.3}$$

The losses are minimal when $Q_C = Q$, i.e. all the necessary reactive power is produced at the consumption location. Overcompensation should also be avoided, because then current in the line and consequently the losses are increasing and the stability of load may be jeopardized.

The reactive power is traditionally characterized by a ratio between active power and apparent power, e.g. $\cos \varphi = P/S$. Sometimes the ration between reactive power and active power, e.g. $\tan \varphi = Q/P$, is used. For example, the $\tan \varphi$ value in Estonian distribution network is in the range of 0,2…0,5.

The compensating devices used in the distribution networks are dominantly capacitor banks. When selecting the capacitor bank, different requirements should be considered, e.g. appropriate location, regulation possibilities, structure, relay protection, one or three phase compensation etc. When installing capacitor banks in the network the existence of harmonics in the network should be determined. In case of harmonics, measures to avoid voltage resonance between capacitor capacitance and network inductance should be applied. In addition to harmonics, possible increase of network voltage level should also be considered.

Voltage regulation in the distribution network is one of the most important tasks for the system operators when monitoring and controlling the network operation. All electrical devices connected to the distribution network require supply voltage that is within certain specified limits. Due to existence of voltage drop, the voltage level at customers near the transformer is higher than at customers that are located at the end of the distribution feeder. The reactive power compensation devices and voltage regulators also influence the voltage level. The problem has both technical and economical background. The operation of appliances is optimal at nominal voltage level. If the allowable limit of voltage is too large then excessive expenses are caused to the consumer. On the other hand keeping the voltage at narrow limits requires additional costs from the network operator.

Voltage at the consumer terminals U is first of all dependent on the transformer tap ratio and voltage drop

$$U = \frac{U_0 - \Delta U_\Sigma}{k} \tag{3.4}$$

where U_0 is the secondary voltage of supply transformer

ΔU_Σ is the total voltage drop from the supply substation to the consumer

k is the distribution transformer tap ratio.

The voltage level is primarily regulated by changing the transformer tap ratios. Two types of transformers, one with on-load tap changer and other without that are in use. The on-load controllable transformers are in use at HV/MV substations and non-controllable transformers in the distribution substations. Distribution substation transformer taps are changed seasonally. Automatic voltage regulator devices are used to regulate capacitor banks and transformers with on-load tap changers. The optimal level of voltage in the distribution network is achieved by selecting the correct regulation settings for main substation transformers and correct taps for distribution substation transformers.

Distribution network operation can also be controlled and influenced by different voltage regulating devices based on power electronics, i.e. concisely called as *FACTS* devices. These devices are usually more common in transmission networks, where they are used for voltage and power regulation and for power system stability enhancement. In recent years, these modern devices have also been installed in distribution networks to regulate voltage and consequently improve power quality at customer connection points or at various distribution network substations. Both serial (*dynamic voltage restore, DVR*) and shunt compensation (*static synchronous compensator – STATCOM*) possibilities have been implemented. Good overview and principles about *FACTS* and their use in electrical networks is presented in [136], [137] and [138].

3.2 Modelling of distribution network

Performing calculations and analysis on a distribution network requires the representation of the network. All elements in the network must be modelled and corresponding equivalent diagram parameters must be found. More profound information about distribution network modelling and analysis can be obtained from [134], [139], [140]. In this chapter the theoretical principles of modelling different network devices are presented.

3.2.1 Electrical lines

In electrical networks, the electrical lines are usually modelled with π-model. In distribution network simplifications are made (Fig. 3.5). Line parameters are total line series impedance $\underline{Z} = R + jX$ and total line shunt admittance $\underline{Y} = G + jB$. In π-model, half of the shunt admittance is lumped at each end of the line. Total line series impedance may be calculated through line resistance r and reactance x per kilometre and through length of the line l. Similarly, total line shunt admittance can be expressed through line conductance g and susceptance b per kilometre and through length of line. Hence,

$$\underline{Z} = (r + j\omega L)l = (r + jx)l \tag{3.5}$$

$$\underline{Y} = (g + j\omega C)l = (g + jb)l \tag{3.6}$$

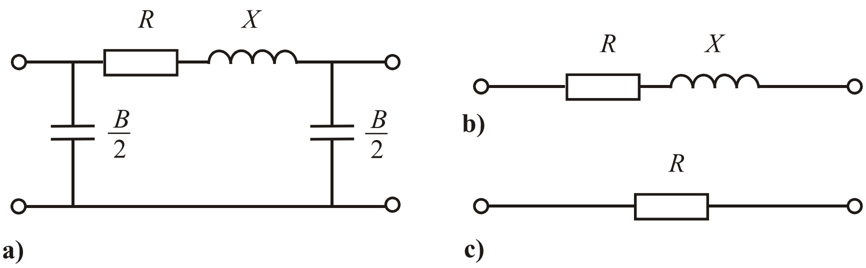

Figure 3.5. Equivalent circuit diagrams representing distribution network lines, a) overhead line 110 kV, b) overhead line $U_N \leq 35$ kV and c) cable line $U_N \leq 10$ kV

Values of resistance r (Ω/km) per kilometre can be obtained from handbooks or product catalogues. These values correspond to the fixed temperature ϑ_0 (for example +20 ºC). If necessary, it is possible to convert the fixed temperature to temperature ϑ as

$$r_{\vartheta} = r\left[1 + 0.004(\vartheta - \vartheta_0)\right] \tag{3.7}$$

Line reactance is inductive and it depends on the location of line conductor and its geometrical dimensions. If we presume that line conductors are symmetrically positioned, then it is possible to use approximate equation and determine line reactance per kilometre as

$$x = 0{,}144 \log \frac{D_k}{r_j} + 0{,}0157 \quad \Omega/\text{km} \tag{3.8}$$

where $D_k = \sqrt[3]{D_{AB} D_{BC} D_{CA}}$ is the mean geometrical distance between phases

r_j is the radius of conductor.

Line reactance is relatively insensible to measures D_k and r_j, therefore in rough calculations for MV network overhead lines and cables the value of reactance may be taken as 0.4 Ω/km and 0.1 Ω/km, respectively.

Line conductance g per kilometre corresponds to active power losses present due to incomplete insulation and corona. Component g is usually considered from voltage level 330 kV and over.

Line susceptance b per kilometre is contingent due to capacitance between conductors and between conductors and earth. Assuming that the phase conductors are located symmetrically, it is possible to determine the overhead line susceptance per kilometre by

$$b = \frac{7.58 \cdot 10^{-6}}{\log \frac{D_k}{r_j}} \quad \text{S/km} \tag{3.9}$$

The consideration of susceptance of the line becomes important at higher voltage levels. In overhead lines with voltage $U_N \leq 35\,kV$, the susceptance is usually disregarded. Therefore, line equivalent diagram is simplified (Fig. 3.5b).

Cable parameters are usually given at product catalogues or handbooks. Compared to overhead lines the distances in the cable between phases are relatively smaller and therefore the reactance of cable is small and susceptance big. Hence, in case of cables with small cross-section and $U_N \leq 10\,kV$, the reactance is often neglected (Fig. 3.5c). Susceptance of cable lines should be considered at cables with voltage level of 35 kV. Conductance is usually not considered in case of cable lines.

3.2.2 Transformers

Modelling of distribution network transformers is a complicated task due to existence of two or more windings with different nominal voltages. In addition, transformer connection group and possible quadrature voltage control, that change the value of transformer ratio to complex, should be noticed and considered. However, in distribution networks, only real part of the transformer ratio could be considered because only transformer having the same connection may be switched in parallel operation.

To model transformers it is rational to use *Γ*-model (Fig. 3.6a). In distribution network calculations it is possible to employ additional simplifications. In series circuits only resistance and reactance is observed and the shunt circuits are replaced with constant no-load active and reactive power (Fig. 3.6b). In the equivalent diagrams also ideal transformer, comprising the transformer ratio, is presented. All transformer parameters are moved to primary side.

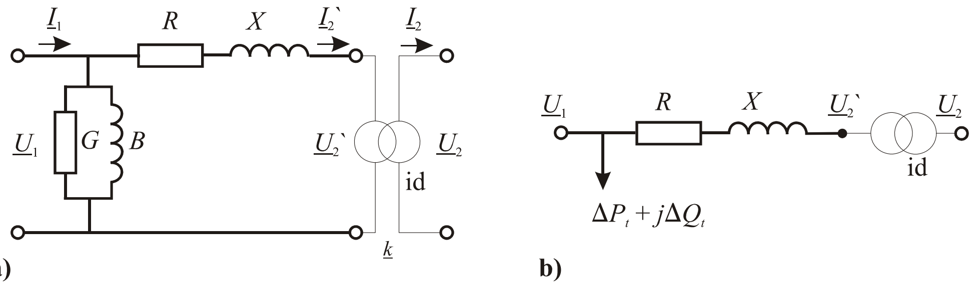

Figure 3.6. Transformer Γ-model a) equivalent diagram and b) simplified equivalent diagram

The parameters R and X presented in Fig. 3.6a and Fig. 3.6b describe the total reactance and inductance of transformer windings, whereat the secondary winding reactance and inductance values are moved to the primary side by multiplying the components by the impedance scaling factor

$$R = R_1 + R_2' = R_1 + \left(\frac{U_{1n}}{U_{2n}}\right)^2 R_2 \tag{3.10}$$

$$X = X_1 + X_2' = X_1 + \left(\frac{U_{1n}}{U_{2n}}\right)^2 X_2 \tag{3.11}$$

where, U_2' and I_2' are the values of secondary voltage and current moved to the primary side of the transformer

$$U_2' = \frac{U_{1n}}{U_{2n}} U_2 \tag{3.12}$$

$$I_2' = \frac{U_{2n}}{U_{1n}} I_2 \tag{3.13}$$

Different parameters of the transformers are presented in handbooks and product catalogues. In addition to transformer nominal power S_n, primary and secondary winding nominal voltages U_{1n} *and* U_{2n}, also transformer no-load losses ΔP_t, load losses ΔP_k, no-load current as a percentage from nominal current $I_{t\,\%}$, short-circuit voltage $u_{k\,\%}$ or the corresponding short-circuit reactance value $Z_{k\,\%}$, may be presented Hence, the transformer equivalent diagram parameters can be obtained using the following formulas

$$R = \frac{\Delta P_k U_n^2}{S_n^2} \tag{3.14}$$

$$X = \frac{u_{k\%} U_n^2}{100 S_n} = \frac{Z_{k\%} U_n^2}{100 S_n} \tag{3.15}$$

$$G = \frac{\Delta P_t}{U_n^2} \tag{3.16}$$

$$B = \frac{I_{t\%} S_n}{100 U_n^2} \tag{3.17}$$

Here the voltage U_n is the nominal voltage of the winding where the parameter is moved. For examples, in Fig. 3.6 the parameters values are moved to primary voltage $U_n = U_{1n}$.

Transformer no-load active and reactive power are considered as constant and active power part as equal to no-load losses ΔP_t. No-load reactive power component is determined as

$$\Delta Q_t = \frac{I_{t\%} S_n}{100} \tag{3.18}$$

Transformer complex ratio considering the connection group m of the transformer or corresponding real component k may be obtained as

$$\underline{k} = \frac{U_{1n}}{U_{2n}} e^{-jm\frac{\pi}{6}} \tag{3.19}$$

$$k = \frac{U_{1n}}{U_{2n}} \tag{3.20}$$

In the network where three different nominal voltages are present it is rational to use three winding transformers, where three windings of different voltages are located on the same core. Also autotransformers are used. To model three winding transformers and autotransformers the star equivalent diagram, where the shunt admittances are connected to the centre point of the star, is usually used. For sufficient accuracy those shunt admittances may be brought out to transformer terminals or only consider constant no-load losses independent on voltage (Fig. 3.7).

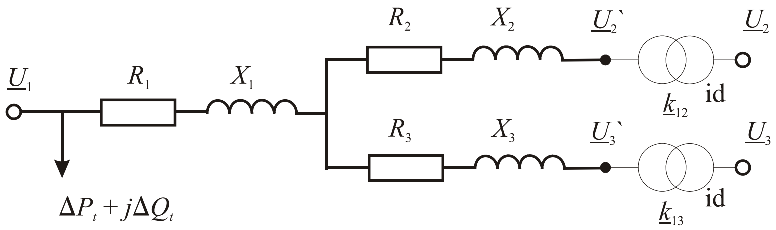

Figure 3.7. Simplified equivalent diagram of the three winding transformer

In transformer catalogues and handbooks usually data on transformer nominal power S_n, winding voltages U_{1n}, U_{2n}, U_{3n}, no-load losses ΔP_t, $\Delta I_{t\%}$, load losses $\Delta P_{k\,12}$, $\Delta P_{k\,13}$, $\Delta P_{k\,23}$ and short-circuit voltages $u_{k\%\,12}$, $u_{k\%\,13}$, $u_{k\%\,23}$ of a pair of windings, respectively, are presented. Impedances R_{12}, R_{13}, R_{23} and X_{12}, X_{13}, X_{23}, corresponding to load losses and short-circuit voltages, are found similarly compared to two winding transformer. Considering that $R_{12} = R_1 + R_2$, $X_{12} = X_1 + X_2$ etc. it is possible to obtain the parameters of three winding transformer equivalent diagram as follows

$$R_1 = \frac{R_{12} + R_{13} - R_{23}}{2},\ R_2 = \frac{R_{12} + R_{23} - R_{13}}{2},\ R_3 = \frac{R_{13} + R_{23} - R_{12}}{2} \tag{3.21}$$

$$X_1 = \frac{X_{12} + X_{13} - X_{23}}{2},\ X_2 = \frac{X_{12} + X_{23} - X_{13}}{2},\ X_3 = \frac{X_{13} + X_{23} - X_{12}}{2} \tag{3.22}$$

Shunt admittances G and B and reactive power loss ΔQ_t are found in a similar way as in case of two winding transformer.

3.2.3 Compensating devices

In electrical networks the series and shunt capacitors and shunt reactors are used for voltage regulation and series reactors for limiting short-circuit current values. Generally, when calculating the network steady-state operation, the status of capacitors and reactors is unavailable because it depends on the values of network bus voltages. The result is obtained through iterations.

Shunt capacitors and reactors are presented in the equivalent network diagram as shunt admittances, whereat the conductance is taken as zero

$$\underline{Y} = 0 + jB \tag{3.23}$$

$$B = -\frac{Q_n}{U_n^2} \tag{3.24}$$

where Q_n is the nominal reactive power of capacitor ($Q < 0$) or reactor ($Q > 0$)
U_n is network nominal voltage.

In the equivalent network diagram the series capacitors and series reactors are presented as series impedances, whereof active component is taken as equal to zero. The value of reactance in capacitors and reactors is as follows

$$X_C = -\frac{10^6}{\omega C} \tag{3.25}$$

$$X_L = \frac{U_n x_{\%}}{100\sqrt{3} I_n} \tag{3.26}$$

where C is the capacitance of the capacitor, μF
$x_{\%}$ – reactor reactance
U_n , I_n – reactor nominal voltage and current.

3.2.4 Loads

Distribution network loads are considered as the total load of certain customers connected to the network. The load that is represented as active power and reactive power value consists of loads of different appliances, e.g. induction motors, lighting and heating devices, converters, etc. and losses in the connecting network. Even if the load value composition were known exactly, it would be impractical to represent each individual component as there are usually thousands of such components in the total load supplied by a power system. Therefore, load representation in system studies is based on considerable amount of simplifications and different load modelling methods are used, depending on the exact purpose.

Generally, the consumers' active and reactive power values are changing in time and are dependent on voltage and frequency, e.g. $P=P(t,f,U)$ and $Q = Q(t,f,U)$. In practice, the load dependencies on each factor offer more interest. Time dependency of load, presuming that frequency and voltage values are constants is considered as load curve. According to load periodicity it is possible to name load curves, e.g. yearly, seasonal, daily etc. Load curves on the regular weekdays may be quite similar and different on the weekends. Different consumer groups have different load curves. In the handbooks it is possible to find type load curves that can be used in the calculations and planning purposes.

Loads on a distribution feeder can be modelled as wye connected or delta connected. The loads can be three-phase, two-phase, or single-phase with any degree of unbalanced and can be modelled as constant active and reactive power, constant current, constant impedance or any of the combinations [140]. If, for example, yearly consumed energy is known then it is possible to assess the maximal load by

$$P_m = \frac{W}{T_m} \tag{3.27}$$

where W is the yearly energy and T_m is the utilisation period at maximum capacity, i.e. fictive time that corresponds to the yearly energy indented to the maximum load P_m. It is also possible to use another approximative method, i.e. Velander equation

$$P_m = k_1 W + k_2 \sqrt{W} \tag{3.28}$$

where coefficients k_1 and k_2 are dependent on consumers. Coefficient values for different group of consumers are presented in handbooks.

For more precise calculation of distribution network operation the influence of voltage and frequency to load, i.e. voltage and frequency characteristic curve $P(U,f)$ and $Q(U,f)$, respectively, must be considered. Usually the frequency in the system is constant and may differ from normal value at large system contingencies. Therefore, characteristics by voltage offer more interest.

For calculation of distribution network steady-state operation different load modelling methods have been implemented. For example, the load is modelled using the typical curves, the load is considered as independent from voltage, the loads are modelled as bus currents independent on voltage and the loads are modelled as constant impedances or as admittances [134]. In case of induction motors and other type of special loads, e.g. electric-arc furnaces etc., more dynamical aspects should be considered. In this thesis approach of mathematical modelling of load for distribution network monitoring is used. Comprehensive overview and principles of mathematical model of load can be obtained from Chapter 4.

3.3 Distribution network steady-state calculation

Configuration of the distribution network is radial. In most cases the network is built as a mesh network, but considering the technical and economical aspects it is usually working with an open configuration. Therefore, most often distribution network steady-state calculations are performed for radial network. On the other hand, mesh network calculation methods, e.g. Gauss-Seidel and Newton-Raphson method, could be used in case of finding the optimal disconnection points in the network.

Calculation of radial distribution network steady-state operation using the conventional Gauss-Seidel or Newton-Raphson method is not effective. It is more rational to employ simple two step iteration method, e.g. backward-forward sweep method. There, in the first step, power losses and power flows in the lines, starting from the end of the line, are calculated and afterwards, bus voltages, starting from HV/MV substation MV bus, where the voltage value is considered as known, are found (Fig. 3.8).

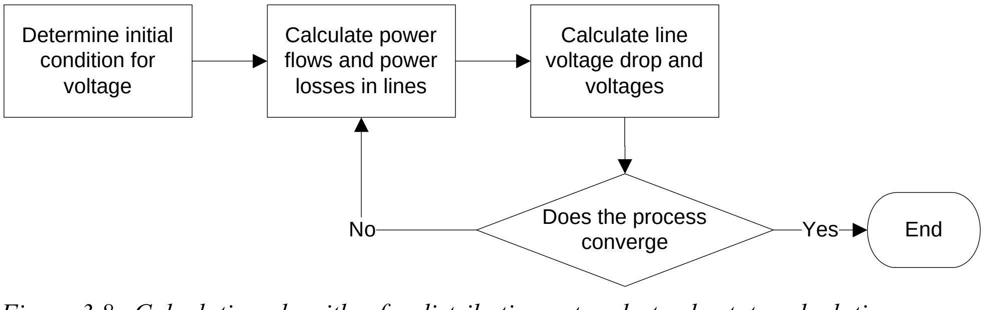

Figure 3.8. Calculation algorithm for distribution network steady-state calculations

The initial conditions for voltage may be the value of nominal voltage, or some bus voltage value obtained from earlier calculations, which is similar to observable operation. The described algorithm usually converges in 2…5 iterations, but considering the roughness of initial data, usually one iteration is sufficient, especially in case of low voltage network calculations. In approximate calculations power losses are usually disregarded.

To perform network calculations adequate network models should be composed. In medium voltage networks the following simplifications are made

- line shunt conductances are neglected
- transformers shunt conductances are neglected, iron losses are considered when calculating network active power losses and energy losses
- in case of cables their inductive reactance is neglected.

When calculating the voltage values, the imaginary component $\Delta U_i^{"}$ of voltage loss $\Delta \underline{U}_i$ is neglected and the value of voltage drop is considered as equal to real component of the voltage loss $\Delta U_i = \Delta U_i^{'}$, because in distribution network the angel δ between the input and output voltage vectors of whatever network elements is small (Fig. 3.9a). When for *i*-th part of the line (Fig. 3.9b), voltage U_i and active power P_i and reactive power Q_i at the beginning of the *i*-th line, but also line parameters R_i and X_i, are known, then voltage loss in the line may be expressed as

$$\Delta \underline{U}_i = \underline{I}_i \underline{Z}_i = (I_i' - jI_i'')(R_i + jX_i) = (I_i'R_i + I_i''X_i) + j(I_i'X_i - I_i''R_i) \tag{3.29}$$

which real part is considered as equal to voltage drop

$$\Delta U_i \cong (I_i'R_i + I_i''X_i) \tag{3.30}$$

By multiplying and dividing the result with voltage U_i, we obtain the equation with active and reactive power

$$\Delta U_i = U_i - U_{i+1} \cong \frac{P_i R_i + Q_i X_i}{U_i} \tag{3.31}$$

In the backward loop, when the voltage values are given and power flows are to be found, active power and reactive power losses in the *i*-th line segment are found

$$\Delta P_i = \frac{P_{s\,i+1}^2 + Q_{s\,i+1}^2}{U_{i+1}^2} R_i, \tag{3.32}$$

$$\Delta Q_i = \frac{P_{s\,i+1}^2 + Q_{s\,i+1}^2}{U_{i+1}^2} X_i \tag{3.33}$$

and active power and reactive power values at the beginning of the line segment

$$P_i = P_{s\,i+1} + \Delta P_i \tag{3.34}$$

$$Q_i = Q_{s\,i+1} + \Delta Q_i \tag{3.35}$$

Here active power $P_{s\ i+1}$ and reactive power $Q_{s\ i+1}$ are, respectively, the sum of loads and branch active power and reactive power exiting from node $i + 1$.

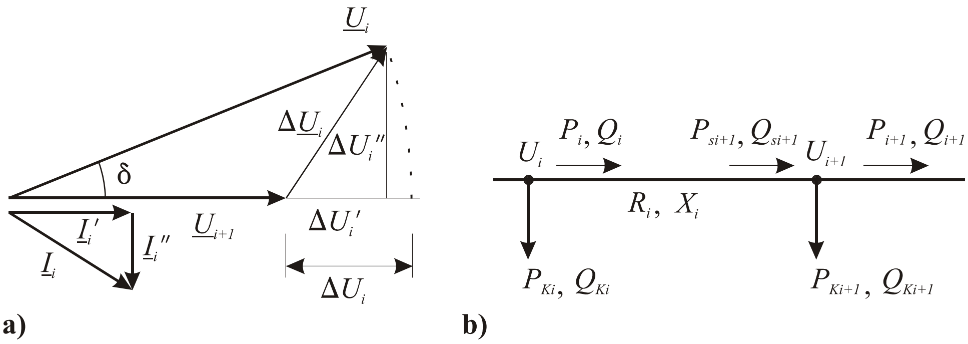

Figure 3.9. a) Voltage loss and voltage drop in the network element and b) line segment representation for calculations

Distribution network calculation applications enable additional possibilities for network analysis. First of all, the necessary voltage level in certain substations is secured by selecting suitable transformer tap rations and capacitor bank capacity values. For determination of relay protection settings also short-circuit calculations are performed. It is possible to perform calculations for some certain moment, operation or as continuous calculations for longer period, observing the change of the network operation and influence of different parameters. The changes of loads are described with type curves or with simplified load models. More comprehensive results may be obtained if accurate model of load, e.g. mathematical model of load, is used (Chp. 4). Furthermore, it is possible to compose dynamic models of state variables, which enable to forecast and analyse state variables considering their timely changes, temperature dependency and stochasticity (Chp. 5).

3.4 Optimal operation of distribution network

The purpose of the distribution network is to supply consumers with electrical energy of high quality with minimal costs. The optimization criterion in distribution networks is usually the minimization of network losses. Nevertheless, requirements for quality and security of supply are also important.

Measures for minimizing network losses may be divided as follows

- technical measures
- commercial measures
- organisational measures.

Technical measures are associated with construction or reconstruction of electrical installations. Hence, additional investments are required. The purpose of most of the technical measures is not to minimize losses, but to increase the transfer capacity of the network and enhance system security and power quality. Minimization of losses is a concurrent effect. The most important technical measures are regulation of voltage levels, replacement or building of additional lines and transformers, reactive power compensation.

The purpose of commercial measures is to enhance measurement and settlement systems. It comprises various activities, from inspection raids to employing signal systems to voltage transformer fuses at the substations.

Organisational measures are related to the optimization of network configuration and operation. These measures do not require additional investments. The most effective organisational measures are

- control of distribution network voltage level
- optimizing the location of distribution network disconnection points
- optimizing the operation of distribution network transformers.

In addition, it is possible to decrease network losses through minimizing substation auxiliary power requirements, symmetrisation of load at the low voltage networks, decreasing the influence of harmonics, coordination of demand side management, developing the technical maintenance procedures etc.

Control of distribution network voltage level is one of the main possibilities to decrease the network losses. Since the main part of power losses are load losses, which are inversely proportional to square of the voltage, then in order to employ the power losses minimization criterion it is necessary to use the highest allowable voltage level. Approximately, the rise of the voltage level by 1% decreases the network losses by 2%. On the other hand the rise of voltage level is constrained by the requirements to insulation and by the requirement to assure acceptable voltage level for consumers. Optimization of distribution network voltage level consists of optimizing the regulation characteristics of transformers with on-load tap changer and appropriate selections of taps of the transformers without on-load tap changer. In the presence of capacitors, their tap regulation is an additional optimization criterion. The criterion for optimization is the deviation limit of voltage level at the consumers' connection point during the maximal and minimal load. To satisfy the above mentioned criterion, it is required that the voltage at the HV/MV substation MV busbars should be maximal during the maximal load period and minimal during the minimal load period. Tuning of distribution network voltage level control system is usually started by optimizing the voltage level at 6…15 kV networks and afterwards at 20…35 kV HV/MV substations.

Disconnection points in the distribution network should be selected in the way that the network operation would be optimal. Depending on the operation of distribution network possible locations of disconnection points may vary in time. However, the disconnection points are relatively rarely changed. To solve the optimization problem two principally different methodologies are employed. In the first approach, energy losses corresponding to different locations of disconnections points are calculated, whereat the optimal solution is where the losses are the smallest. For the above described method many algorithms for determining optimal disconnection points, where the disconnection points are varied according to a certain strategy, are developed. The second approach is to calculate the optimal network operation for mesh network, which is formed when all the disconnection points are closed. Afterwards the disconnection points are selected so that the open operation of the distribution network is as close as possible to the optimal operation determined before. The positive effect obtained from optimizing network disconnection points is more noticeable in urban networks, where the nature of load pattern and therefore the optimal disconnection points are more constant. In the country networks the loads have seasonal characteristics and therefore disconnection points should be changed more frequently.

To increase network reliability distribution network MV/MV and MV/LV substations comprise two or more transformers. To save energy in those substations, it is rational to disconnect those transformers, which are working in the low load conditions. As a result the total iron losses of transformers are reduced, but on the other hand copper losses are increased due to the increase of load of working transformer. Therefore, the disconnection of transformers is rational if the decrease of iron losses is bigger that the increase of load losses. Disconnection of transformers for a few hours is not considered rational.

3.5 Distribution network control

3.5.1 Principles of distribution network control

Control of distribution network ensures the electrical network operation that guarantees the customers with supply of high reliability and quality and is acceptable from the point of view of service of the network. In normal operation it means to follow and adjust the planned operation and control of switchings and other operations. In case of some contingency, network relay protection and other automatics operate depending on their settings. Afterwards network control by dispatchers, the purpose of which is to dismantle the consequences of contingency and restore the normal operation and secure the supply to all consumers, is performed.

Distribution network operation is observed by network dispatchers, seven days a week, 24 hours a day. The tasks of network dispatchers are to

- ensure and control distribution network normal operation
- restore normal operation after contingencies
- prepare and control planned maintenances and repairs
- co-operate with other control centres.

Network operation should correspond to normal network scheme, which assures the distribution of the electrical energy with minimal losses and assures the security and quality of supply. Optimal operation of distribution network is obtained by suitable selection of disconnection points and by rational regulation of network voltage. Security of supply is guaranteed by reliable network configuration, where appropriate automation devices, e.g. automatic reclosing relay etc., are used where necessary. Besides mesh network configuration may be used.

Voltage level in the distribution network is regulated at the HV/MV and MV/LV substations using mainly transformers and capacitor banks. Network dispatcher is observing the voltage value at the transformer low-voltage side and when necessary regulates the voltage through supervisory control systems. The purpose is to hold the voltage level at allowable limits. The voltage value is one of the considerable indicators of power quality.

Sometimes it is necessary to overload the network equipment. Overvoltages are also possible. For a short time, the overload is allowed in purpose to start reserves or restore the system operation after contingencies. For example, the current values at the overhead lines may exceed the nominal values of 20% with duration of not more than one day, whereas it is not allowed to exceed the allowed current limit at specific ambient temperature. In general, the cables are not allowed to be overloaded. When necessary the cable overload limits are determined by considering the cable type and its placement conditions. Overloading transformers is determined by transformer manufacturer. In addition, the relay protection settings should be considered.

One of the main tasks of distribution network control is to eliminate possible emergencies and failures. During the contingencies the dispatchers should

- prevent the enlargement of the emergency
- eliminate a threat to humans and animals and secure the equipment
- locate and disconnect the damaged equipment or part of the network
- guarantee the normal operation of the rest of the network
- organise the repair or replacement of the damaged equipment
- restore the supply and network normal scheme after repairs.

Information about the contingencies is, first of all, received through *SCADA*, which transmits information concerning positions of the switching devices, but also information on operation of relay and automation devices. Information on operation state variables and on the existence of substation auxiliary is also delivered. If the values of state variables are outside of the allowable limits then the *SCADA* generates the alarm message. Additional information may be obtained from consumers.

The main contingencies to be considered in the distribution network are tripping of overhead lines or cables, one phase earth faults, malfunction of switching devices, transformer tripping, etc.

Restoration of supply is started after the initial information of the contingency is obtained and analysed. In the first stage the supply is restored to those lines or substations that deliver power to large consumer groups or regions. Necessary switchings are performed via *SCADA*. Possible switchings are to transfer of load to reserve transformer or line, reclosing of line, etc. As a result of the switchings the supply will recover completely or partially. If there are some substations without telecontrolled switches then the operating personnel is included in the fault restoration process.

Besides the control of normal operation and restoration of the system from different contingencies, the network dispatchers should control and lead the preparations for maintenance and repairs in the network. The dispatchers' task is to perform necessary switchings, fill the documentation and restore the normal network scheme after the maintenance work has been completed.

3.5.2 Applications for distribution network control

Distribution network control depends largely on available information offered by information systems. For example, the following information systems may be used:

- network information system (*AM/FM*)
- geographical information system (*GIS*)
- dispatching system (*SCADA*)

- distribution management system (*DMS*)
- customer information system (*CIS*)
- energy meter reading (*EMR*)
- electricity quality and load (*EQL*)
- electrical load monitoring (*ELMO*)
- distribution energy management (*DEM*).

Network information system (automated mapping and facilities management system) manages information about the network elements (lines, transformers, switches etc.). In the geographical information system all information concerning maps and graphical representation of the network is handled. *SCADA* system handles the electrical network dispatching functions. Network calculations, management of faults and defects are part of distribution management system. Consumption and consumer information is managed by customer information system. Distant reading of energy meters to determine the real energy exchange is handled through energy meter reading system. It is also complemented by electricity quality and load system to determine and handle power quality issues. Load monitoring system *ELMO* (Chap. 6), based on data received form energy meter reading and customer information system, enables to model the distribution network loads for forecasting and analysis. For energy market support, distribution energy management system, which manages information of market participants, gives reports, assesses network losses, etc., is used.

From the point of view of distribution network monitoring and maintenance, the most important applications are *SCADA* and *DMS*. For example, in Estonian distribution network, *SCADA* and *DMS* are handled by *ABB MicroSCADA* and *Tekla Xpower*, respectively. *Xpower* consists of information on equipment actual state but also on their dynamics (past, future). That information is necessary when planning maintenance and renovation, and also when performing network calculations. *SCADA* system collects information from substations, which is necessary for network control and transmits it to control centre where the data is analysed and appropriate user interface is composed. It is possible to control switches, change the settings of regulators and relay protection devices remotely. For example, in Estonian distribution network 450 substations out of 18 000 are observed by *SCADA*. The rest of the substations and their information are handled by network information management system *Xpower*.

In Fig. 3.10 an example of Estonian distribution network unified information system is presented. The system consists of network management, maintenance and operational control information systems, i.e. network management system, information management system *Xpower* and dispatching system *MicroSCADA*. Network management system handles all the static information about the network. Dynamical data on the observable part of the distribution network is collected and analysed by dispatching system. Data on the unobservable part of the distribution network is processed by *Xpower*, which, first of all, have the network support function, e.g. distribution management system (*DMS*) function. Network maintenance, operational planning and network planning functions are applied to the extent which is not employed by network management system.

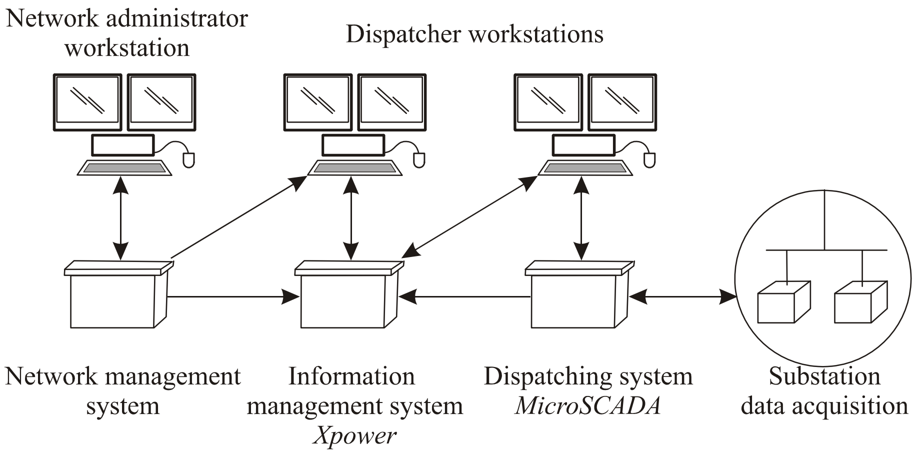

Figure 3.10. Unified information system of Estonian distribution network

Information management system *Xpower* consists of different modules which, for example, are used to manage network assets, plan network development and maintenances etc. One of the important modules of the information management system *Xpower* is *DMS* module which offers various possibilities to calculate radial distribution network steady-state operation, short-circuits and earth faults. It is also possible to calculate mesh network steady-state operation and fault currents. It is possible to perform calculations for one certain state or for continuous states.

With *DMS*, it is possible to perform calculations for low-, medium- and high-voltage networks. The calculations are based on the load model enabling to determine loads for each of the consumer type, based on the simplified load models. Therefore, it is possible to calculate network states for whatever time period starting from one hour to a year. Based on the information received from *CIS* it is possible to forecast network busloads and calculate the network considering the needs for network renovation or long-term development.

In addition to calculation of voltage and current values the calculation of network steady-state operation consists of determining other important values, e.g. equipment loading, power and energy losses and their cost etc.

Calculations of short-circuit currents are necessary for network planning but also for checking network relay protection settings. For example, in low-voltage networks the short-circuit calculations enable to analyse the selectivity of fuses, in medium-voltage networks it is possible to determine the lines that do not thermally sustain short-circuit currents. For those lines it is possible to simulate the conditions to increase their sustainability by changing relay protection settings or network configuration. In distribution network control it is possible to quicken the determination of short-circuit location and check the functioning of relay protection in exceptional conditions.

Earth currents in the medium voltage network may be calculated for an isolated neutral system and also for an impedance earthed system. The neutral may be earthed through arc-suppression coil or through large impedance. The calculation results give information on operation of relay protection devices and enable to check the adequacy of network earthing.

Dispatching system may be considered as the base for modern distribution network control. *SCADA* system is a distributed heterogeneous system, consisting of levels:

- local area systems
- data transfer systems
- central systems.

In Fig. 3.11 an example of principles of distributed dispatching system is presented.

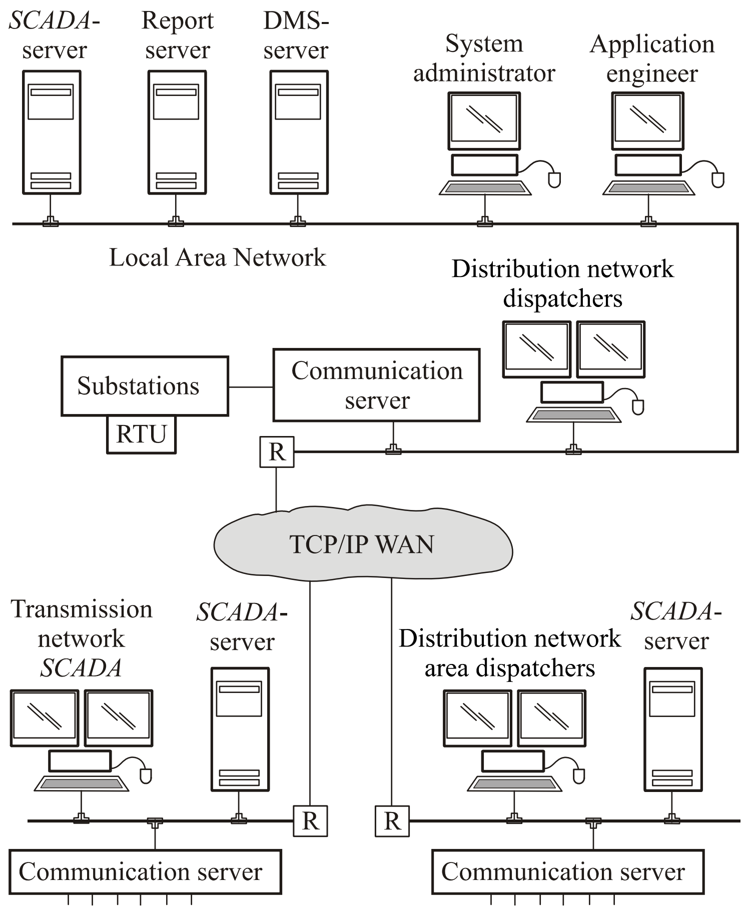

Figure 3.11. Principal structure of dispatching system

Data is collected at the substation local area systems from where it is transmitted by using local communication lines to the communication servers and furthermore to the *SCADA*-server. In the opposite direction control orders of switches and other devises are transmitted. Long time storing of processed data is performed at report servers. With the help of a wide area network (*WAN*) different regional and also transmission network control centres are connected to the distribution network control centre. Local area (*LAN*) and wide area networks are connected through router *R*. Information on electrical networks communication systems is available in [141].

Local area systems are formed by substation automation systems, based on which the data acquisition is carried out and control settings and orders are transmitted. In the local systems the signals received from transducers are transformed to suitable form, they are processed and saved. Required information is transmitted to higher level with appropriate size and at the necessary moment. The devise that prepares the information is called remote terminal unit (*RTU*).

For data transfer communication systems are needed. The problem here is that the area of distribution network could be quite large and the amount of data may be large. Sufficient data transfer rate and high reliability can be obtained by using fibre-optical cables. Furthermore, problem with the communication between the devices from different manufacturers is an important issue. Recently the standardization of data communication protocols has been initiated to resolve the described problem. Data communication between substations and control centres can be realized through *TCP/IP* network or using direct channels in case of more secure data transfer, e.g. relay protection communication.

The central systems are the highest level of a dispatching system. They consist of different servers and communication interfaces to collect, analyse and prepare information for distribution network operational control and analysis.

4 ELECTRICAL NETWORK LOAD

4.1 Principles of load monitoring

Power system operation is determined by the behaviour of the load. The purpose of generation, transmission and distribution system is to cover the load in all conditions. The balance between generation and consumption must exist at all times. It is not possible to consume electricity when no production is available and on the other hand it is not possible to produce electrical energy when there is no consumption. If some unbalances occur it may lead to endangerment of power system security. Therefore, to uphold the system, appropriate countermeasures, considering economical and reliability criterions i.e. generation adequacy and system balancing with available reserves at all times, should be applied. Hence, deeper understanding of load and its effect on the power system operation in shorter and in longer periods is essential.

In power system analysis load values are basically needed for three main purposes: for system stability studies, for short- and long-term planning of system operational dynamics and for short- and long-term system planning. Each of those applications needs different approach. For example, in long-term system planning, economical development situation, forecasts and other socio-economic criteria are considered. In power system stability studies the load is modelled considering the imminent effect of system behaviour to contingencies. In this thesis, the attention is paid to the modelling and handling of the load from the perspective of modelling and analysis of the distribution network operational dynamics.

Load changes regularly, depends on consumer practices, weather conditions, and has a stochastic nature. When comparing the nature of loads from different levels, it is noticeable that lower level loads have more stochastical nature than higher level loads. In general, the load is not controllable, but to some extent it is possible, i.e. through electrical tariffs or using the load dependency of operational parameters (voltage and frequency). Using the controllability options, e.g. demand side management approach, it is possible to shift the load peak values, equalize the load curve etc. and as a consequence relieve system loading and influence system operation.

Load can be observed as consumption of a certain consumer, substation, region or system. The influence of different external factors on the load is different and depends on how the load is considered, i.e. substation load is formed by summing up different consumer loads and therefore load parameters, shape of the load curve, dependency on temperature and stochasticity are somewhat different than in the case of individual loads. Adequate understanding of the load enables more optimally divide resources and knowledge between different fields and applications.

In power system monitoring and analysis load has an important role. For example, based on short-term forecast of a load of substation or a region, it is possible to determine the transmission limits or the need for balance power in the network. It is possible to assess the possible network operation and determine the possible solutions for system enhancement in critical contingencies. In a longer perspective it is important to forecast the load as accurately as practicable to avoid possible system security problems due to the lack of investments in previous years. Using the value of load it is possible to simulate different system operation cases and scenarios to assess and discover the most optimal solution considering different contingencies.

Furthermore, in order to perform network calculations, to design and analyse the network, precise modelling of load in different conditions is substantial. Different scenarios to be investigated require adequate input characteristics, also load values in different conditions among them. Errors in operational and different system planning stages could reflect an increase in expenses directly or a decrease of system reliability in longer perspective. For example, if system operator forecasts its next day load inaccurately, it has to buy additional reserve power next day and consequently lose money i.e. balancing power is always more expensive than the power that is bought in advance.

Necessary load characteristics in different conditions like low or high outdoor temperature, probable deviations of load, different load alteration scenarios, etc. are needed. Practically necessary type of load data depends on the application. Almost in every case the mathematical expectation is needed as a long-term forecast or for some other purposes. Depending of the task, the mathematical expectation corresponds to power or current at a certain time moment, or the mean value of time period (hour, day, week or year). When modelling the load the influence of temperature should be considered. It is mostly considered in a short-term forecast, but in case of long-term forecast and load analyses, the temperature dependency may be simulated. Stochasticity of load is also an important component that should be observed. The stochasticity of load is taken into account through load standard deviation and distribution function. In addition, other load characteristics for describing the load from different viewpoints may be used.

The observation and treatment of loads depends on applications. Generally, the load values are needed for solving operational problems as initial data. The most common output are the values obtained at different given conditions for short- and long-term load forecast, as well as load analysis and simulation results. Hence, the main purposes of load treatment are:

- short-term forecasting of total load
- analyses and simulation of total load
- short-term forecasting of electrical network busloads
- analysis and simulation of electrical network busloads
- treatment of electricity consumer load.

The most common and useable task considering the load is short-term forecast of the total load of some region or the whole electrical power system. The field of implementation is, for example, power system operational planning, including optimal load distribution between generating units or operation in electricity market conditions. Both of those tasks have an enormous effect on overall system operation.

Planning in longer perspective is an importance of the same level as short-term planning or even higher. In longer time scale special attention should be paid to the modelling of load at different conditions e.g. weather, load increase scenarios, etc. Based on the results, it is possible to derive optimal decisions in longer time frame to secure reliable electrical network operation, i.e. the use of accurate information enables to plan necessary fuel resources and establish electricity-trading contracts more precisely. In the case of long-term forecasts the consideration of regional economic development plans and expected technical changes in the network would be beneficial.

Monitoring and calculation of the electrical network operation is largely based on busloads. In a shorter time period (a few days ahead) the monitoring and calculation of electrical network operation expresses a need to optimize network operation, to ensure sufficient reliability and power quality. Adequate understanding of network operation in shorter or longer time period is essential for optimal operation and planning of electrical network. Therefore, the need to understand the load and its behaviour is inevitable.

In case of long-term planning of electrical network, different network busload values should be simulated at various conditions e.g. low or high outdoor temperature, possible load deviations, place and time of connecting new electricity consumers, load increase scenarios etc. Load cases and scenarios, which are caused by commutation on lower level network, switching of reactive power compensators, electricity consumers' development alternatives, and other circumstances, are of considerable importance in treatment and simulation of electrical network and its operation.

Treatment of electricity consumers' load enables to determine the behaviour of certain connection point consumption. It is especially important in the case of electricity market when all consumers must be responsible for their balance. Therefore, modelling of load offers an opportunity to forecast the load and, based on the results, make a contract for the delivery of electricity.

4.2 Alternatives for modelling of load

Over the decades, power system engineers have looked into the world of forecasting of the electrical system load. Different methods based on regression analysis, time-series models, neural networks, fuzzy logic, expert systems etc. have been developed and applied. Comprehensive overview of different load forecasting methods is presented in [7]. In such methods, the needed load forecast is found using formal approach based directly on load data, which is given as time series. Load forecast models are chosen according to the nature of initial data (amount of data) and on the required result (e.g. forecast lead time). In case of forecast models the main attention is paid to the application of formal mathematical methods according to certain circumstances, not to consider the nature of the load.

Although forecast models may give practical results in certain conditions, forecasts and other load characteristics may be found much more accurately and diversely by composing a *mathematical model of load* [142], whereby load is considered as an independent object. By developing the model, the physical nature of the load is examined and described quantitatively. In substantial modelling of load the structure of the model does not depend on the amount of data available or on the possible applications. The load is modelled, not the data. The nature of load does not depend on how it is measured.

The most substantial advantages of the load model are especially clear when possible applications of both types of models are considered. Compared to the forecast models, which are only meant for short-term load forecasting, the load model offers considerably more comprehensive solutions. Besides forecasting, it is possible to analyse and simulate load. The model describes load to the full extent. It considers seasonal changes of load level and load curve shape, trend, temperature, stochasticity etc. that can be considered in case of short- or long-term forecast but also in simulation of load. During long-term forecast, economical and technical conditions of load forming may be considered. It is possible to simulate load by varying, for example, weather conditions and load trend scenarios.

Therefore, the load and forecasting models have little in common. Preferably, the load model could be compared to pattern curves of load, which are used in some applications. However, the application of load models requires additional contribution, compared to forecasting models and other traditional load treatment methods. It is necessary to observe the changes of load character and estimate the model parameters. First of all, it is essential to understand what the load models offer. Hence, to obtain the full benefit, the load model must be constantly handled and developed on engineering level. On the other hand, benefits achieved from load model applications may be significant.

The main principles of load model are as follows [143]:

- The structure of the model does not depend on the amount of data available. The load is modelled, not the data.
- The structure of the model does not depend on the possible applications. It is not important whether the model is used for long- or short-time forecasts or for forecasting at all.
- The complexity of the model is derived from handling of the load. The structure of the model depends on how the load is defined and what is the main purpose to be considered when the load changes.

In the mathematical model of load the following changes of load are considered and modelled:

- *Regular changes* consider periodical load changes in time period, e.g. day, week, year, trend and load behaviour on special days [135], [142], [143], [144].
- *Temperature dependency*, which is especially important when percentage of electrical cooling and heating devices is high and the effect to system operation and modelling is apparent. In the mathematical model the inertia of temperature dependency, non-linearity and time changes are considered. In [V]/[145] the principles of consideration of temperature dependency are presented and the overall influence to network operation is observed.

- *Dependency on state parameters* is expressed through voltage and frequency sensitivity.
- *Stochasticity*, which is especially important in case of smaller distribution network loads. These loads have rather high standard deviation in relation to mathematical expectation. In addition, large deviations, which do not match with normal distribution, may occur. Principles of stochasticity of load and its regularities are presented and analysed in [IV]/[146].
- *Controllability*. In wider perspective, electrical network load can be controlled indirectly through tariffs and directly through system dispatching. From operational dynamics perspective switchings that are performed in lower level networks causing changes in busloads at higher level may also be considered as one possibility of controllability.

In the load modelling process the load is considered as an object, which has name, connection point, characteristic composition of consumers etc. Quantitatively, active and reactive power and current describe load. The data used may be in regular form (time-series) or as some representative value (annual energy etc.). Active and reactive power or current are only load data, i.e. they are different phenomena of load.

The mathematical model of load consists of different components, from which the most important are mathematical expectation, temperature dependency and stochastic component. Mathematical expectation describes regular changes of load in normal conditions. Temperature dependency and stochastic component are considering temperature influence and stochasticity of load, respectively. Weather factors as sun radiation, air humidity, wind speed etc. may be also considered through computational value – effective temperature. The dependency on operational parameters is considered through characteristic curve of frequency and voltage. Frequency dependency is typical to active power (power system balancing) and voltage dependency to reactive power (network busload treatment).

The structure of the mathematical model is the same for all loads. In order to use the load model to characterize the specific load the model parameters must be estimated. In the estimation process all regular data and other available quantitative and qualitative information about the load is used. If the existing data is not enough to evaluate all parameters of the model, then type-models (i.e. a typical set of model parameters) may be used. The result of estimation will be a complete model for all loads independently from the amount of used data. If more data is available then also the result will be more accurate.

For practical implementation of mathematical load model for system analysis different load characteristics e.g. short-term and long-term forecast and simulated load values on different conditions e.g. extreme temperatures etc. are needed. Those practical values of load are not directly contained in the mathematical model, but based on the model, it is possible to obtain and apply the appropriate characteristics for required purposes.

Mathematical model of load is based on considering the regularities of load but though some loads exist, changes of which are so irregular that they are impossible to be accurately described. In those cases, the load mathematical expectation and standard deviation are considered as constant, and the stochastic component will be decisive. It may be considered as trivial model of load. In that case the accuracy of trivial model will remain lower than in the case of the normal model.

The forecast models, irrespective of method used, which are based on short-period data, should always be considered as trivial models, because they do not express load regularities systematically. To express all load features, longer (few years) monitoring of load and its behaviour is required. It is necessary to investigate load regularities and describe them quantitatively. Therefore, used forecast models are the same as trivial models, defined from the load modelling perspective.

However, the load model is not another magic method that automatically solves all problems but rather a tool for specialists, which with appropriate application programs, enables effectively implement the engineering visions.

4.3 Mathematical Model of Load

In a wider perspective the electrical network load is formed by consumption of electricity at different locations connected to the network and by the network losses. To determine load at certain region, substation, transformer, etc. one must combine the lower level loads and use the obtained results for necessary purposes. The load of some region, substation, etc. can be observed and treated as an object that is characterised with:

- general data
- load data
- mathematical model of load.

General data consists of information considering basic information about the load, for example, name, connection point, rated power, the type of load (electricity consumers' composition – home, industry, mixed), etc.

Load data includes the values of active and reactive power, current, bus voltage, outdoor temperature etc., based on which, it is possible to assess the nature of the consumption in a certain region. The obtained load data may be both regular (time-series) or non-regular single data (yearly energy, minimum and maximum values, etc.). The information on load could be received through network *SCADA* or some other information system.

The mathematical model of load describes the nature of load changes considering regular changes, dependency on temperature and stochastic nature of load. Comprehensive overview of mathematical modelling of load and its applications could be found in [135], [141], [142], [143], [147], [159].

4.3.1 General Form of the Load Model

Changes of the load (active power, reactive power, or current) can be described by the mathematical model that consists of three basic components:

$$P(t) = E(t) + \Gamma(t) + \Theta(t) \tag{4.1}$$

where $E(t)$ is the mathematical expectation of the load

$\Gamma(t)$ is the temperature-sensitive part of the load
$\Theta(t)$ is the stochastic component of the load.

The first component, mathematical expectation *E(t)*, describes regular changes of a load, e.g. general trend and seasonal, weekly, and daily periodicity in normal conditions (normal temperature, rated frequency and voltage etc.). Mathematical expectation is principally non-stochastic.

Load deviations, caused by deviations of outdoor temperature from the normal temperature are described by the temperature-sensitive part of the model, $\Gamma(t)$. The normal temperature (mathematical expectation of the temperature) is considered as the average outdoor temperature of the last 30 years on any given hour of the year. Besides other features, temperature dependency of load is characterized by a delay of about 24 hours. If the actual outdoor temperature corresponds to the normal temperature (considering delay), the value of the temperature-sensitive part of the load is zero, $\Gamma(t)=0$.

To compare the temperature dependencies of different loads it is appropriate to normalize the component $\Gamma(t)$ by rate of the temperature dependency of load *R(t)*

$$\Gamma(t)=R(t)\gamma(t) \tag{4.2}$$

where $R(t)$ is the rate of the temperature dependency of load
$\gamma(t)$ is the normalized temperature dependency component.

Here the rate $R(t)$, that represents the load increase when the temperature rises by –1 ºC, determines the level of temperature dependency for every particular load and supports the consideration of its timely changes. Component $\gamma(t)$ describes other regularities of the temperature dependency, e.g. inertia etc. The normalization enables one, for example, to estimate the component $\gamma(t)$ simultaneously for load class, which consists of similar loads.

The third part of the mathematical model, stochastic component $\Theta(t)$, describes stochastic deviations of load. The stochastic measure of load is standard deviation, which is also considered as time variable. Due to the autocorrelation the deviations of load are stochastically dependent on each other. Hence, it is possible to observe the stochastic component of the load by consisting of different components. From practical reasons the stochastic component is normalized. The proper rate is the standard deviation of the load $S(t)$, which expresses the level of stochasticity. The result obtained is

$$\Theta(t)=S(t)\left[\zeta(t)+\xi(t)+\pi(t)\right] \tag{4.3}$$

where $\zeta(t)$ is expected deviation – conditional mathematical expectation of the stochastic component. $\xi(t)$ is normally distributed non-correlated residual deviation (white noise) of the load. $\pi(t)$ is peak component that considers the existence of large positive or negative deviations (peak deviations) that do not correspond to the normal distribution. In practice those deviations may be observed in low- and medium voltage networks, where they cause distortion of load distribution.

Therefore, the mathematical model of a load is

$$P(t) = E(t) + R(t)\gamma(t) + S(t)\left[\zeta(t) + \xi(t) + \pi(t)\right] \tag{4.4}$$

According to this model, $E(t)$ is the mathematical expectation of a load

$$\mathrm{E}\left[P(t)\right] = E(t) \tag{4.5}$$

on the conditions that both stochastic deviations and influence of temperature are missing. *S(t)* is, in its turn, standard deviation of load

$$\sigma\left[P(t)\right] = S(t) \tag{4.6}$$

on the condition that influence of temperature is given and belongs to the mathematical expectation

$$\mathrm{E}\left[P(t)\right] = E(t) + R(t)\gamma(t) \tag{4.7}$$

It should be stated that $E(t)$ and $S(t)$ are first of all components of the model. What real mathematical expectation and standard deviation will be like depends on given conditions.

On the base of the mathematical model it is possible to find load characteristics, which are needed for monitoring of the network operation. When adding both deviation and temperature dependency to the load mathematical expectation it is possible to find the short-term forecast, as load conditional mathematical expectation. The result is

$$\mathrm{E}_\tau\left[P(t)\right] = E(t) + R(t)\gamma_\tau(t) + S(t)\zeta_\tau(t) \tag{4.8}$$

where τ is lead time in the units (an hour or a part of it) of sampling steps (if the lead time is not showed then it is presumed that $\tau = 1$).

When mathematical expectation is found for the future, the result is long-term forecast of the load, corresponding to the normal temperature. In addition, it is possible to calculate various long-time forecasts, according to temperature simulations (cold winter, warm autumn) using the simulated temperature dependency $R(\mathrm{t})\,\gamma(t)$ as follows:

$$P_F(t) = E(t) + R(t)\gamma(t) \tag{4.9}$$

On the base of the mathematical model it is possible to find other required load characteristics.

4.3.2 Components of the Load Model

For development of load model it is rational to observe and describe the load mathematical expectation, standard deviation, and rate of temperature dependency of load as a function of three arguments: yearly (general) time t, daily time h, and type of day l as follows:[1]

[1] Since the yearly time *t*, daily time *h*, and type of day *l* are the functions of general time *t*, we can use different indications to mark the functions, depending on the purpose, e.g. it is possible to use both *P*(*t*) or *P*(*t,h,l*).

$$P(t,h,l) = E(t,h,l) + R(t,h,l)\gamma(t) + S(t,h,l)[\zeta(t) + \xi(t) + \pi(t)] \tag{4.10}$$

Considering timely changes of mathematical expectation, standard deviation, and rate of load, it is possible to present the components of the mathematical load by the following expressions:

$$\begin{aligned} E(t,h,l) &= \mathbf{M}^T(h)\mathbf{G}_{El}\mathbf{N}(t) \\ S(t,h,l) &= \mathbf{M}^T(h)\mathbf{G}_{Sl}\mathbf{N}(t) \\ R(t,h,l) &= \mathbf{M}^T(h)\mathbf{G}_{Rl}\mathbf{N}(t) \end{aligned} \tag{4.11}$$

here $\mathbf{M}(h)$ and $\mathbf{N}(t)$ are vector functions consisting of components that correspond to daily and annual load changes. $\mathbf{G}_{El}$, $\mathbf{G}_{Sl}$, and $\mathbf{G}_{Rl}$ are matrices consisting of parameters depending on day type l. Respectively,

$$\mathbf{M}(h) = \begin{bmatrix} \mu_0(h) \\ \mu_1(h) \\ \cdots \\ \mu_{MDC}(h) \end{bmatrix}, \ \mathbf{N}(t) = \begin{bmatrix} \nu_0(t) \\ \nu_1(t) \\ \cdots \\ \nu_{NAC}(t) \end{bmatrix} \tag{4.12}$$

and

$$\mathbf{G}_{El} = \|g_{Elks}\|, \ \mathbf{G}_{Sl} = \|g_{Slks}\|, \ \mathbf{G}_{Rl} = \|g_{Rlks}\| \tag{4.13}$$

where k = 0...MDC and s = 0...NAC. Here the vector components, corresponding to index 0, are trivial

$$\mu_0(h) \equiv 1, \ \nu_0(t) \equiv 1 \tag{4.14}$$

The number of non-trivial components MDC and NAC is predominantly 4, but different values are also possible.

When continuing the model development it is possible to develop matrices $\mathbf{G_E}(l)$, $\mathbf{G}_S(l)$, and $\mathbf{G}_R(l)$ into series

$$\begin{aligned} \mathbf{G}_{El} &\cong a_{l0}\mathbf{G}_0 + a_{l1}\mathbf{G}_1 + a_{l2}\mathbf{G}_2 + \ldots + a_{l,NSC}\mathbf{G}_{NSC} \\ \mathbf{G}_{Sl} &\cong b_{l0}\mathbf{G}_0 + b_{l1}\mathbf{G}_1 + b_{l2}\mathbf{G}_2 + \ldots + b_{l,NSC}\mathbf{G}_{NSC} \\ \mathbf{G}_{Rl} &\cong c_{l0}\mathbf{G}_0 + c_{l1}\mathbf{G}_1 + c_{l2}\mathbf{G}_2 + \ldots + c_{l,NSC}\mathbf{G}_{NSC} \end{aligned} \tag{4.15}$$

where $\mathbf{G}_0 = \|1\|$. The result obtained is

$$\begin{aligned} E(t,h,l) &= \mathbf{M}^T(h)\sum_r (a_{lr}\mathbf{G}_r)\mathbf{N}(t) \\ S(t,h,l) &= \mathbf{M}^T(h)\sum_r (b_{lr}\mathbf{G}_r)\mathbf{N}(t) \\ R(t,h,l) &= \mathbf{M}^T(h)\sum_r (c_{lr}\mathbf{G}_r)\mathbf{N}(t) \end{aligned} \tag{4.16}$$

where r = 0…NSC. Actually, NSC = 10…12.

Types of day $l = 1\ldots NTP$ correspond first of all to normal weekdays ($l = 1\ldots 7$). Besides regular weekdays the special days (holidays, pre-holidays, post-holidays, etc.), which $l > 7$, are also observed and considered in the model because the nature of the load on those days may differ from that on regular days [144]. The number of above mentioned special days depends on the specific country calendar and may reach up to 10…15% from the total number off all days. For example, the number of holidays in Estonia and Finland is different and therefore the number of special days is also different. The number of special days also depends on the needed accuracy of modelling. Altogether, the total number of type of days *NTP* may be up to 50…60. In a simplified approach, where the required level of accuracy is not high the special day is considered as a similar weekday (for example, holiday – Sunday, pre-holiday – Friday etc) and the number of types of days is then 7.

It is possible to normalize model parameters a_{lr} , b_{lr} , and c_{lr}

$$a = \frac{1}{7}\sum_{l,r} a_{lr} g_{r00} \text{ , } b = \frac{1}{7}\sum_{l,r} b_{lr} g_{r00} \text{ , } c = \frac{1}{7}\sum_{l,r} c_{lr} g_{r00} \tag{4.17}$$

where g_{r00} is the element of matrix $\mathbf{G}_r$ with index 00. Here the summation is done in the range of ordinary weekdays $l = 1\ldots 7$ (special days are not considered). In the model, particular elements of matrices are replaced as follows:

$$a_{lr} \Rightarrow a \cdot a_{lr} \text{ , } b_{lr} \Rightarrow b \cdot b_{lr} \text{ , } c_{lr} \Rightarrow c \cdot c_{lr} \tag{4.18}$$

The normalization of parameters cannot be done if the calculated mean value is too small (zero) or negative. That situation may occur in the case of reactive power and current. In the described case

$$a = b = c = 1. \tag{4.19}$$

Hereafter the parameters a, b, c and a_{lr}, b_{lr}, c_{lr} are observed as level factors and shape factors, respectively.

Level of load may change over the observable period. Long-term load increase or decrease is presented as an additional component of the model – trend. Trend component is presented as quadratic function

$$A(t) = a\left[1 + \alpha_1 (t - t_0) + \alpha_2 (t - t_0)^2\right] \tag{4.20}$$

where α_1 and α_2 are factors and t_0 is the time moment from where the computation of trend starts. Trend may also be presented with a linear fractional function, i.e. every year has its own trend and different factors (Fig. 4.1).

Beside mathematical expectation, trend also belongs to the standard deviation and to the rate of the temperature dependency, respectively, as

$$B(t) = b\left[1 + \alpha_1 (t - t_0) + \alpha_2 (t - t_0)^2\right] \tag{4.21}$$

$$C(t) = c\left[1 + \alpha_1 (t - t_0) + \alpha_2 (t - t_0)^2\right] \tag{4.22}$$

Voltage and frequency sensitivity of the load is described as quadratic functions

$$U(u) = 1 + \mu_1 u + \mu_2 u^2 \tag{4.23}$$

and

$$F(f) = 1 + \nu_1 f + \nu_2 f^2 \tag{4.24}$$

where $u = U_V / U_N - 1$ and $f = F_V / F_N - 1$.

Here $\mu_1, \mu_2, \nu_1, \nu_2$ are factors and U_V, U_N and F_V, F_N are observed as rated values of voltage and frequency, respectively.

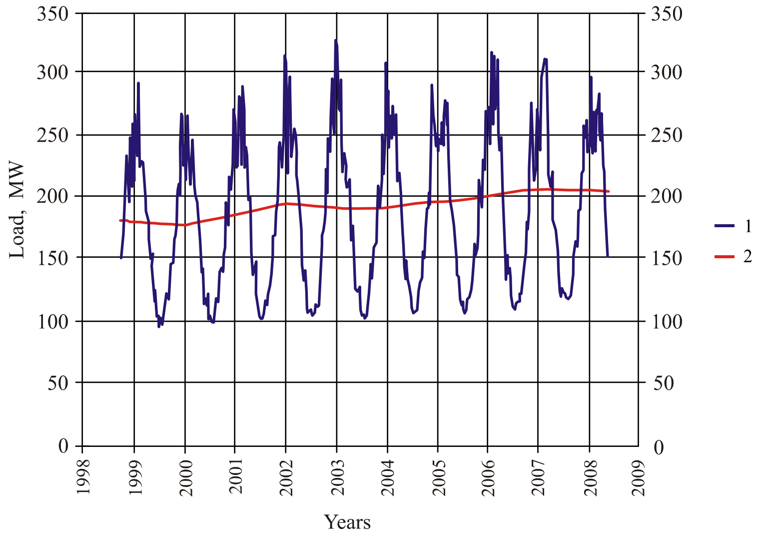

Figure 4.1. Actual value (1) and trend (2) of load

Voltage and frequency sensitivity are considered only in connection with mathematical expectation. Consequently

$$\begin{aligned} E(t,h,l) &= A(t)U(u)F(f)\mathbf{M}^T(h)\sum_r (a_{lr}\mathbf{G}_r)\mathbf{N}(t) \\ S(t,h,l) &= B(t)\mathbf{M}^T(h)\sum_r (b_{lr}\mathbf{G}_r)\mathbf{N}(t) \\ R(t,h,l) &= C(t)\mathbf{M}^T(h)\sum_r (c_{lr}\mathbf{G}_r)\mathbf{N}(t) \end{aligned} \tag{4.25}$$

Components $\mu_i(h)$ (i = 1…*MDC*) of vector function $M(h)$ are presented by points (in table form). The number of those points depends on the density of sampling data, e.g. once an hour or more frequently. The components, corresponding to annual changes $\nu_j(t)$ (j = 1…*NAC*), are approximated with the Fourier' series

$$\nu_j(t) = \sum_{k=1}^{MB} \left[a'_{jk} \sin\left(\frac{2\pi}{T}kt\right) + a''_{jk} \cos\left(\frac{2\pi}{T}kt\right) \right] \tag{4.26}$$

The order of the considered series MB is usually 4 or 5. Hence, the number of parameters for one component of vector function $\mathbf{N}(t)$ is 8 or 10. The examples of the components of the vector functions $\mathbf{M}(h)$ and $\mathbf{N}(t)$, which are also called co-ordinate functions of the model, are shown at Fig. 4.2 and Fig. 4.3.

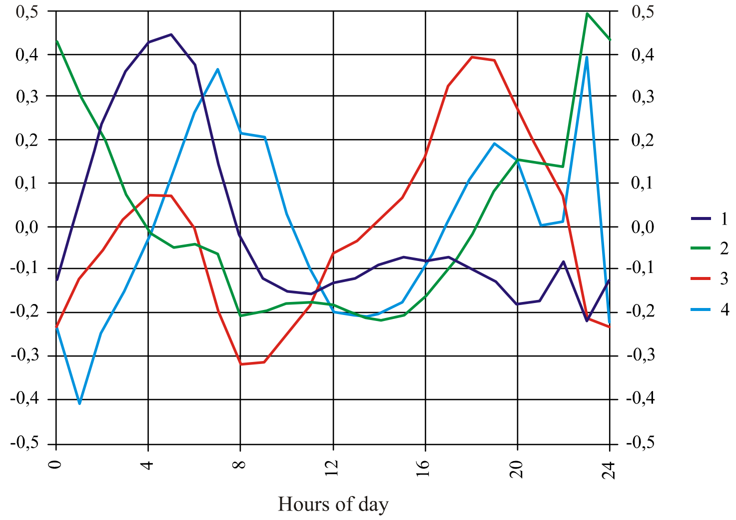

Figure 4.2. Components of vector function $\mathbf{M}(h)$

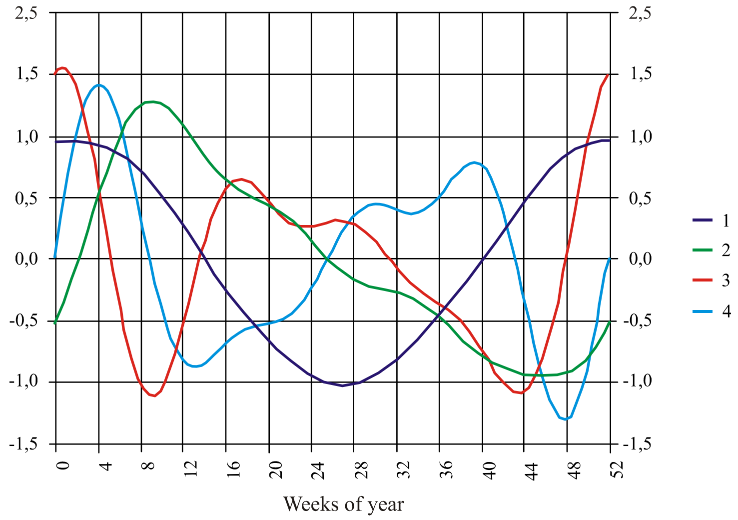

Figure 4.3. Components of vector function $\mathbf{N}(t)$

Examples of load modelling are presented in Fig. 4.4 and Fig. 4.5, where load actual values and mathematical expectation of load on weekly and hourly level are showed.

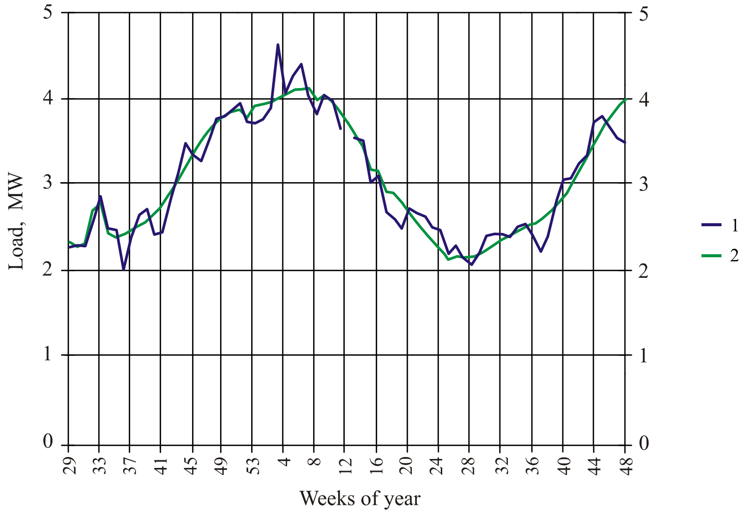

Figure 4.4. Actual value (1) and mathematical expectation (2) of load, weekly values

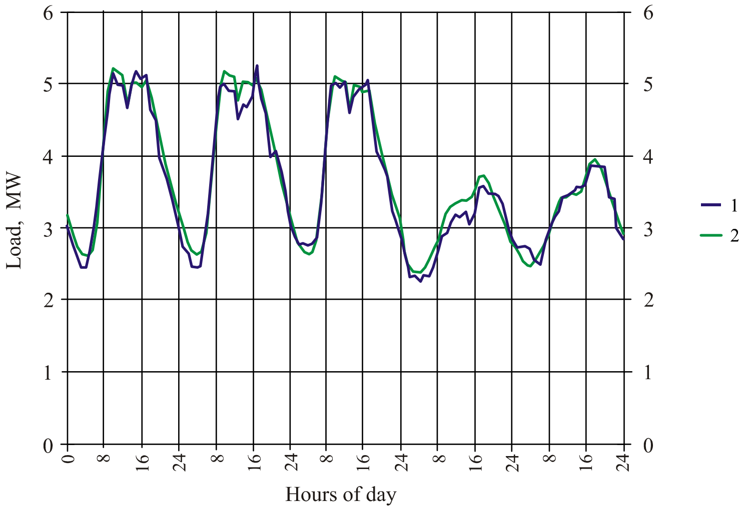

Figure 4.5. Actual value (1) and mathematical expectation (2) of load, hourly values

Regular changes of temperature must also be considered and modelled. Structure of the temperature model is principally the same as for the load model, but some simplifications are made. Those simplifications are due to the reason that there is no need to distinguish different day types in case of temperature. Hence, there is no need for developing parameter matrices into series. Concisely, the temperature model consists of only one type of $\mathbf{G}_E$ and $\mathbf{G}_S$ matrices, which, together with co-ordinate functions, determine the mathematical expectation $E_T(t,h)$ (normal temperature) and standard deviation $S_T(t,h)$ of temperature $T(t,h)$

$$E_T(t,h) = \mathrm{E}\big[T(t,h)\big] = \mathbf{M}_T^T(h)\mathbf{G}_{TE}\mathbf{N}_T(t) \tag{4.27}$$

$$S_T(t,h) = \sigma\left[T(t,h)\right] = \mathbf{M}_T^T(h)\mathbf{G}_{TS}\mathbf{N}_T(t) \tag{4.28}$$

Principally it is possible to estimate the model parameters for each load individually, but in some cases it is not reasonable. For example, in a distribution network, where the number of loads is significantly larger than in a transmission network, it is rational to estimate some of the model components common for several loads. It is supported by the structure of the model, which enables us to classify the model parameters according to the following hierarchy:

- group of load – vector functions $\mathbf{M}(h)$ and $\mathbf{N}(t)$ – co-ordinate functions
- class of load – matrices $\mathbf{G}_r$ – shape co-ordinates
- type of load – parameters a_{lr}, b_{lr} and c_{lr} – shape factors
- individual load – parameters a, b, c and other factors of the trend – level factors.

Hereafter the co-ordinate functions and shape co-ordinates as well as sub models describing temperature dependency and stochasticity of load are referred to as model components, shape and level factors as model factors. Described terminology is in accordance with formation and implementation of the type models. Generally, network loads are classified and model co-ordinate functions, shape co-ordinates, and factors are estimated according to respective load groups, load classes, and load types. The minimum requirement for the initial data is only one value (e.g., yearly energy). If the amount of reliable data is large enough, all factors and even co-ordinate functions (i.e., all model parameters) may be estimated for each load individually.

4.3.3 Temperature Dependency of Load

Dependency on outdoor temperature is one of the most important properties of load. First of all, the load temperature dependency expresses there, where the electrical heating or air conditioning devices are used. For example, in Lapland (Finland), where electrical heating is of great importance and outdoor temperature changes are large, the load increase caused by the outdoor temperature may be up to 100% compared to the load at normal temperature. Usually, however, the temperature dependency of load is smaller, especially in the case of industrial load. The influence of temperature to load and its main characteristics is observed in [V]/[145].

Besides outdoor temperature, electrical network load depends on other meteorological factors e.g. sun radiation (cloudiness), wind speed, humidity etc. To avoid unreasonable complexity of the model and possible estimation difficulties, only the basic factor, outdoor temperature, is considered. It must be emphasised that only factors, which are treated (including forecasted) by meteorological services in a quantitative way will be considered. Principally other weather factors can be considered through transformed value of temperature, i.e. through effective temperature. Of course, this value must also be treated by meteorological services.

The mathematical model of the temperature dependency describes the increase of load when the outdoor temperature changes. In addition to the level of load deviations due to the temperature, the delay of the temperature influence (inertia), changes in time and non-linearity must be considered. As known, the delay of about 24 hours is characteristic to the temperature influence. Yearly changes must be taken into account, since the temperature dependency in summer differs remarkably from temperature dependency in winter. The variability of weekly and daily temperature dependency must also be considered. A non-linearity phenomenon occurs when, in certain temperature values, the character of temperature dependency change. For example, in summer time, when the temperature dependency in the northern lands is mostly missing, load increase can be recognised if temperature falls below 14 °C or rises above 25 °C. In wintertime, the speed of load increase may decrease if the temperature falls below -25 °C etc. These phenomena can be explained by using additional heating or cooling equipment in summertime and achieving the maximum output of heating equipment or finishing outdoor works in wintertime.

The temperature dependency component is depicted as

$$\Gamma(t) = R(t,h,l)\gamma(t) \tag{4.29}$$

The rate *R(t,h,l)*, or in substance the temperature sensitivity of load, determines the level of the temperature dependency for every single load and supports the consideration of timely changes. It represents the load increase when the temperature rises by 1 ºC. Temperature sensitivity has a variable nature in seasonal, daily and hourly level. As an example, the changes of the temperature sensitivity on weekly and hourly levels are presented in Fig. 4.6a and Fig. 4.6b, respectively. The temperature sensitivity, the unit of which is MW/ºC is, in this case, negative – the rise of the temperature causes a fall of load and vice versa. The highest effect of the temperature is in winter. The peak in daily temperature sensitivity at 23.00 is apparently caused by switching of the heating devices, due to the change in tariffs at that time.

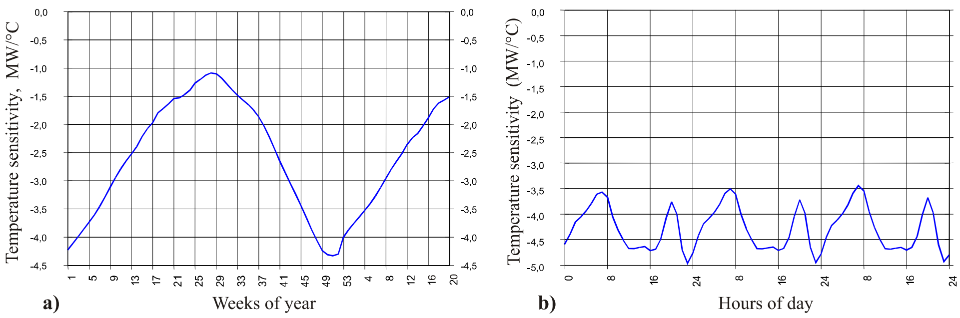

Figure 4.6. Temperature sensitivity of the load, weekly (a) and hourly values (b)

Rate of temperature dependency *R(t,h,l)*, enables to estimate the relative temperature dependency component $\gamma(t)$ according to the load class, simultaneously for many loads to be comparable for different loads. The component $\gamma(t)$ represents the temperature deviation, unit °C. In the first approximation, the temperature effect on the load may be found by deviation of temperature

$$\Gamma(t) = R(t,h,l)\Delta T(t) \tag{4.30}$$

where $\Delta T(t) = T(t) - \mathrm{E}[T(t)]$ is the temperature deviation from normal temperature and consequently relative temperature dependency component $\gamma(t) = \Delta T(t)$. In practice, more precise presentation of the component $\gamma(t)$ is necessary. It should enable more detailed description of the temperature dependency of the load, first of all, considering the delay of the temperature influence (inertia).

To present the normalized temperature dependency component it is appropriate to apply the time series *ARIMA*-model (*Integrated Autoregressive Moving Average Model*), which is also called as *Box-Jenkins* model [148] as follows

$$\gamma_t = \frac{\Psi_T(B)}{\Phi_T(B)}\Delta T_t \tag{4.31}$$

where $\Phi_T(B)$, $\Psi_T(B)$ are polynomials of the shift operator B $(Bx_t = x_{t-1})$. If operators $\Phi_T(B)$ and $\Psi_T(B)$ are presented in the form of

$$\Phi_T(B) = 1 - \varphi B\,,\ \Psi_T(B) = \psi B^m \tag{4.32}$$

where φ, ψ, and m are parameters, then the component $\gamma(t)$ corresponds to transfer function, shown in Fig. 4.7 with parameters

$$H_0 = m,\ H = \frac{\varphi}{1-\varphi},\ \gamma_\infty = \frac{\psi}{1-\varphi} \tag{4.33}$$

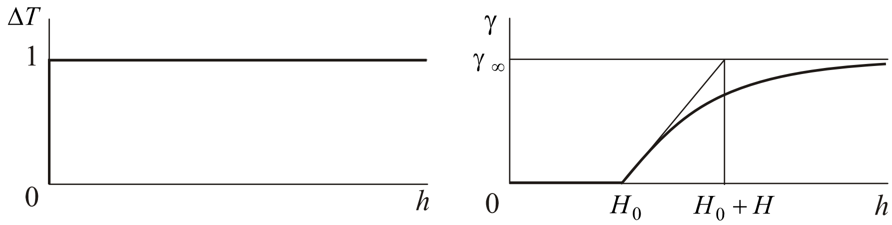

Figure 4.7. Transfer function of temperature dependency

According to this transfer function, the influence of the temperature change on the load starts after H_0 hours, H is time constant of temperature dependency. For example, if $H_0 = 5$ and $H = 10$, then temperature change will affect the load fully after about $H_0 + 2H = 25$ hours (i.e. on the next day).

In addition to level and inertia, one must also consider changes of temperature dependency in time and non-linearity. Changes in time are first of all considered through rate of temperature dependency *R*(*t*). In addition, changes of relative temperature and $\gamma(t)$ should also be considered. Change of $\gamma(t)$ is taken into account by considering the change of the model parameters in time. It is essential to consider seasonal variability, because influence of temperature differs significantly from that of winter. If necessary, changes of weekly and daily temperature dependency may also be taken into account. A non-linearity phenomenon occurs when, in certain temperature values, the characteristics of temperature dependency changes. These phenomena are in conjunction with temperature deviation from certain value instead of mathematical expectation of temperature. In the model, non-linearity is considered by adding the so-called marginal components, which will be activated if temperature falls below or reaches above the threshold values T_1 or T_2. Considering the previous, the temperature dependency component $\gamma(t)$ should now be observed as consisting of three parts

$$\gamma_t = \gamma_{0t} + \gamma_{1t} + \gamma_{2t} \tag{4.34}$$

where

$$\Phi_{T0}(B)\gamma_{0t} = \Psi_{T0}(B)(T_t - T_{0t}) \tag{4.35}$$

$$\Phi_{T1}(B)\gamma_{1t} = \begin{cases} \Psi_{T1}(B)(T_t - T_1), & \text{if } T_t < T_1 \\ 0, & \text{if } T_t \geq T_1 \end{cases} \tag{4.36}$$

$$\Phi_{T2}(B)\gamma_{2t} = \begin{cases} \Psi_{T2}(B)(T_t - T_2), & \text{if } T_t > T_2 \\ 0, & \text{if } T_t \leq T_2 \end{cases} \tag{4.37}$$

here $T_{0t} = \mathrm{E}[T_t]$ is mathematical expectation of the temperature.

If the delay in the case of marginal components has the same level as the main components, then the temperature dependency model is

$$\gamma_t = \varphi B \gamma_t + \psi_0 B^m (T_t - T_{0t}) + \psi_{T1} B^m (T_t - T_1)\Big|_{T_t < T_1} + \psi_{T2} B^m (T_t - T_2)\Big|_{T_t > T_2} \tag{4.38}$$

In order to make the model correspond to a certain load, the model parameters must be estimated with that load data. Despite the modest number of parameters some difficulties may arise when using the formal estimation methods (e.g. least-square method). For example, in a summer period, when the temperature influence is small, bad determination between the delay of the temperature influence and the level of the temperature deviation causes problems. Furthermore, it is a problem to estimate the parameters that are associated with non-linearity. The fundamental problem in the observable period is the unilaterality of the weather type. Thus, for example, many years with warm winter, cold summer etc. may occur. The minimal period for the change of the weather types from the meteorological point of view is 30 years. In the above mentioned range the load data is either missing or is not reliable enough due to the changes of the load character. Therefore, it is necessary to estimate the model parameters in two phases. In the first phase, during load research, the larger amounts of loads are handled. As a result, the temperature dependency models are identified – the type cases are found and some of the model parameters are fixed. In the second, model estimation phase, the rest of the parameters are estimated, based on the observable data of single loads.

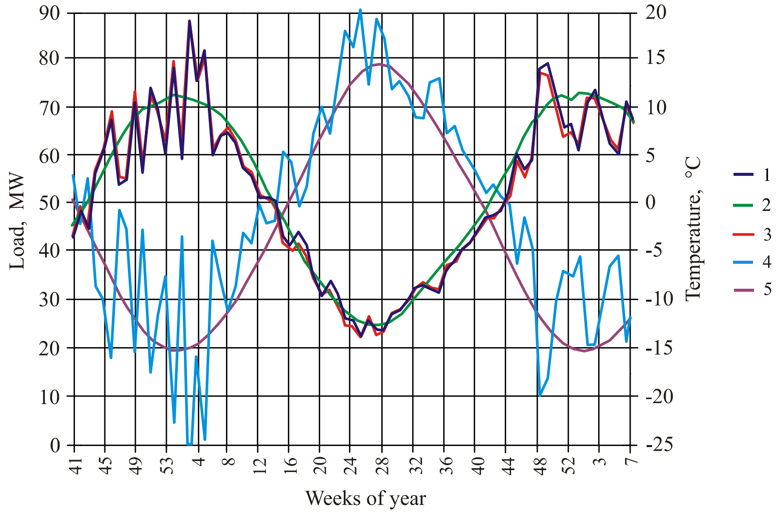

Figure 4.8. Actual value (1), mathematical expectation (2), and expected value (3) of load, and actual value (4), and expected value (5) of temperature, weekly values

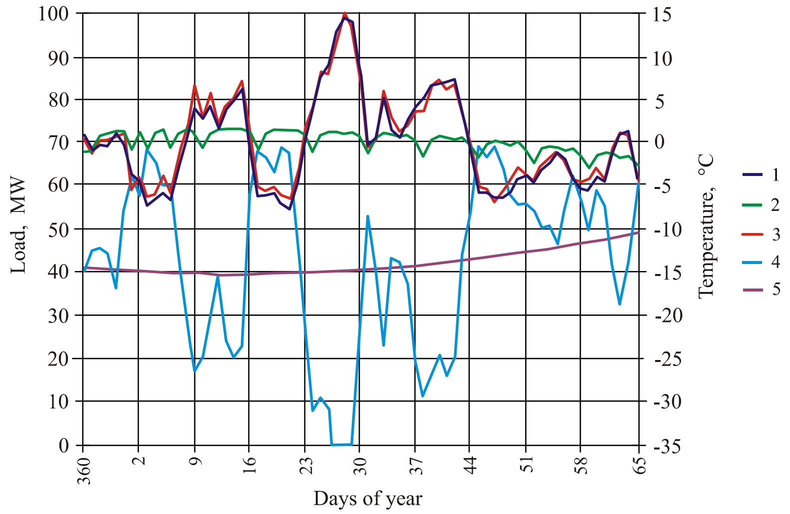

Figure 4.9. Actual value (1), mathematical expectation (2), and expected value (3) of load, and actual value (4), and expected value (5) of temperature, daily values

An example of temperature dependency of load with weekly and daily values at one distribution substations are presented in Fig. 4.8 and Fig. 4.9, respectively. In addition to actual values of temperature and load the mathematical expectations of load and expected value of load and temperature are presented. Here, the expected load has the value which is obtained by adding temperature dependency to the mathematical expectation.

Depending on the needed accuracy of modelling, other load temperature dependency details may be considered. For example, load may not decrease in an ordinary way after a long cold winter period (a week or more) when temperature returns to the normal level. A problem is how to represent the load temperature dependency of accumulative electrical heating. In that case temperature dependency is connected not so much to the power of the heating system but to the duration of the turn-on time.

4.3.4 Stochastic Component of Load

Possible load deviations caused by stochasticity must be considered in designing the electrical network and also in the operation planning. It is necessary to know the standard deviation, characterizing the level of the load stochasticity but also the distribution enabling to estimate the probability of the deviations. The stochastical dependency between random deviations, autocorrelation, is also of interest, because it is the base for the short time forecast. The randomness is especially noticeable in smaller distribution network loads. The principles of stochasticity of load are observed in [IV]/[146].

In the mathematical model the randomness of the load is considered by a stochastic component

$$\Theta(t) = S(t,h.l)\left[\zeta(t) + \xi(t) + \pi(t)\right] \tag{4.39}$$

The level of the stochasticity is expressed by the standard deviation $S(t,h,l)$, which changes in time. $\zeta(t)$ is expected deviation that describes conditional mathematical expectation, $\xi(t)$ is normally distributed non-correlated residual deviation (white noise) of the load and $\pi(t)$ is peak component that considers the existence of large positive or negative deviations (peak deviations) that do not correspond to the normal distribution. As an example, the standard deviation of the load weekly and hourly values are presented in Fig. 4.10a and Fig. 4.10b.

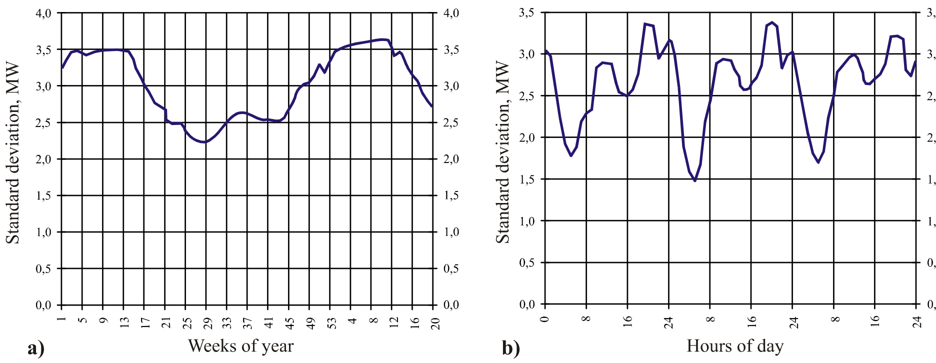

Figure 4.10. Standard deviation of load, weekly (a) and hourly values (b)

From these examples it is noticeable that the changes of the standard deviation resemble the load (mathematical expectation) changes, being larger in winter and in the evenings and smaller in summer and at night. Nevertheless, the closer observation indicates that the changing regularities of the standard deviation may not coincide with the changes of the mathematical expectation.

Random deviation of load

$$\vartheta(t) = \frac{1}{S(t)}\left[P(t) - E(t) - \Gamma(t)\right] \tag{4.40}$$

can be described with the *ARIMA*-model as

$$\vartheta_t = \frac{\Psi(B)}{\Phi(B)}\xi_t \tag{4.41}$$

where ϑ_t is the value of the random deviation in the time interval t, $\Phi(B)$, and $\Psi(B)$ are linear operators, and ξ_t is the value of non-correlated time series - residual deviation of the load (white noise).

Actually, the operators $\Phi(B)$ and $\Psi(B)$ are presented as

$$\Phi(B) = (1 - \varphi_1 B - ... - \varphi_{MF} B^{MF})(1 - \varphi_M B^M)(1 - \varphi_N B^N) \tag{4.42}$$

$$\Psi(B) = (1 - \psi_1 B - ... - \psi_{MP} B^{MP})(1 - \psi_M B^M)(1 - \psi_N B^N) \tag{4.43}$$

Here, the first part of the operators considers the after-effect of load deviations (inside the day), which precede the present time interval. The second and third parts of the operators consider the after-effect of one day backward and one week backward. The daily displacement factors *MF* and *MP* are actually within limits 1…2, and if the sampling frequency is once an hour, then $M = 24$ and $N = 168$. Hence, the model of the stochastic component consists of eight parameters φ_1, φ_2, φ_{24}, φ_{168}, ψ_1, ψ_2, ψ_{24} and ψ_{168}.

Large deviations of the load should be excluded, as they do not belong to the residual deviation ξ_t. The following criterion is suitable

$$|\xi_t| < c_S \sigma_\xi \tag{4.44}$$

where c_s is reliability factor (e.g., 2.7) and σ_ξ is standard deviation of residual deviation. Possible large deviations belong to the peak component π_t of the load.

In practical approach, the load stochastic component is treated recursively. For each time interval (an hour or part of it), value of the deviation ζ_t is found by the Box-Jenkins model. If the difference $\vartheta_t - \zeta_t$ is suitable according to the previous criterion, then $\vartheta_t - \zeta_t = \xi_t$ and peak component value $\pi_t = 0$. If not, then the peak component value differs from zero and $\vartheta_t - \zeta_t = \xi_t + \pi_t$. For separation of components ξ_t and π_t the residual deviation ξ_t is simulated, based on normal distribution $\xi_t' = N(0, \sigma_\xi)$. Hence,

$$\begin{cases} \xi_t = \vartheta_t - \zeta_t, \quad \pi_t = 0, \quad if \ |\vartheta_t - \zeta_t| < c_S \sigma_\xi \\ \xi_t = \xi_t', \quad \pi_t = \vartheta_t - \zeta_t - \xi_t', \quad if \ |\vartheta_t - \zeta_t| >= c_S \sigma_\xi \end{cases} \tag{4.45}$$

The results of handling the stochastic deviation ϑ_t are illustrated in Fig. 4.11. It is observable that the residual deviation of load ξ_t is found for each time period (hour), and the values of peak deviation of load π_t appear from time to time. The expected deviation of the load may be used for short-term forecasting of the load. In Fig. 4.12 an example of actual value of the load and values of mathematical expectation of load $E(t)$ and short-term forecast $E(t)+\Gamma(t)+S(t)\zeta(t)$ are presented.

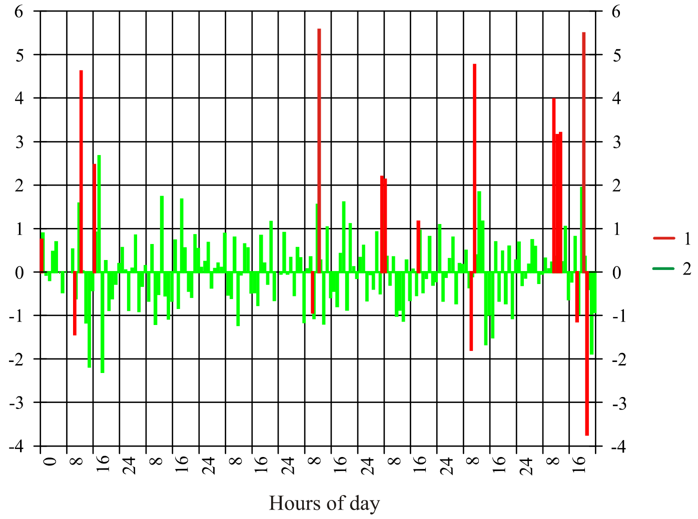

Figure 4.11. Peak deviation (1) and residual deviation (2) of load, hourly values

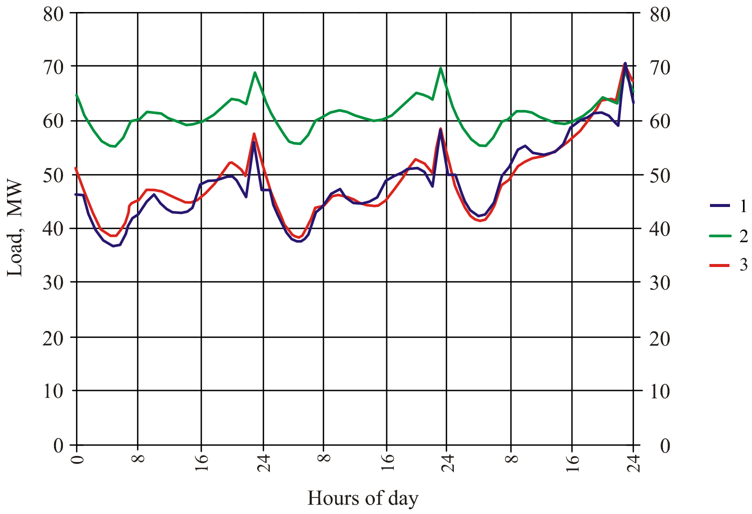

Figure 4.12 Actual load (1), mathematical expectation (2), and short-term forecast (3), hourly values

When analysing and treating the load, normal distribution is often considered, but in general, it is not applicable for electrical network loads. Moreover, the shape of distribution function depends on how the deviation of load ΔP is defined. Attention should be paid to possible load deviation from its mathematical expectation, which is found on the ground of load model as changing in time. If such a model is not used, then an average value of load is considered for a longer time period (e.g., a year) and the deviation is found in relation to that. Furthermore, short-term expected value deviation may be observed in relation to load conditional mathematical expectation, which considers real load progress in the near past and also possible temperature influence. In Fig. 4.13a and Fig. 4.13b deviation histograms, which are found according to load constant average value (first case) and in relation to the mathematical expectation, changing in time (the second case), are presented, respectively. For comparison, normal distribution is also shown on these figures. For assessing maximum load, attention is paid to the “tail” part of the histograms, which are magnified in Fig. 4.14a and Fig. 4.14b. We can see that loads have considerable probabilities of large deviations, which are practically impossible in case of normal distribution. The more recognisable the differences are, the larger the given probability is.

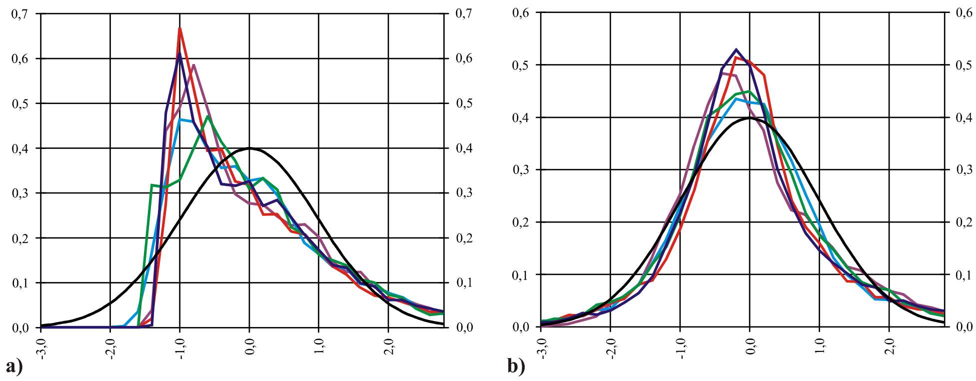

Figure 4.13. Histograms of loads in the first (a) and in the second (b) case

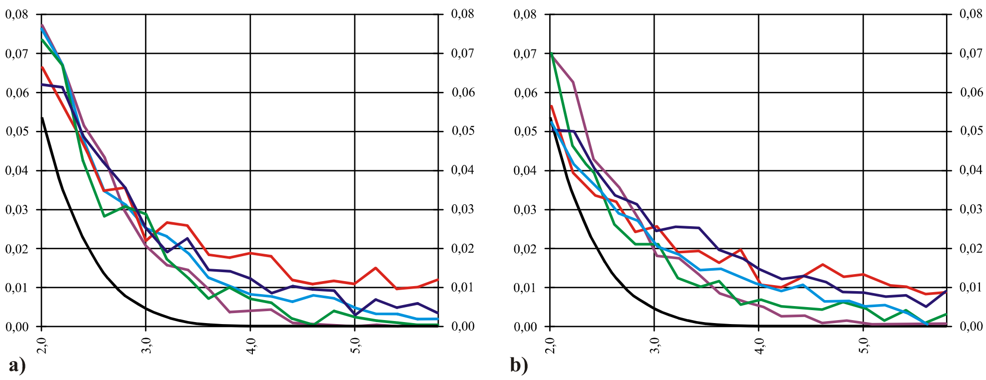

Figure 4.14. Fragment of histograms in the first (a) and in the second (b) case

Residual and peak deviations of load form together the so-called peak normal distribution [146]. Let us assume that a random variable X has peak-normal distribution, when among its normally distributed values large deviations appear from time to time – peaks, which do not conform to normal distribution. The frequencies of positive and negative peaks may be different (including zero). Thus value X with peak-normal distribution consists of normal component X_0 and peak component X_Π. The peak component respectively consists of positive X_1, negative X_2 and zero component Q

$$X = X_0 + X_\Pi \tag{4.46}$$

$$X_\Pi = X_1 + X_2 + Q \tag{4.47}$$

Distribution density of normal component is expressed

$$f_0(x_0) = \frac{1}{\sqrt{2\pi}\sigma_0} e^{-\frac{(x_0-\mu_0)^2}{2\sigma_0^2}} \tag{4.48}$$

If frequencies of positive and negative deviations of the peak component are λ_1 and λ_2, respectively, then, considering that these deviations exclude each other, we get

$$f_\Pi(x_\Pi) = \lambda_1 f_1(x_1) + \lambda_2 f_2(x_2) + \lambda_0 \tag{4.49}$$

where $\lambda_0 = 1 - \lambda_1 - \lambda_2$. Presuming that distribution of deviations is lognormal, we may write

$$f_k(x_k) = \frac{1}{\sqrt{2\pi}\sigma_k |x_k|} e^{-\frac{(\ln|x_k|-\mu_k)^2}{2\sigma_k^2}}, \quad (k = 1, 2) \tag{4.50}$$

where it is considered that the value of X_2 is negative.

Hence, peak-normal distribution is described by 8 parameters: $\mu_0, \sigma_0, \mu_1, \sigma_1, \lambda_1, \mu_2, \sigma_2, \lambda_2$ and it consists of normal distribution, lognormal distribution and Poisson distribution. The last two ones can be substituted also with some other suitable distributions.

Distribution density of value X can be obtained with convolution

$$f(x) = \int_{-\infty}^{\infty} f_0(x_0) f_\Pi(x - x_0) dx_0 \tag{4.51}$$

where f_0 and f_Π correspond to distribution density of the normal and peak component, respectively. The nature of value x_0 depends on how the load deviation ΔP is defined. By considering load deviation in relation to average value $\overline{E}$, mathematical expectation or long- and short-term expected values of the load, deviation may be expressed as follows

$$\Delta P(t) = E(t) + R(t)\gamma(t) + S(t)[\zeta(t) + \xi(t) + \pi(t)] - \overline{E} \tag{4.52}$$

$$\Delta P(t) = R(t)\gamma(t) + S(t)[\zeta(t) + \xi(t) + \pi(t)] \tag{4.53}$$

$$\Delta P(t) = S(t)\left[\zeta(t) + \xi(t) + \pi(t)\right] \tag{4.54}$$

$$\Delta P(t) = S(t)\left[\xi(t) + \pi(t)\right] \tag{4.55}$$

As values $\gamma(t)$, $\zeta(t)$ and $\xi(t)$ are actually with normal distribution, then the equation in square brackets is in all cases normal distribution convolution with peak component. The final form of the load distribution will be achieved with linear conversion, which considers the deterministic functions *E(t)* and *R(t)*

$$f_P(P) = \frac{1}{t_2 - t_1}\int_{t_1}^{t_2} f\left(\frac{P(t) - E(t) - R(t)\gamma(t)}{S(t)}\right)\cdot\frac{1}{S(t)}\,dt \tag{4.56}$$

where (t_1, t_2) is the observed time period. Here the functions *E(t), S(t)* and *R(t)* belong only to the first and second load deviation definitions, in other cases they are missing. Both, distribution function convolution and linear conversion can be realised only numerically.

In Fig. 4.15a and Fig. 4.15b, examples of load distribution curves are shown, whereby the load deviation is found according to load average value (case 1) and in relation to long-term expected value (case 2). For comparison, the normal distribution density curve is also presented.

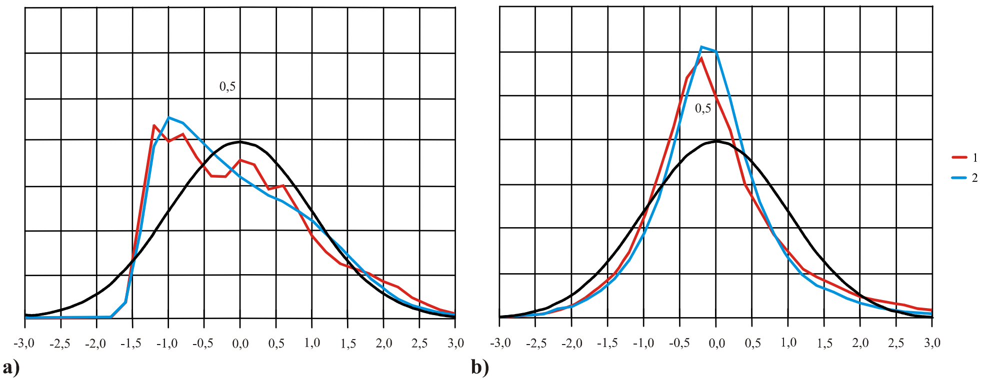

Figure 4.15. Load histogram (1) and peak normal distribution (2) in first case (a) and in second case (b)

In case of summation of the loads, the sum of normally distributed components is also normal and the role of peak component will decrease until it practically disappears. Practically speaking, when considering the electrical network, only transmission grid busloads may be considered as normally distributed. Lower level loads should be considered as having an asymmetric distribution.

4.4 Load Cases and Scenarios

In the monitoring and analysis of distribution network operation occasionally different events induced by load may occur. Especially interesting are the events where the level of load changes and consequently network operation is altered. For example, the busload changes may be caused by the switchings in lower level networks, switchings of reactive power compensation equipment, starting-up or shutdown of large consumers, change of the nature of consumer etc. Those changes in the network busload values may be described as load cases, to which different parameter values of the mathematical model correspond. It must be pointed out that only those changes of network busloads where the level and nature of the change remains different in a relatively longer period of time and which are explainable on engineering bases are considered as load cases. Cases based on network contingencies are not observed. Comprehensive analysis of load cases and scenarios at Estonian power system are presented in [149].

Switchings in lower level networks cause load changes between higher level substations as it is possible to observe in Fig. 4.16. The switchings decrease the load in one substation and increase it in the other.

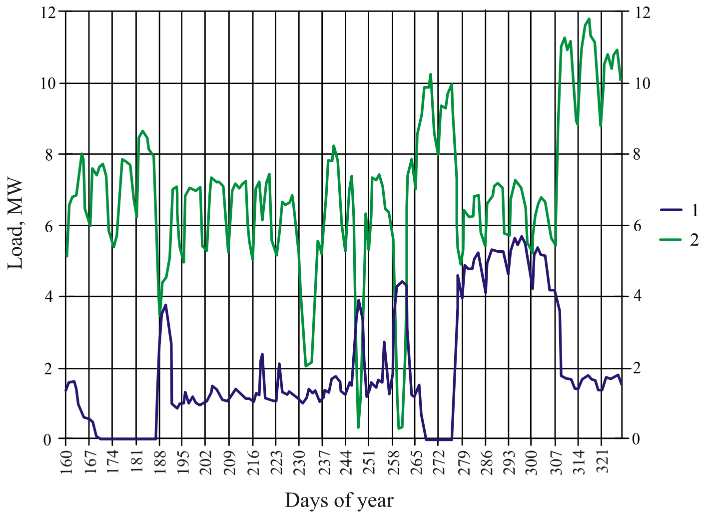

Figure 4.16. Changes of busload values between different substations, daily values

The load cases can be observed in Fig. 4.17a and Fig. 4.17b, where possible levels of load are presented. In the same substation, busload can have two different levels, based on which it is handled.

In addition to active power changes the alteration of reactive power offers also interest in network simulation and analysis. Based on the modelling and analysis it is possible to determine what types of changes occur and what kind of compensation is needed and how and at what times the loads influence each other. In Fig. 4.18 two cases of reactive power change in Estonian substations at weekly and hourly level are presented. Clearly it is possible to observe two different levels and changes of values between them.

Different load cases may be related to each other to form load scenarios. For example, load allocation and changes between different substations, reactive power compensation optimization etc. It should be emphasised that only the most interesting combinations of load changes are observed. From computational aspect, the combination of load cases offers more information and adequate understanding of network operation. Moreover, the information obtained could be used as input for network monitoring purposes. In load scenarios, each load is presented with certain cases because not all load case combinations are feasible or possible to be investigated.

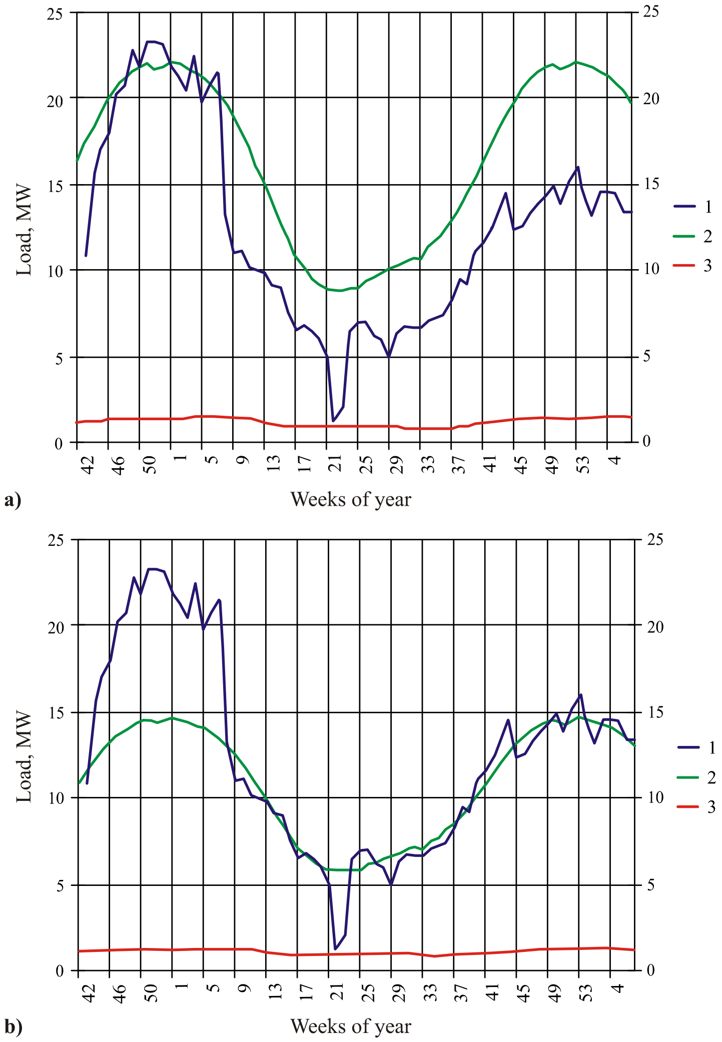

Figure 4.17. Electrical network busload (1), mathematical expectation (2), and standard deviation (3), in the first case (a) and in the second case (b), weekly values

In the mathematical model the modelling of load cases can be incorporated through different sets of model parameters, each of which is valid for certain time intervals. First of all, the level factors change, but when, with the alternating of load cases, the shape of the load curve varies, then the shape factors of the model must also change. Alternation of load cases is realized by means of the program, whereby basic expressions of the model do not need to be changed.

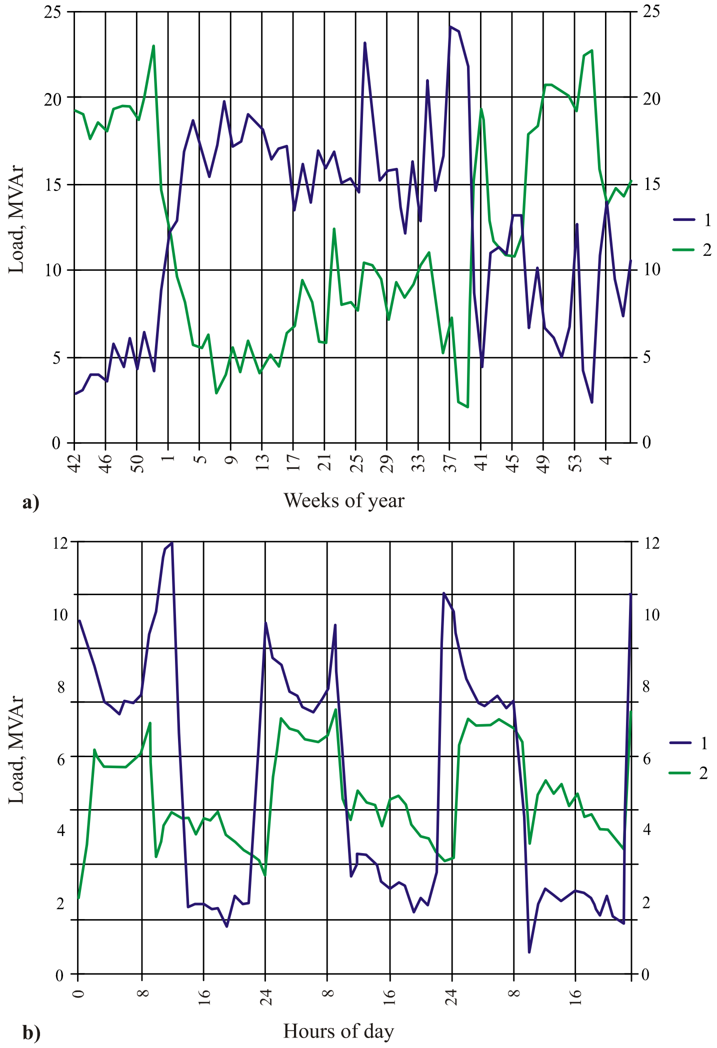

Figure 4.18. Reactive power changes between different substations, weekly (a) and hourly (b) values

4.5 Load characteristics

The above described mathematical model of load describes load, but it does not directly give the values that are required in practical applications (for example, load forecast etc.). Those practically needed values, i.e. load characteristics can be found, based on the mathematical model. In [150] different load characteristics and their applications for long- and short-term planning of a power system operation in different conditions like low or high outdoor temperature, probable deviations of load, different load change scenarios, etc. are observed.

Load characteristics can be divided into two categories: primary characteristics and derived characteristics. The primary characteristics are directly attained from the mathematical model and, accordingly, the derived characteristics are attained by combining primary characteristics by simple arithmetic relations. For example, mathematical expectation *E(t)* and load trend *A*(*t*) are primary characteristics as long-term expected value at normal temperature and short-term load forecast are considered as derived characteristics.

The most substantial primary load characteristics are summarized in Table 4.1. By improving the mathematical model and application other primary characteristics may be derived.

Table 4.1. Primary load characteristics

Mark in the text	Mark in the equation	Name
A[P]	$P(t)$	Actual load data
AR[P]	$P_{RE}(t)$	Restored load
E[P]	$E(t)$	Mathematical expectation of load
S[P]	$\sigma(t)$	Standard deviation of load
R[P]	$R(t)$	Rate of temperature dependency
TP[P]	$A(t)$	Load trend
D[P]	$\theta(t)$	Normalized deviation of load
C[P]	$S(t)\zeta(t)$	Load expected deviation
P[P]	$S(t)\pi(t)$	Load peak deviation
I[T,P]	$R(t)\gamma(t)$	Temperature dependency
I[Z[T],P]		Simulated temperature dependency
A[T]	$T(t)$	Actual temperature
Z[T]		Simulated temperature

During the load analysis, a situation where data values for some period are missing or they are unreliable, may occur. In that case, the data must be restored. Restored data AR[P] may be found on condition

$$P_{RE}(t) = \begin{cases} P(t) \\ E(t) + R(t)\gamma(t) + S(t)[\zeta(t) + \xi(t)] \end{cases} \tag{4.57}$$

Based on the condition, the missing load data is replaced by short-term expected value of load to which simulated value of residual deviation of load is added. Standard statistical methods can be used for handling the restored load data. For example, reliable daily or monthly energy values could be accurately found by summing up the restored data even then when some of the hourly data is missing.

Load mathematical expectation E[P], standard deviation S[P], rate of temperature dependency R[P] and load trend TP[P] are directly obtained from the mathematical model. Normalized deviation of load D[P] is found according to the equation

$$\theta(t) = \frac{P(t) - E(t) - R(t)\gamma(t)}{S(t)} \tag{4.58}$$

Expected deviation C[P], peak deviation P[P] and temperature dependency I[T,P] of the load result directly from the mathematical model. Values of these characteristics are normally presented in rated units, i.e. they are multiplied with load standard deviation or with the rate of the temperature dependency, respectively. The temperature dependency is founded based on the temperature or meteorologically forecasted data. When simulating the temperature data, it is possible to find the influence of the simulated temperature I[Z[T],P]. With the simulated temperature dependency it is possible to determine, for example, what could have been the load in 2001, or forecast for the 2010, if the temperature would have been or will be as it was in 1985, respectively. Simulation is also possible if the deviation is added to the mathematical expectation of temperature.

Derived characteristics are obtained by combining different primary characteristics. Most substantial derived characteristics for load analysis and forecast are:

A[P]-I[T,P]	normalized load
A[P]-I[T,P]+I[Z[T],P]	simulated load
E[P]	long-term forecast at normal temperature
E[P]+I[T,P]	long-term forecast at actual temperature
E[P]+I[Z[T],P]	long-term forecast at simulated temperature
E[P]+I[T,P]+C[P]	short-term forecast.

Here the two first and the fourth expressions belong to the load analysis and others to the load forecasting process. The expectation of load may be used both for analysis and forecasting. Characteristic E[P]+I[T,P] is not actually forecast, but a value, which can be used for analysis and was beforehand named as expected load. The above presented equation of normalized load, from where the temperature dependency is removed from the actual data, corresponds to normal temperature. Simulated load corresponds to the given temperature in simulation conditions.

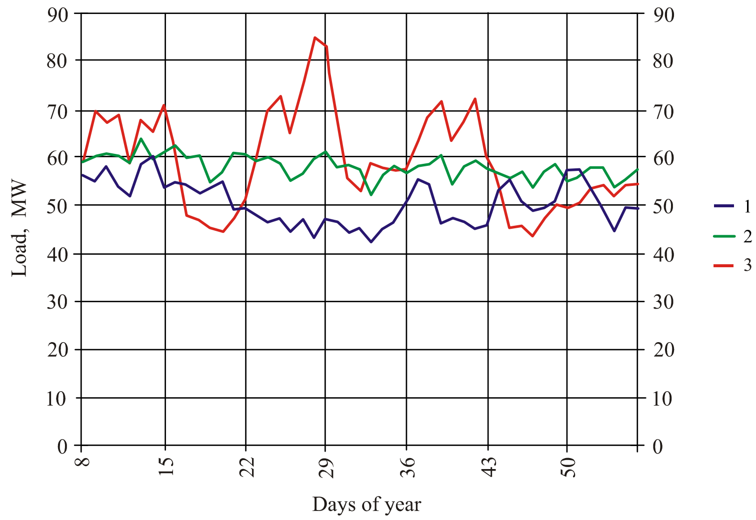

Figure 4.19. Load actual value (1), normalized value (2), and simulated value (3), daily values

In Fig. 4.19 actual, normalized and for comparison simulated load that correspond to the cold winter conditions are presented. Considering that in the long-term forecasting of load the reliable temperature forecast is missing one can substitute it with a simulated value.

At the examples above the load was in a magnitude of hundred megawatt. The stochastic deviations of loads of that type are somewhat small and therefore their regularities are well observable. In Fig. 4.20 and Fig. 4.21 loads with magnitude of some kilowatts on weekly and hourly level are presented.

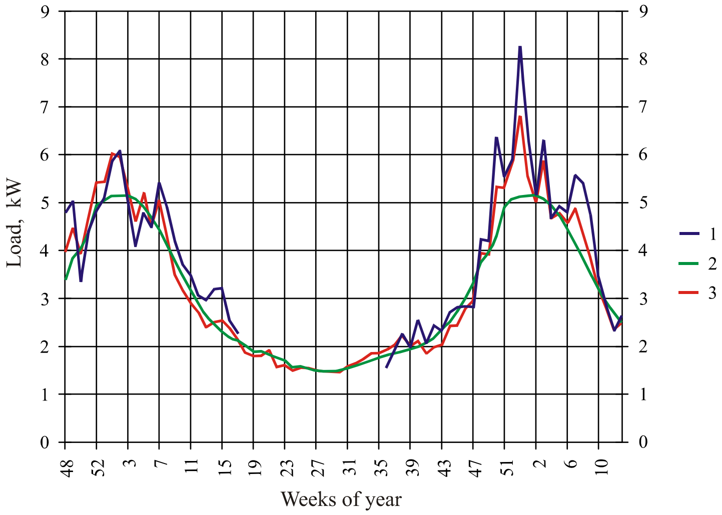

Figure 4.20. Load actual value (1), mathematical expectation (2), and expected load (3), weekly values

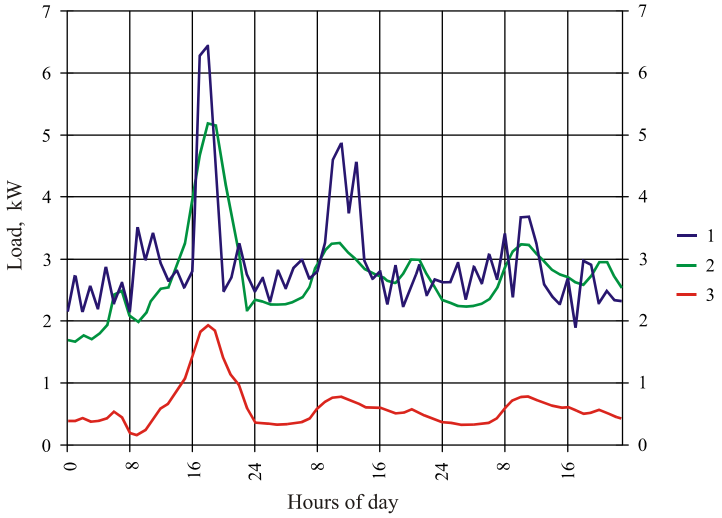

Figure 4.21. Load actual value (1), mathematical expectation (2), and standard deviation (3), hourly values

The influence of temperature is well observable. In Fig. 4.21 it could be noticed that the load peak is on Saturday evening and may be caused by the use of sauna. The peak of standard deviation at the same time indicates irregular use or connection of sauna.

5 MODELLING AND ESTIMATION OF DISTRIBUTION NETWORK OPERATION

5.1 Estimation of distribution network load model

From the point of view of practical application of the mathematical model for distribution network monitoring purposes, the estimation of model parameters is essential. The principle is that all model parameters of the load must be evaluated. The simplified models, due to a lack of load data, are not observed. Different means of estimation are possible depending on the extent and amount of initial data, but also the necessary accuracy of the model. The purpose of estimation is that the model corresponds to the given load. However, the nature of the practically necessary load characteristics (short-term or long-term forecast, etc.) is not considered during the estimation.

When modelling and estimating the electrical network load and operation one must consider the availability of initial data. In distribution network, compared to transmission network the availability of data is somewhat modest and the modelling and estimation is more complicated. In addition, the nature of distribution network load is more irregular and stochastic. The research results presented in this chapter are published in [I], [II]/[151], [III]/[152], [144]. Additional information can be obtained from [143].

The mathematical model of load (Chap. 4), used in the monitoring of electrical network operational dynamics, is applied to describe different types of loads. It is possible to observe total active and reactive loads of the whole power system or some region, e.g. distribution network, different bus loads, but also loads of separate consumers. The scale of power may reach from some gigawatts to some hundred watts. It is understandable, that the amount and quality of initial information is different. In case of large loads, time series, where active and reactive power values are fixed hourly or more frequently, are available for many years. On the other hand, in case of private consumers or planned industry consumers it is possible that only one number, yearly energy demand, may be available.

The structure of the mathematical model is the same for all loads. In order to use the load model to describe the specific loads, the model parameters must be estimated. Mathematical model includes a large number of parameters (amount of 1000). The modelling principle is that in any case all those parameters must be assessed for each load. If initial data does not allow to estimate all model parameters then only a part of parameters are directly obtained on the ground of available data. Remaining parameters are transferred form type model, i.e. from some previously estimated load model, which in its nature corresponds to observable load. Irrespective of initial information, the result is always a complete model that describes all necessary details of the load.

However, the accuracy of the model and its applications is dependent on availability of initial data and on the quality of type models. If there is enough data available, e.g. hourly data for some years, and they are of necessary quality, then it is possible to estimate a unique model for every load. No computational obstacles thereby exist. However, type models are often needed. The main reason is insufficiency of initial data due to unavailability of data or in case, there has been a remarkable change in the nature of the load, whereby earlier data is not applicable. The necessity to implement type models may rise even when enough load data is available. For example, in distribution network, where the stochasticity of load is high, type models may enhance the reliability of model parameters.

The hierarchy of model parameters contributes to the use of type models. Actually, some model parameters are relatively unchangeable in time. Other parameters are more dependent on the change of the load nature. The parameters belonging to the first group are determined during the initial estimation of load models, i.e. during load research. Those parameters may principally be classified and used as type models, i.e. if necessary they may be used in other load models. The second group consists of parameters that are more adapted to a certain load and ought to be estimated according to the specific load data. Those parameters should be adjusted separately for every load.

Principally, whatever load model, parameters of which are known, may be used as a type model. However, transfer of parameters form a type model may not happen randomly. It is necessary that the nature of the loads is somewhat similar. The concept of similarity here is different from the traditional concept. The similarity of the shape of the load curve and of course the level of load (trend) may not be essential, because those properties may be considered even with a small number of parameters, which are estimated separately according to each load.

In the approach presented here, a possibility of using the main parameters of the same model, i.e. model co-ordinates, for different loads is observed. New loads, for which earlier models are absent and available load data is insufficient, and the above mentioned modelling of distribution network operation are considered as applications.

Model parameters, named model co-ordinates (Chap. 4.3.2), include vector functions $\mathbf{M}(h)$ and $\mathbf{N}(t)$, and matrices $\mathbf{G}_r$. The second group, named model factors, include parameters a_{lr}, b_{lr}, c_{lr} (shape factors) and a, b, c and other factors related to trend (level factors). The reason of the above described grouping is due to the fact, that the level of load and shape of the load curve is, first of all, determined by model factors even if the model co-ordinates do not change. Therefore, the idea accrues that one possibility to specify type models is transferring model co-ordinates from one model to another. It is also possible to estimate model co-ordinates mutually using multiple load data, whereas model factors are found separately for every specific load. Besides model co-ordinates, sub model components of the load temperature dependency and stochasticity, $\gamma(t)$, $\zeta(t)$, $\xi(t)$ and $\pi(t)$, may be observed as typical.

To investigate the composition and field of application of type models we observe 18 loads of 5…240 MW for 2…12 years. At first, the models are estimated uniquely, separately for each load data. Afterwards, based on all load data, the model mutual co-ordinates are estimated and model factors, based on specific load data for each load, are found.

The results of the estimation of mathematical expectation are summarized in Table 5.1. Here P describes average value of load and S is the average value of standard deviation. Deviations are found between the load values, normalized regarding the temperature, and mathematical expectation $\Delta P(t) = P(t) - \Gamma(t) - E(t)$. Values dP and dS indicate the increment of standard deviation ΔS due to the use of mutual co-ordinates – $dP = \Delta S/P$ and $dS = \Delta S/S$. From Table 5.1 it appears that the error, due to the transition of the type co-ordinates is mostly below 1% at load average values and in the order of 10% at load standard deviation. These errors should be considered as acceptable.

Table 5.1. Estimation errors of mathematical expectation

Number	1	2	3	4	5	6	7	8	9
P MW	4,5	4,9	8,6	10,8	14,6	18,0	18,3	18,4	29,1
S MW	0,3	0,4	0,6	0,8	1,0	1,2	1,0	1,0	1,9
dP%	0,6	1,1	0,6	0,6	0,6	0,4	0,5	0,6	1,3
dS%	8,1	14,2	8,9	9,0	9,3	5,6	8,4	12,0	20,5
Number	10	11	12	13	14	15	16	17	18
P MW	47,0	64,7	113,4	121,4	130,0	158,7	185,7	195,0	240,0
S MW	3,0	3,5	6,3	4,8	8,6	7,1	8,3	9,4	12,6
dP%	0,2	0,5	0,5	0,6	0,6	0,5	0,8	0,5	0,5
dS%	3,0	9,6	8,9	14,7	9,8	12,7	18,2	9,8	9,4

Beside the average values of errors, it is interesting to see to what extent it is possible to represent different curves (mathematical expectation) of the load, using the type co-ordinates. In Fig. 5.1, Fig. 5.2 and Fig. 5.3 an examples of normalized values of three loads and corresponding mathematical expectation values are presented.

It is evident that in the same co-ordinates it is possible to represent different shapes of mathematical expectation curves. When observing a longer period of changes of load, e.g. a year, it is possible to notice that the values of mathematical expectation, based on a unique model and the values, based on a type model are practically identical. It should be emphasised that the mathematical expectation is found based on previously described relations, and model factors are estimated as averages up to the whole observable data interval (2…12 years).

The actual values of load are presented here only for comparison. Of course, when using the model for load forecasting, the adjustment of model factors (for example, once a year) is possible. During the forecasting, the actual values of load are used only for calculating deviation $\zeta(t)$, which, if added to the mathematical expectation in the form of $E(t) + \Gamma(t) + S(t)\zeta(t)$, gives the short-term forecast of the load.

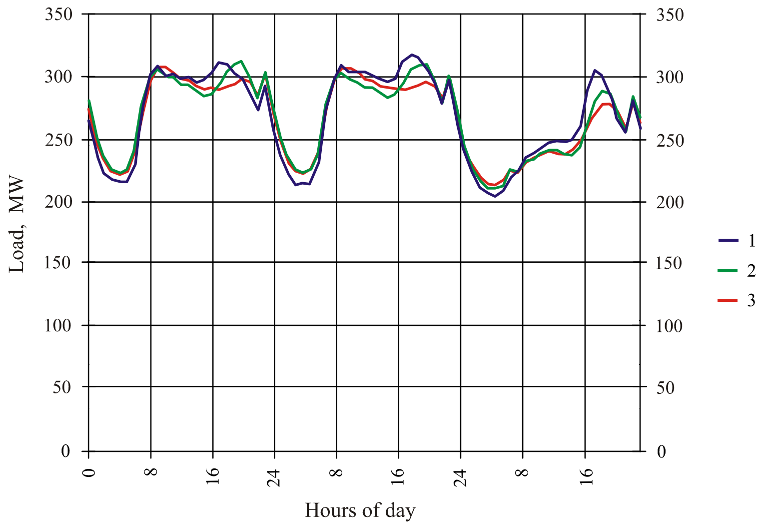

Figure 5.1. Normalized value of load number 18 (1), and mathematical expectation based on unique model (2) and type model (3)

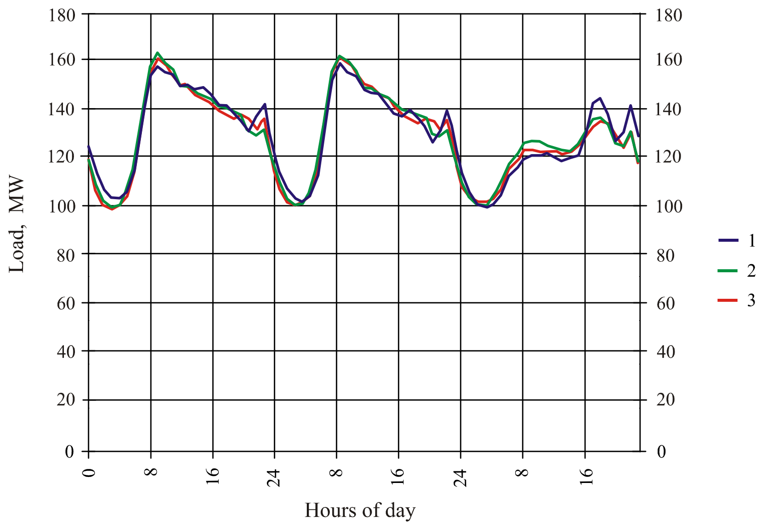

Figure 5.2. Normalized value of load number 15 (1), and mathematical expectation based on unique model (2) and type model (3)

In addition to mathematical expectation, also temperature dependency and standard deviation of load offer interest. The importance of temperature dependency may be high in some cases. In Fig. 5.4 an example of temperature influence on the load (number 18 at Table 5.1) in winter period is presented. The average values of temperature influence vary in an interval between -60…+90 MW, which forms 62% of the average value of a load. Daily average values of temperature influence, which are calculated based on a unique model and a type model, practically coincide here.

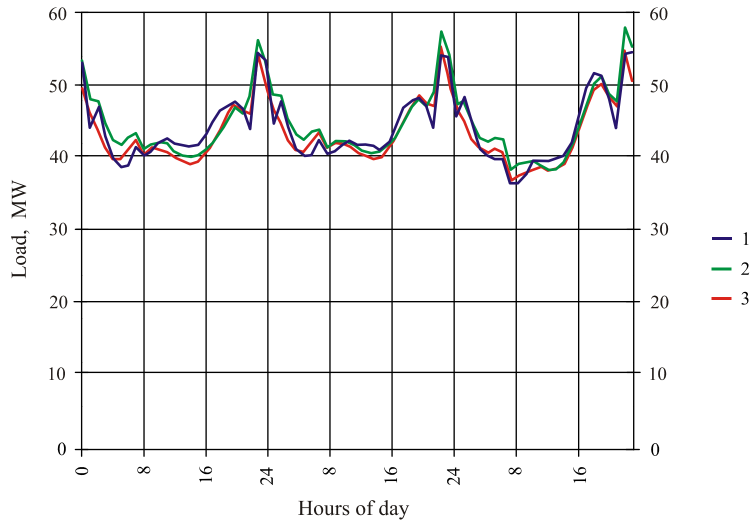

Figure 5.3. Normalized value of load number 10 (1), and mathematical expectation based on unique model (2) and type model (3)

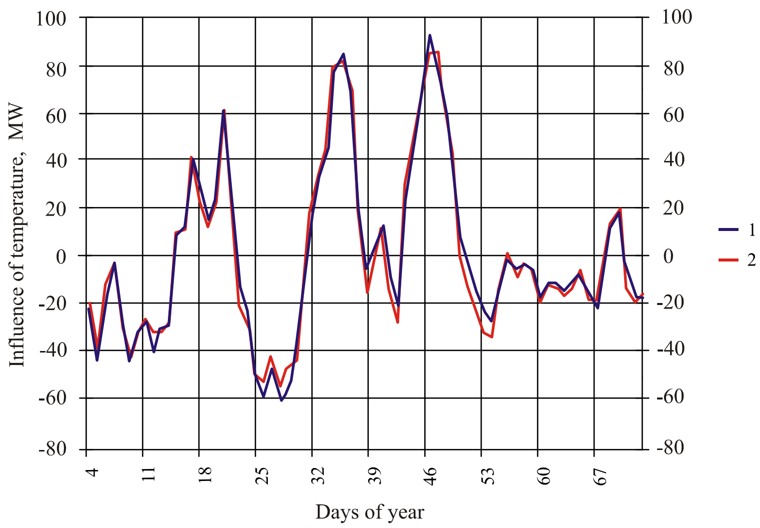

Figure 5.4. Daily average values of temperature influence based on a unique (1) and a type model (2)

However, it is not possible to generalize the obtained results for any loads. For every specific case the load research should be performed in order to determine which loads can and which cannot be modelled in the same co-ordinates. Nevertheless, it could be declared that the accepted co-ordinates may be used for a relatively long period of time (decades), while only adjusting model factors from time to time. However, unique models, which are estimated separately according to every specific load, give more accurate results to a certain extent and are therefore preferable, if enough high quality load data is available.

When estimating the electrical network load model it is also important to take into account the changes of the load on special days like national holidays, days before and after holidays etc. The number of special days depends on calendar and country and also on expected accuracy of the mathematical model. The total number of special days in a year will achieve from 30 to 60, which is about 10…15% from the total number of all days. In addition, it is also needed to observe the special periods like winter and summer holidays etc, when the load deviates from normal level during one or more weeks.

During the estimation, the load on a special day is compared to the load of the corresponding reference day that is the most similar one to the special day. The reference days are usual weekdays, for example, Sunday for a holiday, Friday for a pre-holiday workday, Monday for a post-holiday workday, etc. The mathematical expectation and temperature dependency of the load, which are calculated on the base of the reference day, are sometimes exact enough for a special day. For more precise modelling, the ratios between the loads on special days and mathematical expectations of corresponding reference days are observed. For example, in Fig. 5.5 the relation curves between the loads on the first of January, normalized by temperature $P'(t) = P(t) - \Gamma(t)$ and mathematical expectations of corresponding reference day (Sunday) are presented for five different years. On the base of the mean relation curve (curve 1 in Fig. 5.5) the elements of the matrix $\mathbf{G}_{El}$ are found (Chap. 4.3.2), which correspond to the given type of a special day.

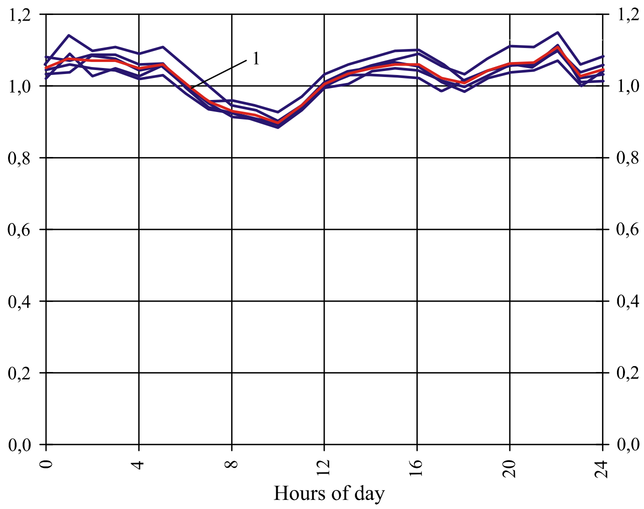

Figure 5.5. The load relation curves on New Year's day

The load of the special periods, like winter and summer holidays, could also be observed on daily basis. But practically it would be unreasonable. Moreover, during those periods the change of the level of the load is noticed not the change of the daily load curve. Because of that it is reasonable to add a corresponding component to the load trend. Hence, the load trend for one year can be presented by the relation as follows

$$A(t) = P_0 \left(1 + \alpha(t - t_0) + \sum_k \beta_k \exp\left[-\left(\frac{t - t_k}{T_k} \right)^2 \right] \right) \tag{5.1}$$

Here P_0 is the calculated value of the load at the beginning of the year. The component $\alpha(t - t_0)$ describes the linear trend of the load starting from the beginning of the year. The last part of the Eq. 5.1 adds relatively short (week or more) dips to the trend. Location, amplitude and level of dips are determined by parameters t_k, T_k and β_k. The dips of the load, which may also be positive, may be applied only to the workdays. In Fig. 5.6, for example, the linear fractional representation of the load trend for the five years is presented. It is possible to notice the dips on summer holyday periods. Although the dips are here only a small percentage of the load level, it is obligatory when the modelling is more accurate.

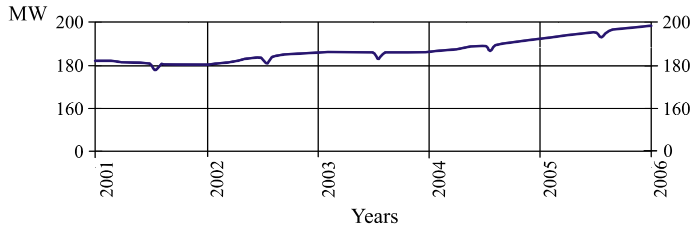

Figure 5.6. Load trend for years 2001…2005

When estimating the distribution network load possible load cases should be considered (Chap. 4.4). The load cases are considered through different sets of model parameters, each of which is valid for certain time intervals. Those time intervals are determined during the load research. With different load cases the level factors of the model change. If the shape of the load curve also varies, then the shape factors of the model must change too.

5.2 Monitoring of distribution network operation

Monitoring of the distribution network operation consists of analysing, forecasting and simulation. The network operation is determined based on different conditions and possible contingencies and their influence in case of available network configuration. The results of the research of distribution network operation monitoring, presented in this chapter, are published in [II]/[151], [III]/[152], [153], [154]. Additional information is available in [155], [156].

Modelling and analysis of distribution network operation is needed for short- and long-term operational planning of the electrical network. It is necessary to describe adequately changes in time, temperature dependency, probable deviations of the state variables and cover different cases and scenarios. Based on the results obtained it is possible to make more economical and technical decisions to obtain more efficient operation of the distribution network and enhance network reliability.

The distribution network operation is considerably influenced by network bus-loads, which are formed by active and reactive power of the substations. The availability of information is somewhat modest in distribution networks and therefore comprehensive methods for network load monitoring should be used.

The integration of the mathematical model of the load with the procedures of the operation computation may occur on different levels. In the transmission network, where the operation calculation is based on bus voltage, the values of the loads occur only as initial data. In the distribution network, the busloads may be taken as independent state variables. Incidentally, it enables the distribution network operation to be estimated even when it would otherwise be impossible due to the modest redundancy of the data. It is possible to go even further – to model the distribution network operation variables (load flows, currents, and voltages) similarly to loads. Based on the model it is possible to obtain characteristics, which enable to forecast, simulate, and analyse the operation for longer periods of time without performing extensive computations of the network state.

The principles of the methodology of monitoring of the distribution network operation are concisely presented in Fig. 5.7. Monitoring consists of network representation, gathering information, estimation of the load model, network operation modelling and estimation, verification of results and models, and adequate decision making, considering the obtained results based on different conditions. The origins of monitoring are mathematical models of load, the electrical distribution network and electrical network load. The results of the monitoring process can be used for network dispatching and for short- and long-term planning purposes.

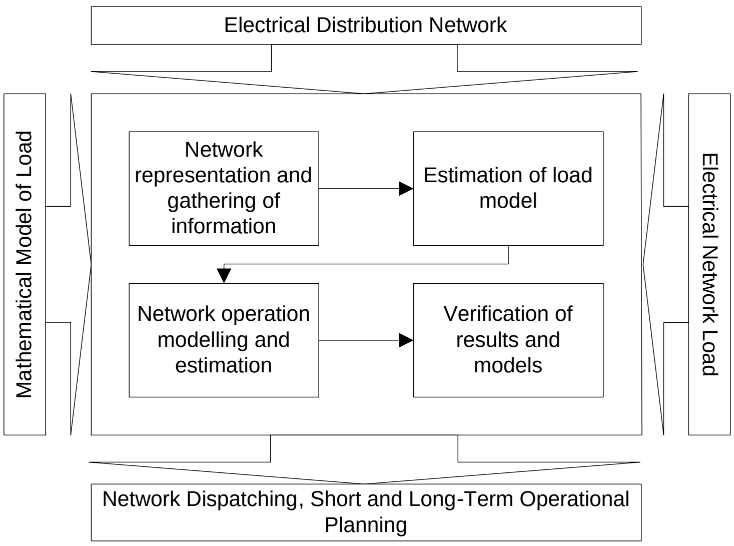

Figure 5.7. Principle diagram of the methodology of monitoring of distribution network operation

The medium voltage (MV) distribution network can be represented as a set of feeders going out from a HV/MV substation, consisting of line parts, capacitor banks and distribution substation connected to the end of MV feeders (Fig. 5.8). Modelling of different distribution network elements is observed in Chap. 3.2.

Switching disconnectors located at the disconnection points can change the configuration of a feeder. Hence, distribution network has radial structure and its functioning is directly specified by loads and their regularities. In addition, MV/MV substations and voltage regulators may be incorporated. The load of a MV feeder is formed by active and reactive loads of distribution substations. The load of a distribution substation is formed as the sum of LV loads and losses of distribution transformers.

Information on the distribution network may be obtained from different information system. However, one must consider that the lower the voltage level the less information is available. Distribution network state variables are periodically measured by dispatching system *SCADA*. State variables are mainly measured in HV/MV and in some MV/MV substations. In MV/LV substations the state variables are periodically not measured and information on network operation can be obtained through control measurements or energy metering system measurements.

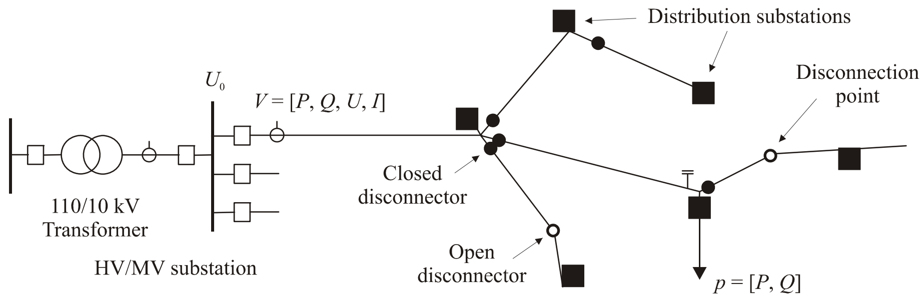

Figure 5.8. Principal scheme of distribution network

From the viewpoint of availability of the measurement data, the distribution network may be divided into operatively observable and unobservable parts (Fig. 5.9). In the observable part of the distribution network, the data that can be used for handling the network operation is obtained by the dispatching system (*SCADA*). *SCADA* gathers active and reactive power, currents and voltages of a feeder in HV/MV substations and at various points of the feeder. The sampling frequency in the *SCADA* is usually once or more times per minute. Similar data for the lower-level distribution network (the unobservable part of the distribution network) is not available. Measuring hourly electricity consumption of consumers for commercial purposes of the electricity market has recently expanded significantly. Unfortunately, the operative connection between different measuring systems is missing. However, the commercial data may also be used for estimating the load models. When even the commercially measured data is missing, load models can be estimated according to the data from the client information system.

The distribution network operation is calculated by feeders. The initial values used are the HV/MV substation voltage and the busloads. To determine the distribution network operation a simple, two-way iteration process is used (Chap. 3.3). First, the power losses and power transmission in lines are found starting from the busloads at the end of the feeder. As an initial value of the bus voltage, the nominal voltage may be used. In the second phase, the bus voltages are calculated, starting from the HV/MV substation bus, the voltage of which is considered as given. In the second phase of the calculation, the load dependency on the voltage and the effect of the voltage regulators are considered. The described algorithm usually converges in 2…5 iterations.

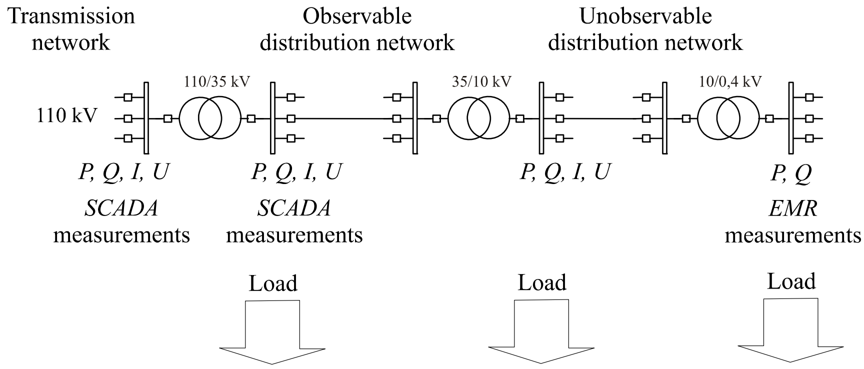

Figure 5.9. Loads on the various levels of electrical network

The calculation of the unobservable distribution network operation does not differ essentially from the calculations in the observable part of the network. The network configuration is radial, and the necessary information concerning the load is received from similar load models, as in the higher level of the distribution network. Problems could arise when obtaining the necessary load data for estimation of the model. On the unobservable level of the distribution network, the on-line measurement data is not available. The necessary load data is gathered from a different information system in off-line mode.

Difficulties may arise when determining the load cases, because an operative information exchange between different levels of the network may not occur, not to mention communication between the network and factories. Here it is possible to apply the simulation, where the load characteristics are determined and the network operation is calculated for different load cases. That way, the possible limits of the operation are achieved.

To calculate and analyse the distribution network operation different load characteristics in different conditions should be found and used. Change of load induces the change of the values of system variables, e.g. voltages, currents, active and reactive power etc. and consequently new operational state is obtained and behaviour of the system is different. The necessary load characteristics can be found using the mathematical model of load. Possible load characteristics to be used in the analysis and planning of distribution network operation could be, for example, load data in restored, normalized and simulated forms, long-term forecast, maximal and minimal values of the load, etc (Chap. 4.5). Restored load is the same as actual load there, where the hourly data is available and reliable. Elsewhere, the data is interpolated or simulated. Normalized load describes the actual load without temperature influence. Simulated load corresponds to some simulated temperature. The temperature may be simulated when finding the temperature dependency of the loads based on the temperature from another year, which may offer some interest (cold winter, etc.) in analyzing and forecasting loads. Short-term forecast of the load is found as a sum of mathematical expectation, temperature influence and expected deviation. If comparing the expected values of the operation parameters (calculated based on expected value of load) with measurements, it is possible to notice sufficient accordance or difference between measured and calculated data. The load characteristics may be found based on different load scenarios. Examples and practical implementation of mathematical model of load for distribution network operation monitoring is presented in Chapter 6.

Changes of the feeder configuration do not obstruct the operation monitoring if the actual or expected configuration of the network is known. The possible feeder configuration changes are fixed by the dispatching system and checked in the operation estimation process. Configuration changes in the low voltage network are not observed by the dispatching system. The results may be rapid changes of the medium voltage network busload values, which are observed as load cases. The load cases are connected only with the planned changes. The emergency cases are not observed. Just as between the transmission network and distribution network, the loads of the observable part of the distribution network are formed in the unobservable part. The possible specification of the load cases is important. The adjustment of the model factors for different load cases may also be carried out on the basis of observable network data.

The final part of the methodology consists of verification of results and composed models. To receive adequate results for different system studies the results obtained through modelling process should be comparable to the measurement results obtained through measurement systems. It is understandable that errors in the measurements exist and consequently mistakes may appear, but on the other hand the above described methodology offers an opportunity to clarify bad data and compose reliable load and network models to be used in system studies. As the redundancy of data required for estimation is usually not available, traditional estimation methods are not directly applicable in distribution networks. Therefore, mathematical model of load offers a unique solution for enhancing the accuracy of distribution network analysis and planning (Chap. 5.3).

The efficiency of the monitoring methodology depends on the accuracy of the load model, which, in its turn, results from the regularity of the change of the loads. Hence, the practical application of the monitoring methodology requires clarification. It may be assumed that the medium voltage network operation estimation is not feasible for the purpose of increasing the accuracy of the measurement data. Nevertheless, it may be possible to determine whether or not the operation fits with the load and network model. The appearance of exceptional states may be presented as events in network dispatching, which also establishes that the network operational computation on current data is not adequate. Later (on the next day, e.g.), the exceptional states must be specified, and the load and network models should be adjusted as needed.

The model adaptation algorithm and method for detecting bad data and exceptional loads need to be clear. The operation of the voltage regulating equipment also complicates the monitoring methodology. Nevertheless, the monitoring methodology may be applied in both offline and online data processing. The limitations (due to the computer resources) are not foreseen, as the excessively complex computations are missing.

5.3 Distribution network state estimation

The target of state estimation is to refine measuring data. It is especially important to clarify significant measuring errors or mistakes. Due to the insufficiency of information and measurement data, the traditional estimation methods used under conditions of main grid are not directly applicable in distribution networks. For getting required additional data load models are used [143]. The results of the research presented in this chapter are published in papers [VI]/[157] and [VII]/[158].

5.3.1 Technique for distribution network state estimation

Calculating of feeder state parameters is based on network equations through main operating parameters – supply voltage and node loads

$$V_j(U_0, p_1, p_2, \ldots p_n) \tag{5.2}$$

Symbol p_i corresponds here both to active and reactive powers. So the general number of loads n is equal to double number of nodes and so there are $n + 1$ main operating parameters $U_0, p_1, p_2, \ldots, p_n$.

Supposing, that for considered moment there are m measurements $\widetilde{V}_j$ (P, Q, U or I), it is possible to obtain refined operating parameters (refined measurements) V_j from the criterion

$$\sum_j \left[\widetilde{V}_j - V_j\right]^2 = \min, \; j = 1 \ldots m \tag{5.3}$$

As in distribution networks the needed data redundancy does not exist in most cases – the number of measurements m does not essentially exceed the number of main operating variables $n + 1$, or is even smaller. For resolving this problem the boundary conditions are applied, which demand that the deviations of state parameters have to be as small as possible

$$\sum_i \Delta^2 p_i = \min, \; i = 1 \ldots n \tag{5.4}$$

In other words, it is needed that the state of the network would be as close as possible to that, which is forecasted by means of the load models.

Let us see the network equations being linearized over main operating parameters, when marking $p_0 = U_0$

$$\Delta V_j = \beta_{0j}\Delta p_0 + \beta_{1j}\Delta p_1 + \beta_{2j}\Delta p_2 + \ldots + \beta_{nj}\Delta p_n \tag{5.5}$$

where

$$\beta_{ij} = \frac{\partial V_j}{\partial p_i}, \; i = 0...n \tag{5.6}$$

In the form of matrix

$$\mathbf{\Lambda} = \mathbf{B\Delta} \tag{5.7}$$

where

$$\mathbf{\Lambda} = \left[\Delta V_0, \Delta V_1 ... \Delta V_m\right] \tag{5.8}$$

is the vector of deviations of measurement data

$$\mathbf{\Delta} = \left[\Delta p_0, \Delta p_1 ... \Delta p_n\right] \tag{5.9}$$

is the vector of deviations of main state parameters

$$\mathbf{B} = \begin{vmatrix} \beta_{10} & \beta_{11} & \cdots & \beta_{1n} \\ \beta_{20} & \beta_{21} & \cdots & \beta_{2n} \\ \cdots & \cdots & \cdots & \cdots \\ \beta_{m0} & \beta_{m1} & \cdots & \beta_{mn} \end{vmatrix} \tag{5.10}$$

is the sensitivity matrix (Jacobean)

Here the deviations Δp_i are found on the base of the expected values calculated by a load model (short-term forecasts one time step ahead). It is possible to compose the mathematical model also for the supply voltage U_0. For simplicity it is the trivial model, where mathematical expectation and standard deviation of voltage are constant.

For finding elements of the sensitivity matrix **B** it is necessary, at first, to assign the deviations of the model parameters $\Delta p_0 ... \Delta p_n$. Then to find the corresponding load values and at last to calculate the deviations ΔV_j of considered state parameters on the base of non-linearized network equations. As a result

$$\beta_{ij} = \frac{\Delta V_j}{\Delta p_i}, \; i = 0...n, j = 1...m \tag{5.11}$$

Let us see the extended vector of deviations of measured data

$$\widetilde{\mathbf{\Lambda}}_0 = \left[\Delta\widetilde{V}_1, \Delta\widetilde{V}_2 ... \Delta\widetilde{V}_m, 0, 0 ... 0\right] \tag{5.12}$$

in which the n last components are zeros. Next, matrix $\mathbf{B_0}$ with $n + 1$ columns, where on the first m rows there are elements of sensitivity matrix **B** and on the next n there is a zero vector and a unit matrix, is composed.

$$
\mathbf{B}_0 = \begin{vmatrix} \beta_{10} & \beta_{11} & \dots & \beta_{1n} \\ \beta_{20} & \beta_{21} & \dots & \beta_{2n} \\ \dots & \dots & \dots & \dots \\ \beta_{m0} & \beta_{m1} & \dots & \beta_{mn} \\ 0 & 1 & \dots & 0 \\ 0 & 0 & \dots & 0 \\ \dots & \dots & \dots & \dots \\ 0 & 0 & \dots & 1 \end{vmatrix} \tag{5.13}
$$

The above-mentioned conditions are simultaneously satisfied, if

$$
\left(\widetilde{\mathbf{\Lambda}}_0 - \mathbf{B}_0\mathbf{\Delta}\right)^T \left(\widetilde{\mathbf{\Lambda}}_0 - \mathbf{B}_0\mathbf{\Delta}\right) = \min_{\mathbf{\Delta}} \tag{5.14}
$$

From here, a system of linear equations over the deviation vector $\mathbf{\Delta}$ follows

$$
\mathbf{B}_0^T \mathbf{B}_0 \mathbf{\Delta} = \mathbf{B}_0^T \widetilde{\mathbf{\Lambda}}_0 \tag{5.15}
$$

The deviation vector $\mathbf{\Delta}$ allows to refine all state parameters – it is possible to calculate both the specified measured parameters (estimates) and whatever other operating parameters.

5.3.2 Execution of state estimation

The results of state estimation are authentic, if there is no bad data and exclusive states are not observed. If bad data is obtained, they have to be removed and the estimation procedure must be repeated. It is also possible to attempt to define the exclusive states more closely. If the exclusive state is still unclear, the estimation of this state is not possible and the measurements of this moment are not used. As a result, dispersion of the expected value of load increases to a certain degree, but in principle this does not obstruct the process of estimation.

During the estimation the following situations will take place:

- measurements are correct
- some bad data occurs
- load cases are changed
- the exceptional state occurs.

If deviations of measurements are within tolerance limits, the state calculations can be done somewhat more accurately. Nevertheless, because of the insufficiency of the measurements and the stochasticity of a distribution network states, the rising of accuracy is not essential. It is more important that the network operation proceeds within tolerance limits and measuring data can be considered as correct.

Essential deviations in single measurements indicate measurement errors. Typical errors include the functioning faults of measuring transducers or telecommunication channels. Usually these faults are not disclosed by *SCADA*, because all of individual operating parameters remain within tolerance limits. That is the reason why such kind of faults may occur during a long period of time. In that case the estimation can provide reliable operating values and indicate the necessity for checking the measuring system.

The aim is to disclose bad data and exclusive loads one by one or as scenarios. Errors among measured data may be combined with one another, for example due to telecommunication line interference. The symptoms of exclusive situations are detected by rating the load deviations and the elements of the sensitivity matrix. Bad data detection and identification problems in the distribution networks are partially similar to the problems in the transmission networks [127]. The essential difference lies in the fact that in case of the given estimation methodology the prospective state is known (forecasted).

In addition to regular changes, temperature dependency and stochastic nature, electrical busloads may also change unevenly, whereas the changed level of load and also possibly changed load character is maintained over a longer time period. Those situations are considered as load cases, which may be caused, for example, by switching in lower level network, commissioning or stopping of large electricity consumers (factories), switching of reactive power compensation equipment, etc (Chap 4.4).

In given situations it is always possible to clarify the probable values for operating parameters and verify that the operation is ordinary and expected or not. Nevertheless, in some cases the checking of operating parameters can be difficult due to faulty conditions or in case of unordinary loads. Faulty conditions will be verified by *SCADA*. Unordinary loads can be researched offline in order to clarify the new unknown load cases.

5.3.3 Editing of load models

Successful application of the estimation method depends on adequacy of the mathematical load model, which requires relevant estimation of load model parameters. It is possible to adjust (adapt) load model parameters during the estimation of a distribution network operation.

Let us see the node loads p_i with parameters of the model $a_{i1}, a_{i2}...a_{ir}$ at the moment t_k

$$p_i(t_k, a_{i1}, a_{i2} ... a_{ir}), \ i = 1...n \tag{5.16}$$

where r is the number of parameters that have to be estimated.

Next the network equations are presented

$$V_j = V_j(U_0, p_1, p_2, ... p_n) \tag{5.17}$$

describing the state parameters via the parameters of the load model

$$V_{jk} = F_{jk}(a_1, a_2, ... a_l), \ j = 1...m \tag{5.18}$$

where $l = nr$ is the overall number of the parameters of all load models. The function F_{jk} corresponds to the moment t_k on which the load values and supply voltage depend.

The parameters of the load model are calculated from the criterion

$$\sum_j \sum_k \left[\widetilde{V}_{jk} - V_{jk}\right]^2 = \min \tag{5.19}$$

where $\widetilde{V}_{jk}$ is the measuring data at the moment k.

Network equations, linearized over the model parameters, are

$$\Delta V_{jk} = \alpha_{1jk}\Delta a_1 + \alpha_{2jk}\Delta a_2 + \ldots + \alpha_{ljk}\Delta a_l \tag{5.20}$$

where

$$\alpha_{sjk} = \frac{\partial V_{jk}}{\partial a_s}, \ s = 1 \ldots l \tag{5.21}$$

In the form of matrix

$$\mathbf{\Lambda}_k = \mathbf{A}_k \mathbf{\Delta} \tag{5.22}$$

where

$$\mathbf{\Lambda}_k = \left[\Delta V_{1k}, \Delta V_{2k} \ldots \Delta V_{mk}\right] \tag{5.23}$$

is the increment vector of measured parameters

$$\mathbf{\Delta} = \left[\Delta a_1, \Delta a_2 \ldots \Delta a_l\right] \tag{5.24}$$

is the increment vector of model parameters

$$\mathbf{A}_k = \begin{vmatrix} \alpha_{11k} & \ldots & \alpha_{1lk} \\ \ldots & \ldots & \ldots \\ \alpha_{m1k} & \ldots & \alpha_{mlk} \end{vmatrix} \tag{5.25}$$

is the sensitivity matrix (Jacobean)

If the vector of metering deviations is

$$\widetilde{\mathbf{\Lambda}}_k = \left[\Delta \widetilde{V}_{1k}, \Delta \widetilde{V}_{2k} \ldots \Delta \widetilde{V}_{mk}\right] \tag{5.26}$$

then the deviations for model parameters are calculated from the criterion

$$\sum_k \left(\widetilde{\mathbf{\Lambda}}_k - \mathbf{A}_k \mathbf{\Delta}\right)^T \left(\widetilde{\mathbf{\Lambda}}_k - \mathbf{A}_k \mathbf{\Delta}\right) = \min_{\mathbf{\Delta}} \tag{5.27}$$

that gives the system of linear equations over the vector $\mathbf{\Delta}$

$$\sum_k \left(\mathbf{A}_k^T \mathbf{A}_k\right)\mathbf{\Delta} = \sum_k \mathbf{A}_k^T \widetilde{\mathbf{\Lambda}}_k \tag{5.28}$$

The base for linearizing the network equations is the load values, calculated by load models (expected values of load). Relative to the same values metering deviations are found. Linearization is acceptable, if the metering deviations are not too large. Otherwise it is necessary to use the iterative process, according to which the deviations are added to the model parameters and new state parameters and metering deviations are calculated. In this connection repeated linearization (calculation of the new sensitivity matrix) is not needed and it is possible to continue with the old matrix. The elements of sensitivity matrix are calculated as follows

$$\alpha_{sjk} = \frac{\Delta V_{jk}}{\Delta a_s},\ s = 1...l, j = 1...m. \tag{5.29}$$

The number of measuring data must be larger than the number of parameters being estimated. For example, if the number of the loads is 10 (5 distribution substations), parameters 10 and measurements 10, then the number of the required values is l = 100 and so more than 10 metering hours are needed. Therefore the daily metering is enough to get the results. But the authenticity of results is a separate question. It is clear that the model, estimated on the base of the data of one or some days, is not usable for a longer period. For example, the data of winter loads is not representative for summer loads. Generally it is an adaptation problem, which can be resolved taking into account the essential meaning of the model parameters.

The degree of the equation system, obliged to be resolved, is high (for the above-mentioned example it is 100). It means that the volume of calculations is too large and it may mean that the equation system is poorly conditioned. The way out is to use the results of state estimation, by means of which the node loads are always found independently from the structure of measured state parameters. Consequently, it is possible to receive all load values, state parameters and edit the parameters of all load models. If m = 1 and $l = r$ we can get

$$\mathbf{A}_k = \left|\alpha_{1k}\ ...\ \alpha_{rk}\right| \tag{5.30}$$

$$\mathbf{\Delta} = \left[\Delta a_1, \Delta a_2\ ...\ \Delta a_r\right] \tag{5.31}$$

$$\widetilde{\mathbf{\Lambda}}_k = \left[\Delta \widetilde{V}_k\right] = \widetilde{p}_k \tag{5.32}$$

$$\sum_k \left(\mathbf{A}_k^T \mathbf{A}_k\right)\mathbf{\Delta} = \sum_k \widetilde{p}_k \mathbf{A}_k^T \tag{5.33}$$

where $\widetilde{p}_k$ is the estimated value of the observed load at the moment k. The degree of the equation system is now r or for the above-mentioned example it is now 10, and problems about calculation volumes are removed.

The efficiency of the estimation method depends on the accuracy of the load models and therefore it is important that both the state estimation and the editing of load models will take place. Thus, the models always correspond to the real situation in the distribution network.

Using the above-described method, it is possible to clarify how the network operation is compatible with both the load and network models and, if the network operation is ordinary or not. It is possible to present exceptional operation like events and assure that the performed computations based on available data are adequate. Though the deficit of needed data does not allow refining the measuring data, it is still possible to clarify the faulty measurements.

6 AN APPLICATION OF LOAD MODEL IN MONITORING OF DISTRIBUTION NETWORK OPERATION

In this chapter, an application of the load model for monitoring of distribution network operation is presented. For modelling and analysis and for the assessment of the presented methodology a small operatively observable part of Estonian distribution network was selected. The research consisted of modelling the load (load model estimation), calculation of the network operation based on various load characteristics and estimation of the distribution network operation.

For practical application of the mathematical model of the load, a computer program must exist. In this research a program package *Elmo* (*Electrical Load Monitoring*), which is based on *ActiveX* type code component *ElmoExe.dll*, is used. Component *ElmoExe.dll* performs all the procedures related to the estimation of load models and calculation of the load characteristics. Data processing with component *ElmoExe.dll* is based on the mathematical model of the load. Since the structure of the mathematical model is the same for all loads, the program component is also useable in all application programs. Operations, associated with the user interface are not included in the component. Component *ElmoExe.dll* does not use any external data sources. Necessary load data and model parameters are saved into buffer files, which are only at disposal of component *ElmoExe.dll*. The whole necessary accessibility to the external databases and user interface is the responsibility of the application programs. Component *ElmoExe.dll* does not deal with that.

Research related to the handling of the loads is performed by the program *ElmoSet*, which is based on the component *ElmoExe.dll*. The program *ElmoSet* offers a necessary user interface and enables the storage of load data into buffer files. In addition, an application program *ElmoDisco*, which performs the necessary calculations of the electrical network, including the state estimation, is used. The program *ElmoDisco* is also based on the component *ElmoExe.dll*.

6.1 Description of example network

The example network, named *Pandivere*, used in this research, is a part of Estonian 35 kV distribution network. The network consists of three HV/MV and six MV/MV substations connected with overhead lines (Fig. 6.1). In the MV/MV substations two transformers are present but depending on the load one of them may be in reserve. In the selected network four disconnection points are present and they separate the mesh network into three feeders, which for the analysis of network operation are observed separately.

When executing the possible switching in the network, e.g. changing of location of the disconnection point due to maintenance or fault, the feeder configuration also changes. For example, the disconnection point at line L-C3 in substation three may be changed to substation two or four and disconnection point at line L-45 at substation four may be located at substation three, etc. In this research we observe only the normal scheme of the distribution network because the consideration of different network operative changes does not change the physical nature of applied methodology.

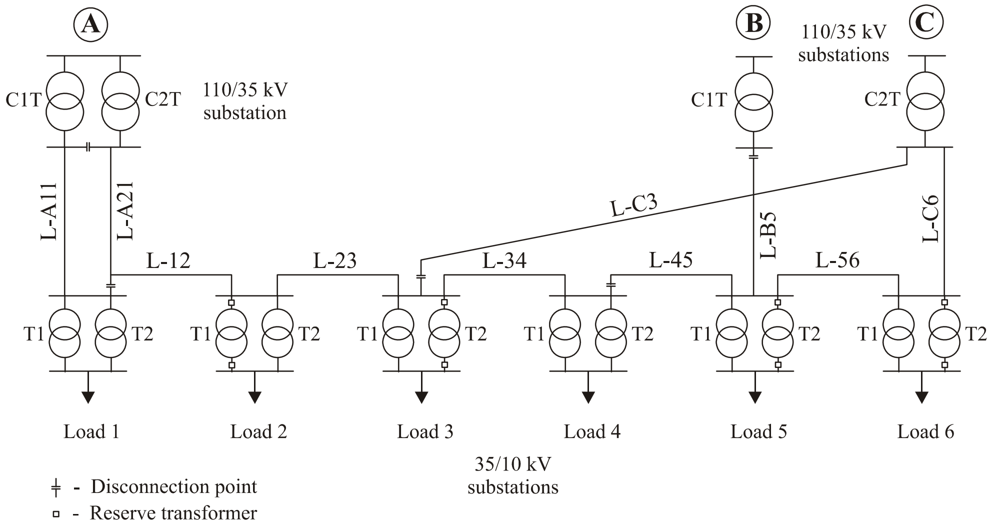

Figure 6.1. Principle diagram of the example network

The considered distribution network is operatively observable and it is monitored by distribution network *SCADA*. At HV/MV substations measurements of bus voltages, feeder active power, reactive power and currents are selectively available. In MV/MV substations values of overhead lines currents, busbars voltages and transformer active and reactive power values are measured. In substations five and six mainly busbar voltages and transformer active and reactive power measurements are available. The available data interval is once an hour.

Information on observable distribution network overhead lines and transformers is presented in Table 6.1 and Table 6.2, respectively. Values of overhead lines types, lengths, resistances, inductances and different transformer parameters are given.

Table 6.1. Parameters of overhead lines

Line	Type	Length (km)	R (Ω)	X (Ω)
L-A11	AS-120	2,80	0,70	1,09
L-A21	AS-120	2,15/0,65	0,54/0,16	0,84/0,25
L-12	AS-95	17,12	5,65	7,02
L-23	AS-95	11,72	3,87	4,85
L-34	AS-70	15,75	7,04	6,57
L-45	AS-70	14,48	6,21	5,82
L-56	AS-70	9,98	4,28	4,06
L-B5	AS-70	32,56	13,97	13,9
L-C3	AS-95	23,45	7,17	9,56
L-C6	AS-70	12,97	5,56	5,27

Table 6.2. Parameters of transformers

SS	T	S_N (MVA)	U_N (kV)	I_N (A)	u_k (%)	R (Ω)	X (Ω)
1	T1	4	35/10,5	66/220	8,73	-	26,74
1	T2	4	35/11	66/210	7,7	-	23,58
2	T1	2,5	35/10,5	41,2/137,5	6,05	-	29,65
2	T2	2,5	35/11	41,2/131	6,8	-	33,32
3	T1	4	35/10,5	66/220	6,47	1,98	19,81
3	T2	2,5	35/11	41,2/131	6,6	-	32,34
4	T1	2,5	35/11	41,2/131	6,64	-	32,54
4	T2	4	35/11	66/210	7,2	-	22,05
5	T1	4	35/10,5	66/220	8,39	2,82	25,69
5	T2	4	35/10,5	66/220	9,3	3,08	28,48
6	T1	6,3	35/10,5	104/346	7,18	1,44	13,96
6	T2	4	35/11	66/210	7,28	2,56	22,30
A	C1T	16	115/38,5	80,3/240	10,6	0,56	9,82
A	C2T	16	115/38,5	80,3/240	10,12	0,77	9,37
B	C1T	10	115/38,5	50,2/150	10,0	1,03	14,8
C	C2T	25	115/38,5	125,5/375	10,8	0,32	6,40

The observed part of the Estonian distribution network is mostly located in the middle of Estonia. Substation one is located completely in an urban area and substations three to six have to deliver electrical energy to both urban and rural area consumers. The loads consist mainly of household and small workshop consumers, no large industries are present. The magnitude of the distribution network MV/MV substations' active and reactive power is 0,5…5 MW and 0,2…1,5 MVAr, respectively. Magnitude of the total load at HV/MV substation feeders reaches form 10 A to 90 A depending on season and possible switchings in the network.

6.2 Estimation of network load

The example network consists of six loads with active power in the magnitude of some megawatts and reactive power about one megavar. Load data in the form of active power, reactive power, voltage and current have been collected for six years (2003…2008). Hourly data on temperature for the same period is also used. Such notable amount of initial data is principally sufficient for estimating the unique model for every observable load. However, it must be considered that the nature of distribution network loads is rather stochastic. Moreover, measurement errors (mistakes) also appear due to errors of measurement transducers.

Estimation of the load models starts from the evaluation of model co-ordinates (Chap. 4.3.2), which includes vector functions $\mathbf{M}(h)$ and $\mathbf{N}(t)$ and matrices $\mathbf{G}_r$. For different reasons, the model co-ordinates may be estimated as mutual (typical) for certain group of loads (Chap. 5.1). Finding of typical co-ordinates is mostly rational also in the case of distribution network loads. It also appeared in this research that the certainty of estimation of model co-ordinates is higher when the mutual co-ordinates are found based on the data of all six active loads. The reactive power is modelled in the same co-ordinates but the data is not used in the estimation process due to low level and relatively large stochasticity of reactive power. The form of model co-ordinates corresponds to the co-ordinates presented in Fig. 4.2 and Fig. 4.3.

The model factors, which include shape factors a_{lr}, b_{lr}, c_{lr}, and level factors a, b, c and other factors related to the trend, also shape factors of mathematical expectation, standard deviation and rate of temperature dependency, may be possibly estimated as unique, separately for every active and reactive load. The problem here is that possible load cases and dips (Chap. 4.4) influence substantially the estimation of level factors. When finding the model shape factors such problems may not appear because those factors must be changed only when the nature of the load (shape of the load curve) changes. In the observed network this kind of load changes were not noticed and therefore the shape factors remain unchanged for the whole observable period of time (six years).

The load trend is represented as linear fractional when the time period is relatively long. In the case of absence of load cases and dips, for example for the load number three, the trend is similar to the curve presented in Fig. 6.2.

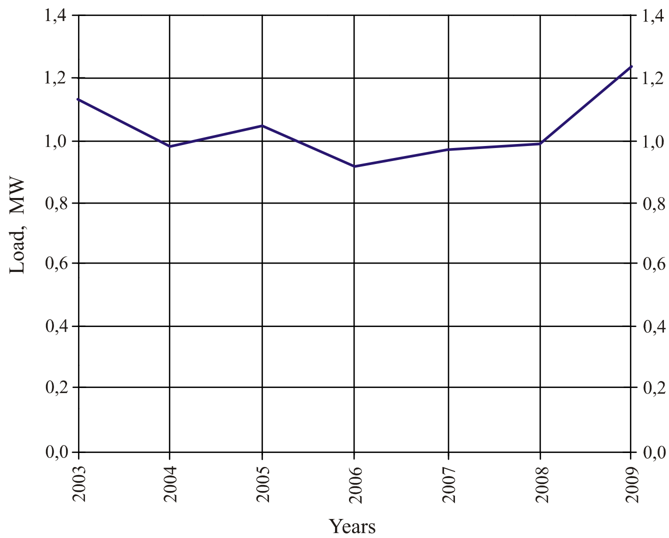

Figure 6.2. Trend of load number three

Load cases that are mostly related to the switchings on the lower level networks are expressed as saltatory changes on the level of trend, starting at some specific time moment. In Fig. 6.3 trend of load number one is presented. The saltatory change on the trend level is expressed as corresponding change of the mathematical expectation of load (Fig. 6.4).

The drop of the load level for longer period of time (few weeks) is considered as load dip. In the observed example network the load dips were present in case of load number four during the summer periods at 2005…2008 (Fig. 6.5 and Fig. 6.6).

Those dips can be explained as collective holiday in local company. Dips related to the end of the year could be observed also for other observed loads.

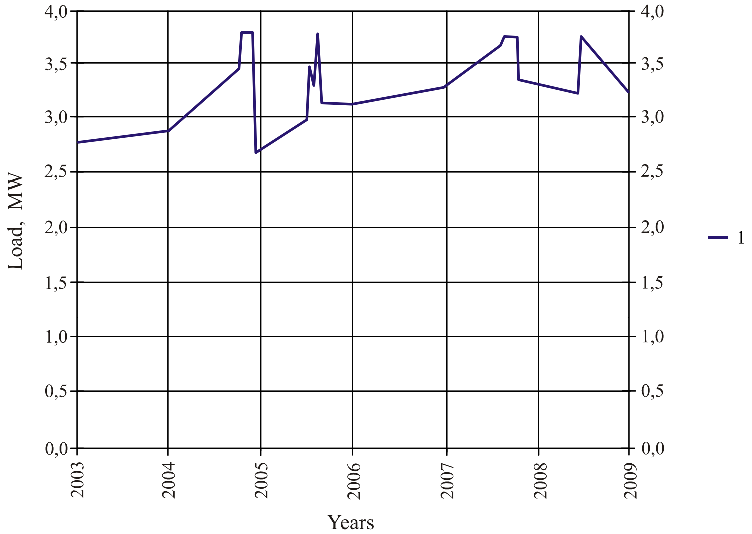

Figure 6.3. Trend of load number one

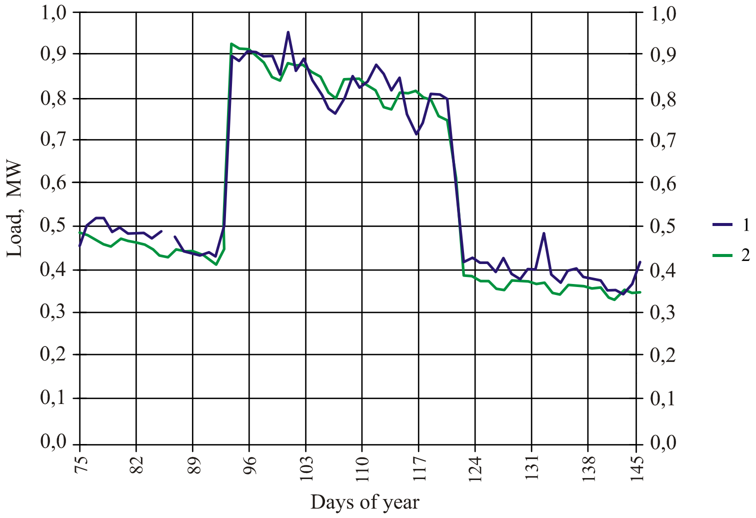

Figure 6.4. Normalized load (1) and mathematical expectation (2), daily values

As mentioned above, it is possible to find the model shape factors as uniquely for the whole period of time irrespective of load cases and dips. However, the question arises, how the common model co-ordinates enable to represent the different shapes of the mathematical expectation (also standard deviation and rate of temperature) curves. In Fig. 6.7 and Fig. 6.8 two examples of different levels and shape of load curves are presented. The coincidence of normalized load to the mathematical expectation, calculated based on the model, may be considered here as sufficient.

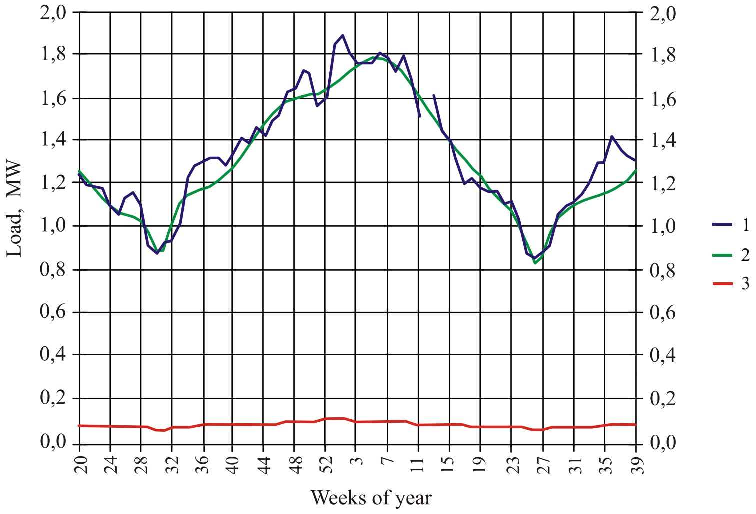

Figure 6.5. Normalized load (1), mathematical expectation (2) and standard deviation (3), weekly values

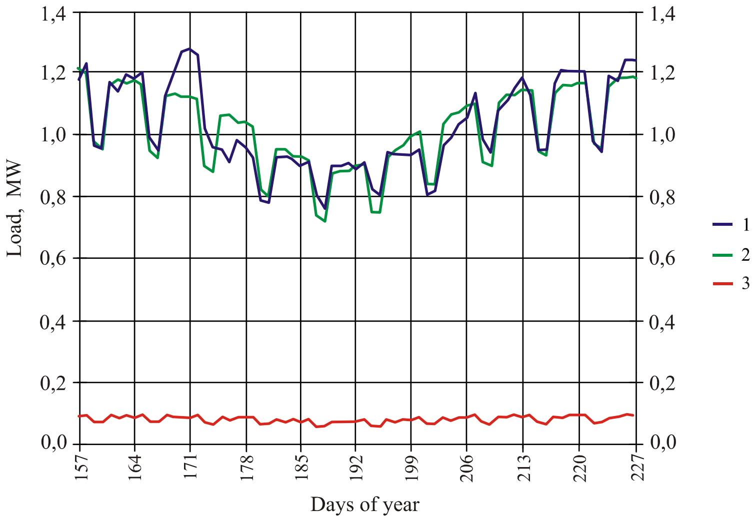

Figure 6.6. Normalized load (1), mathematical expectation (2) and standard deviation (3), daily values

The temperature dependency model of load (Chap. 4.3.3) consists of two components $\Gamma(t) = R(t)\gamma(t)$. Rate of temperature dependency $R(t)$, which belongs to the main components of model, is presented in the same co-ordinates as the mathematical expectation. Also level factors are the same, except factor b, which is found similarly to type factors, separately (as unique) for every load. Normalized temperature dependency component $\gamma(t)$ is found as typical, based on all six active load data. In case of reactive load, the temperature dependency is not observed (it is considered as absent) because the influence of temperature on the consumption of reactive power, for example, induction load, is small.

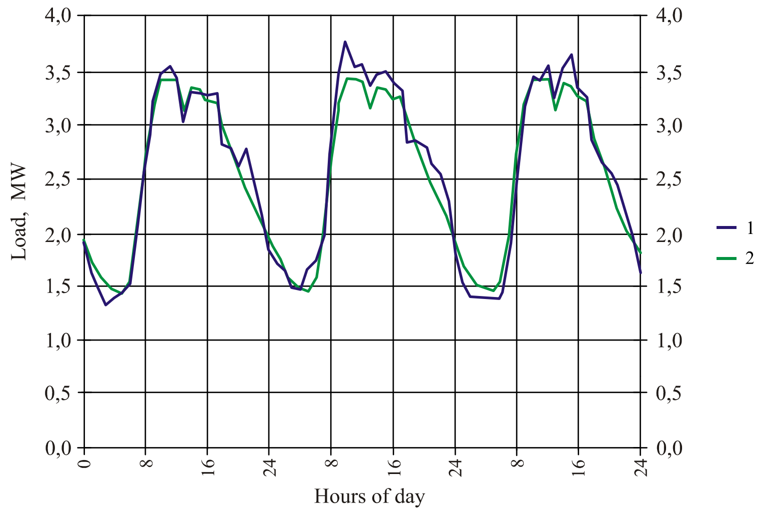

Figure 6.7. Normalized load (1) and mathematical expectation (2), hourly values

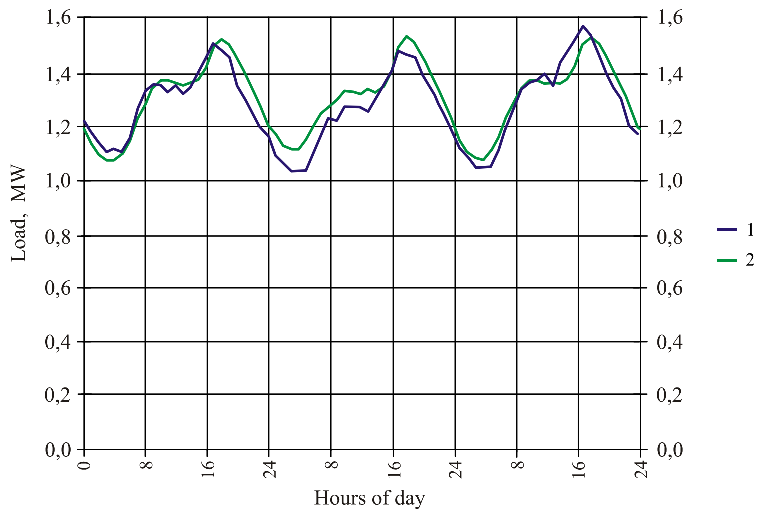

Figure 6.8. Normalized load (1) and mathematical expectation (2), hourly values

The temperature dependency of observable distribution network is not especially high because the level of small workshop load is noticeable and electrical heating is used modestly. The influence of temperature dependency is more observable in case of load number one. In Fig. 6.9 an example of that load temperature dependency, which is expressed as load decrease when temperature rises, is presented. Let us remind that the expected value of load E[P] + I[T, P] is obtained when the influence of temperature is added to the mathematical expectation. In Fig. 6.9 also temperature deviation from normal temperature (right axis), based on which the influence of temperature is obtained, is presented.

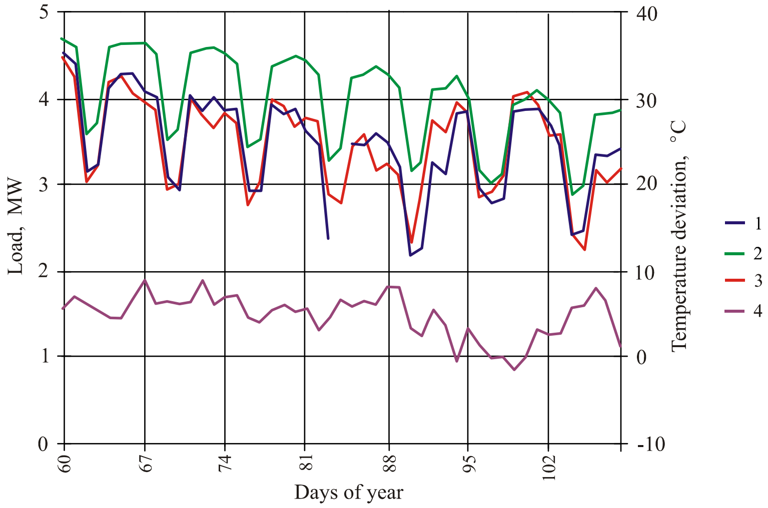

Figure 6.9. Actual load (1), mathematical expectation (2), expected value of load (3), and temperature deviation (4), daily values

Stochastic component of load $\Theta(t) = S(t)[\zeta(t) + \xi(t) + \pi(t)]$ consists of standard deviation $S(t)$, expected deviation $\zeta(t)$, white noise $\xi(t)$ and peak component $\pi(t)$. Besides standard deviation $S(t)$, in fact, the stochastic deviation of load

$$\vartheta(t) = \frac{1}{S(t)}\left[P(t) - E(t) - \Gamma(t)\right] \tag{6.1}$$

is modelled. Based on the model of $\vartheta(t)$, it is possible to find the components $\zeta(t)$, $\xi(t)$ and $\pi(t)$ (Chap. 4.3.4). Standard deviation, which belongs to the main components of the model, is estimated in the same way as the rate of temperature dependency. The model co-ordinates and the trend are the same as in the case of mathematical expectation, only trend factor a is replaced by factor c. That factor and type factors of standard deviation are found according to every different load, separately for active and reactive power. It should be emphasized that the importance of stochastic component is high when finding the short-term forecast of load. Also the expected value of load (short-term), which is used as a base for the state estimation, belongs here. It is rational to estimate the stochastic deviation $\vartheta(t)$ model parameters as typical based on all six active load data. The same stochastic deviation model is used for reactive loads, but their data is not used in the estimation process.

In addition, it is principally necessary to estimate the relation curves, which specify the values of mathematical expectation on special days (Chap. 5.1). Modelling of load on special day proceeds from the reference day, calculated values of which (mathematical expectation, temperature dependency etc.) are mostly exact enough for a special day and relation curves are not needed. In the observed distribution network the relation curves are also disclaimed. It was only necessary to compose the special day calendar, where the dates of special days and corresponding reference days, which were regular weekdays from Monday to Sunday, were presented.

6.3 Calculation of distribution network operation

Distribution network operation is calculated by feeders. In case of normal operation the observable example network is divided into three feeders as shown in Fig. 6.10. In the normal operation the lines L-C3, L-45 and L-B5 are not used for the distribution of electrical energy (Fig. 6.1). These three lines are not observed in this example because they are used only in special conditions, e.g. maintenances at substations and/or lines, faults in the system, etc. In addition, transformers that are in reserve during normal operation are not presented. The sections where the applicable state variables, e.g. active and reactive power, currents and voltages (all of them not necessarily in the same section), are measured, are in the figure marked with bold dots and with numbers in circles.

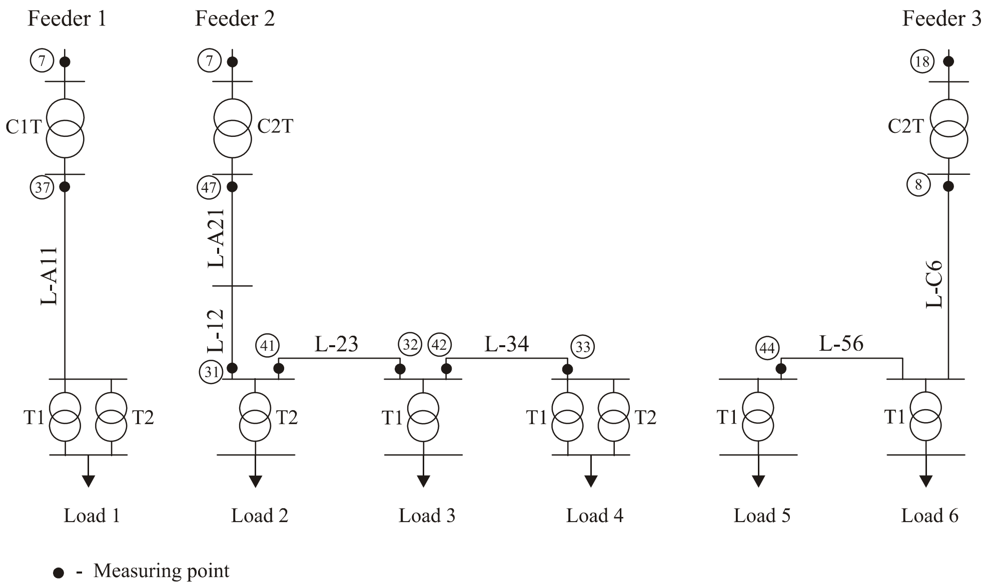

Figure. 6.10. Feeders of example network

To calculate the feeder operation, a simple two step iteration method, e.g. backward-forward loop method (Chap. 3.3), is used. There, in the first step, power losses and power flows in the lines, starting from the end of the line, are calculated and, afterwards, bus voltages, starting from HV/MV substation HV bus, are found. In the calculations the equations 3.31…3.33 and for the transformers the equivalent diagram, presented in Fig. 3.6b, are used.

The operation of feeders and the whole distribution network is principally determined by the loads, which in this example are presented in the form of active and reactive power at substations from one to six. Depending on the purpose of the calculation of distribution network operation the following load characteristics (Chap. 4.5) may be used:

- PA – actual load
- PRE – restored load
- PA – PI – normalized load
- PA – PI + PIZ – simulated load
- PE – expectation of load
- PE + PI – expected value of load (long term)
- PE + PI + PC – short-term forecast
- PE + PIZ – simulated forecast
- etc.

Restored load PRE coincide with actual load if the load data is reliable. If load data is missing or it is unreliable, the load values are replaced by short-term expected value of load (Chap. 4.5). In Fig. 6.11 an example of restored load values, in the case of load number one, are presented. It should be noticed that the feeder operation can not be calculated on the base of actual load, if even one load data is missing in the observable time period. In the case of restored load that situation does not occur. Hereafter we presume that instead of actual load PA the values of restored load PRE are used. Of course, that statement applies only for loads. The values of control measurements, which are used only for comparison, are not changed.

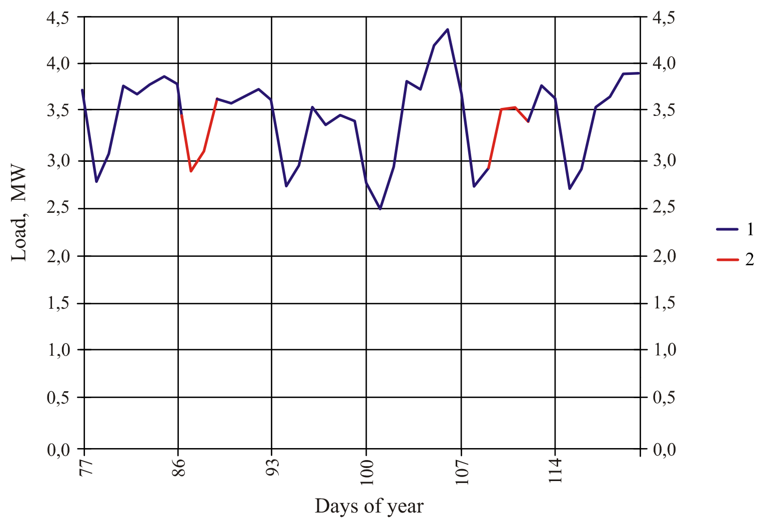

Figure 6.11. Actual (1) and restored (2) load, daily values

Normalized load PA – PI, where the influence of temperature is subtracted from real values, corresponds to the normal temperature and the simulated load PA – PI + PIZ corresponds to the simulated temperature accordingly. Let us remind that it is possible to simulate the temperature by specifying the temperature deviation in relation to the normal temperature. It is also possible to use some previous year temperature data, e.g. cold winter etc. In Fig. 6.12 an example of current in section 47 of feeder two that is found based on the real values of loads number 2…4 and on normalized and simulated (temperature deviation –10 ºC) values, is presented.

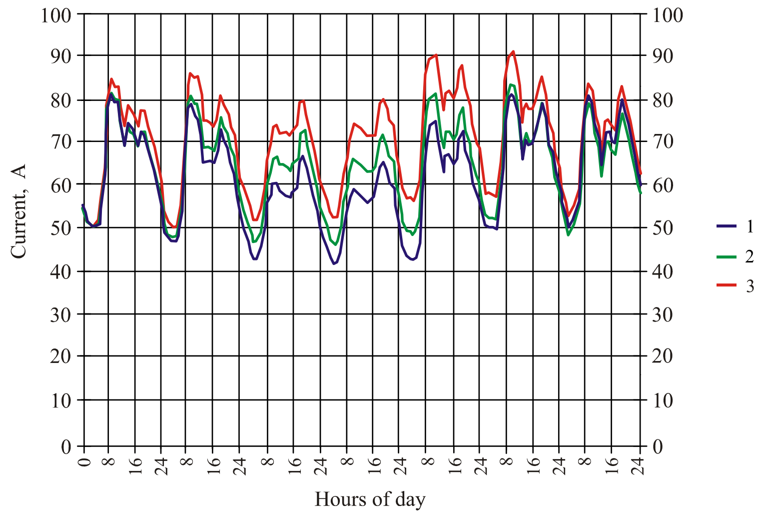

Figure 6.12. Actual (1), normalized (2) and simulated (3) current, hourly values

Expectation of load PE, which can be found for any time period for the past and for the future, may be used for analysis and forecasting of the distribution network operation. Expectation of load as a forecast means a value of load, whereon the standard deviation is missing and which corresponds to the normal temperature. In the analysis, it is more rational to rely on the expected value of load (long-term) PE + PI, where the expectation of load is added to the influence of temperature, which is found, based on real temperature values. In Fig. 6.13 an example of actual active power value compared with the mathematical expectation and expected values, which are found on feeder number three at the section 18, is presented.

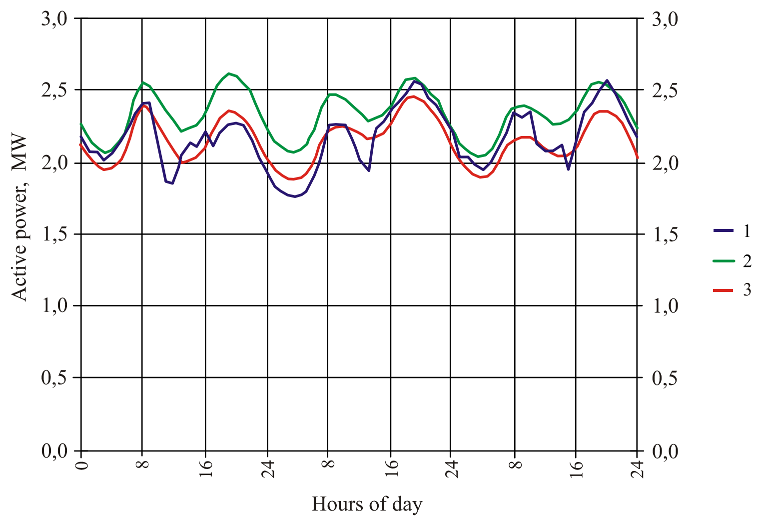

Figure 6.13. Actual value (1), mathematical expectation (2), and expected value (3) of active power, hourly values

Short-term forecast of the distribution network operation is based on the assumption of the short-term forecast PE + PI + PC of loads. Here the influence of the temperature PI is found based on meteorological forecast of temperature, accuracy of which for the nearest 1…5 days may be sufficient. The accuracy is even increased due to the 24 hour delay of temperature dependency, which, for example, means that the temperature influence for the next day is practically calculated based on real temperature data. PC indicates the expected deviation of load, which is found based on the load deviations having taken place during the last 7…10 days. In Fig. 6.14 an example of active power actual value, mathematical expectation, expected value and short-term forecast on feeder number two at section 44, is presented.

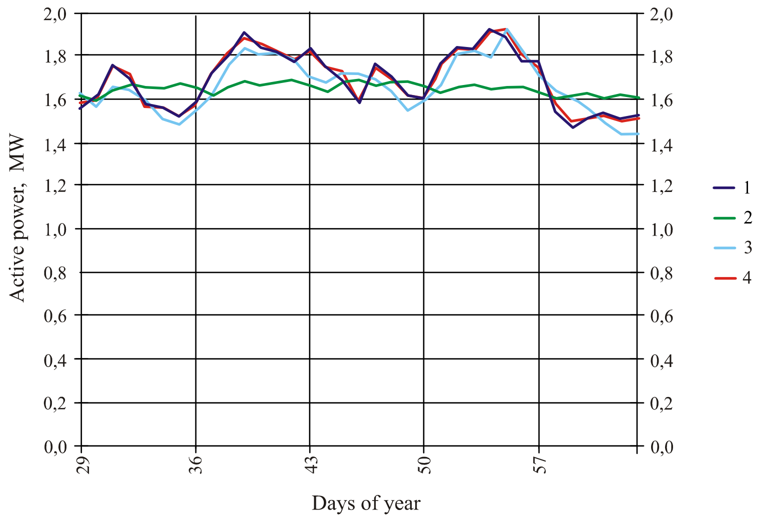

Figure 6.14. Actual value (1), mathematical expectation (2), expected value (3), and short-term forecast (4) of active power, daily values

In case of forecasting for a longer period of time (lead time week or more) it is possible to obtain the simulated forecast PE + PIZ, where the temperature values are simulated like mentioned above. In this way, it is possible to determine and predict the possible deviations of the distribution network operation in the future and plan the necessary measures to guarantee the quality of supply.

All the above mentioned operation characteristics may be found for different load cases, when analyzing and forecasting the distribution network operation. Load cases, which are causing the change of the level of mathematical expectation, should already be considered, when estimating the load models. However, in the analysis, it is possible to find the values of mathematical expectation based on different load cases and therefore determine the effect of load cases on the network operation. In the operation forecasting the load cases may be appropriately specified. In Fig. 6.15 an example of the current value on feeder number one at section 47 in the case of two different load number one values, is presented.

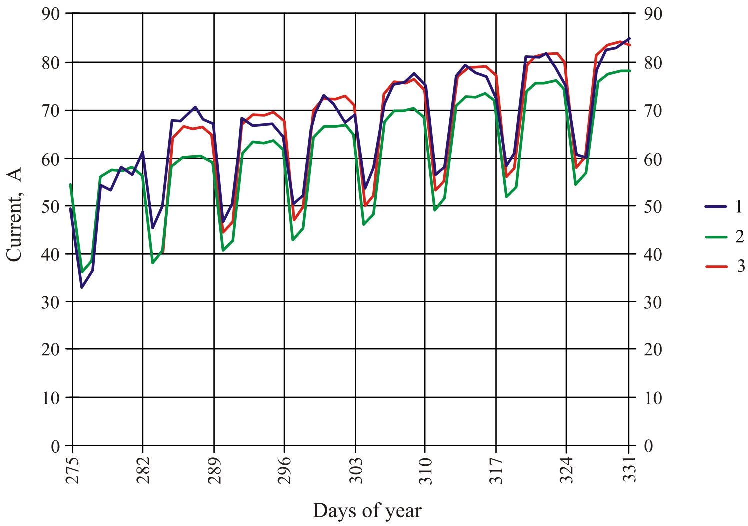

Figure 6.15. Normalized current (1), and mathematical expectation values in the first (2) and second (3) cases, daily values

To obtain the necessary operation characteristics other possibilities are available. For example, it is possible to find the boundary values of the state variables, which are caused by the stochasticity of load. For that purpose, a component ±3PS, where the PS is the standard deviation of load, may be added to the load characteristics. However, it should be considered that the normal distribution does not apply for loads (Chap. 4.3.4). Also the stochastic deviations of the feeder loads may not be in the same magnitude or even have the same direction. Due to the correlation, the load deviations are not independent and therefore a certain concurrence may still take place. Treatment of the stochasticity of distribution network operation is then a separate research topic itself and therefore it is not observed here.

6.4 Estimation of distribution network operation

The purpose of the state estimation is to assess the measuring data, remove the significant measuring errors or mistakes and give sufficient estimate of the whole network operation. For distribution networks appropriate estimation methods should be composed because the methods available for transmission network are not directly applicable due to insufficiency of measurement data. To resolve the data deficiency problem, load models are used. The estimation methodology was described in Chapters 5.3.1 and 5.3.2.

The measurement values used for the estimation of an example network operation as control factors are described in Chap. 6.3 (Fig. 6.10). More precise overview of control factors is given in Table 6.3. Here LoadID is the identification number of the measurement point (section of the feeder) and DataID is data type: 1 – active power, 2 – reactive power. 3 – current, 4 – voltage.

Table 6.3 Control factors of an example network

Feeder	LoadID	DataID	Interval of data
1	7	3	01.01.2003…31.12.2008
1	37	3, 4	01.01.2003…31.12.2008
2	31	3, 4	01.01.2003…31.12.2008
2	32	3, 4	01.01.2003…31.12.2008
2	33	3, 4	01.01.2003…31.12.2008
2	41	3, 4	01.01.2003…31.12.2008
2	42	3, 4	01.01.2003…31.12.2008
2	47	3, 4	01.01.2003…31.12.2008
3	8	1, 2, 3	01.01.2005…31.12.2008
3	18	1, 2, 3, 4	01.01.2005…31.12.2008
3	34	1, 2	15.05.2003…31.12.2008
3	43	3, 4	01.01.2003…31.12.2008
3	44	1, 2	15.05.2003…31.12.2008

The distribution network operation is estimated in the same order as the calculation of network operation, e.g. by feeders. The base for the estimation is the short time expected values of load

$$\mathrm{PE} + \mathrm{PI} + \mathrm{PC}_1 \tag{6.1}$$

i.e. the short-term forecast of load for one time interval, for example, one hour ahead. Based on the expected values of load the feeder state in given time interval for observed sections are calculated. Results are considered as expected values of control factors. Analysis of the results follows. When necessary, the state calculations may be repeated in changed conditions to determine the reasons of differences between measured and calculated values.

The limited deviation of measured and calculated values of control factors can be assessed based on standard deviation of the measurement values. The measured values may be considered as reliable, when the deviation does not exceed $c_S \times \sigma$, where c_S is confidence factor and σ is standard deviation. The value of confidence factor may be, for example, taken as 2.7. The standard deviation of load belongs to the mathematical model and it is expressed by corresponding load characteristic. Standard deviation of the current may be found through the standard deviations of active and reactive loads that are causing that current

$$\sigma_I = \frac{\sqrt{\left(\sum_i \sigma_{Pi}\right)^2 + \left(\sum_i \sigma_{Qi}\right)^2}}{\sqrt{3}kU} \tag{6.2}$$

where k is the average transformation ratio. The influence of network losses is not considered there, but that does not have any practical meaning. The value of standard deviation of voltage may be given as desired value. Since all the control voltages belong to the 35 kV distribution network, then the suitable value for standard deviation of voltage is 0.75 kV.

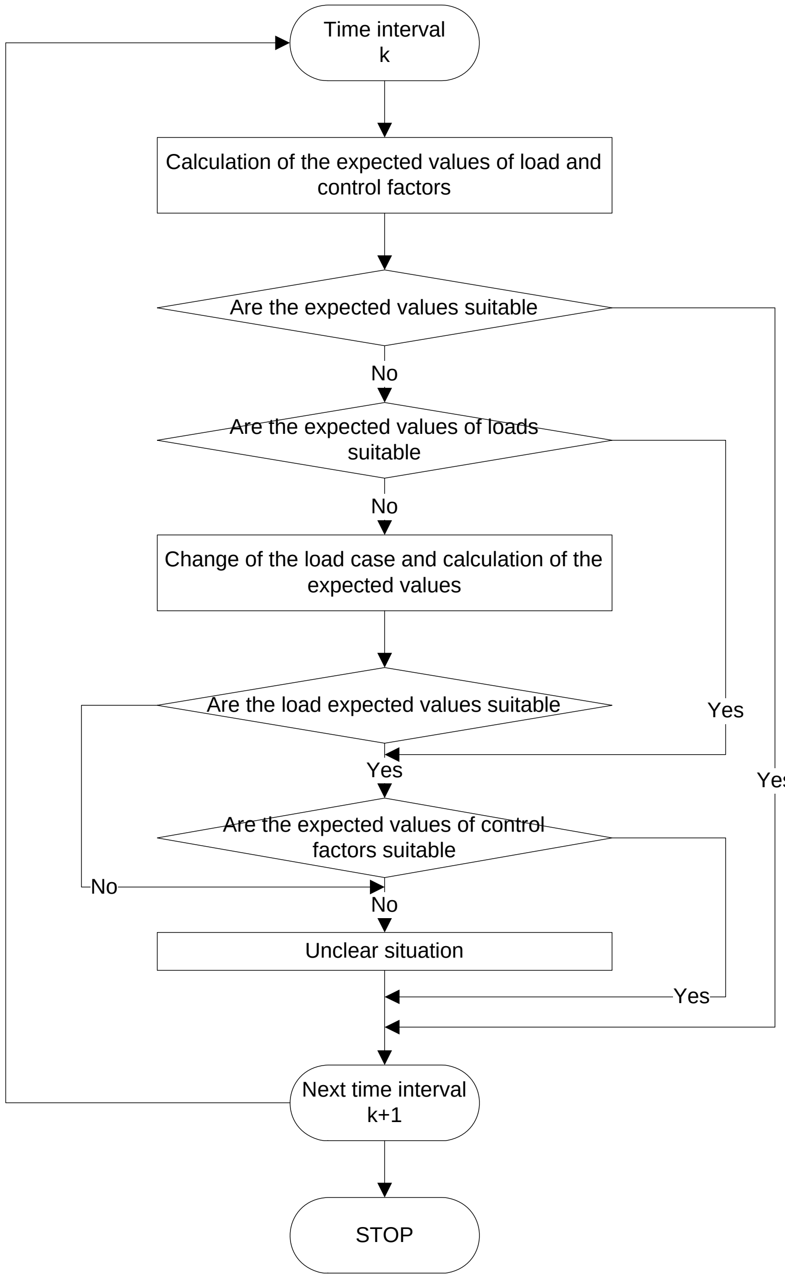

Figure 6.16. Algorithm for estimation of distribution network operation

State estimation algorithm in the simplified form is presented in Fig. 6.16. At first the expected values of load for some time interval are found and the values of state variables i.e. expected values of control factors are calculated. The next step is a check of load data and measured values. If the deviation of the measured values of loads and control factors from expected values is within limits then the measured values may be considered as reliable and the next time interval is treated.

If some of the loads or control factors differ from expected values then the following reasons are possible:

- absence of load measurement data
- measurement error of load
- load case changes
- exceptional load
- control measurement is missing
- measurement error of the control measurement
- unclear situation.

The inspection of the state starts from the loads. If the data on some load is missing then they are substituted with expected values. There is no need to repeat the calculations because the operation was already found based on expected values of load. In the case of unsuitable value of load, and when other loads and deviations of control values are acceptable, then a measurement error of load may be presumed. Especially it applies when, for example, the active power is unacceptable but reactive power of the same load is not, or vice versa. If the noticeable deviation is large both in active and reactive power but also deviation of control values then the change of the load case may be presumed. In that occasion the expected values of load based on some other load case are found and the calculation of the operation should be repeated. If the suitable load case could not be found then it may be considered as exceptional load. To determine that situation, the expected values are substituted with actual values of load and the calculations of the operation are made. If the load actual values are missing or control values are unsuitable then the network operation in that time interval should be declared as unclear.

When the situation considering the loads is clear then the values of control factors could be observed. Also the missing values may be substituted with expected values here. Excessively large deviations may be declared as measurement errors. Other operations related to the control factors are not needed because their values were already used when checking of the load data. A practical result here is the information about disorders of the measurement system. Even the unclear situation may be induced by mistakes in the measurement system. Other possible reasons are changes in the network configuration, load cases and emergency situations. For the operation estimation the network configuration and also the structure of the feeder should be given in advance. Principally, it is also possible to determine the switching through appropriate algorithm. The management and analysis of load cases should be performed by a corresponding person, load manager [143]. Only those situations that are explainable from an engineering viewpoint and may be repeated in the future are considered as load cases and appropriately modelled. Emergency situations are not treated in the estimation. The estimation algorithm will recover automatically when the emergency situation in the network is dissolved.

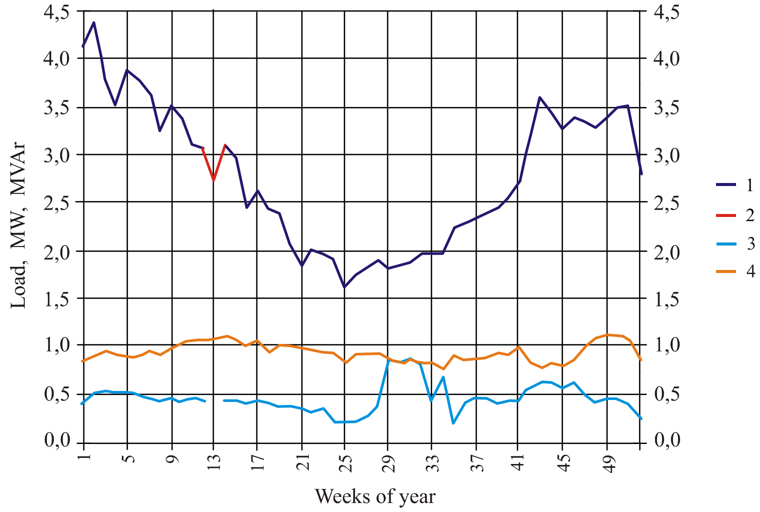

Figure 6.17. Actual values of active (1) and reactive (3) loads and corresponding estimated values (2) and (4), weekly values

The existing data and control values of an example network are mostly reliable. However, numerous measurement errors and absence of data are also present. In Fig. 6.17 an example of load number one active and reactive power and corresponding estimated values for year 2003 are presented. The estimated values are considered here as the actual values of load or control factors in the case of appropriate data and as corresponding expected value if the data is missing or if it is unsuitable. Based on the results presented in Fig. 6.17 an obvious reactive power measurement error during the whole period, except on weeks 29…32, is presented.

Figure 6.18 Actual (1) and estimated (2) value of current, weekly values

It may also be confirmed by the fact that the corresponding current control value I37 at feeder number one during that period is suitable (Fig. 6.18), except in the weeks 13 and 34, where missing of data and measurement errors were present, respectively. It should be mentioned that the weekly values are considered as missing or inaccurate, if even one hour in the week is such. Indeed, observation of hourly values revealed that in the week 13 the load value for only one hour was missing. In the week 34, the load values for four days were zero (Fig. 6.19), which practically means that the data is missing. According to the estimation methodology, it is possible to replace the unsuitable data by expected values. Therefore it may be stated that the estimation results for the feeder number one are suitable for the whole 2003, despite the fact that the reactive power measurements were incorrect almost during the whole year.

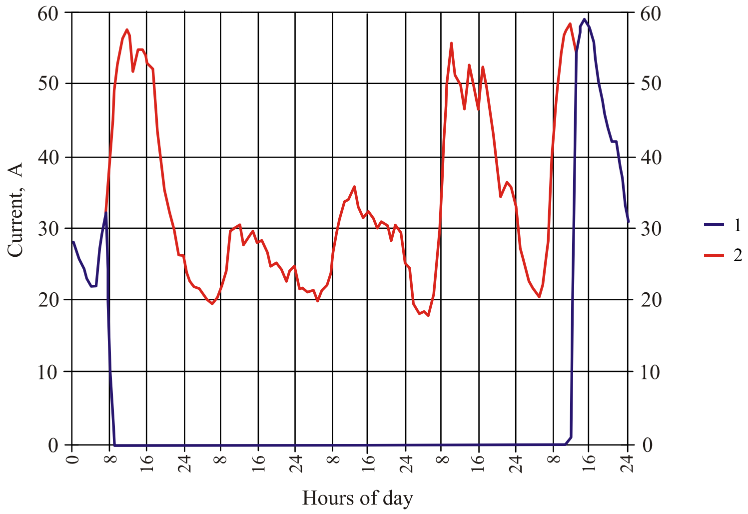

Figure 6.19 Actual (1) and estimated (2) value of current, hourly values

In Fig. 6.20 a situation, which should probably be considered as a measurement error, occurred on the third feeder at sections 18 and 44 is presented. Here the active power at section 18 is zero for 15 hours, at section 44 it is negative. It seems that the line L-C6 was switched off and the load number six was fed by the line L-56. However, firstly, the delivered power is too small and secondly, during that time period the current on lines L-45 and L-B5 through which the power transfer may happen, is missing. Similar situations for those measurements happen also later.

An example of the response of the estimation algorithm to the change of the load case is presented in Fig. 6.21. Here, due to the switchings in the lower level network on 12.12.2007 at 5 PM, the first case of load number six is substituted by the second case. Accordingly, the active power values on the third feeder at section 18 are changed. At first the estimation algorithm calculated the operation of loads number five and six according to the first case, which turned out as unfit. Afterwards the load cases are changed and it is found that the results are trustable if for load number five the first case is considered and for load number six the second case. Since 13.12.2007 at 5 PM the first load case recovers also for load number six.

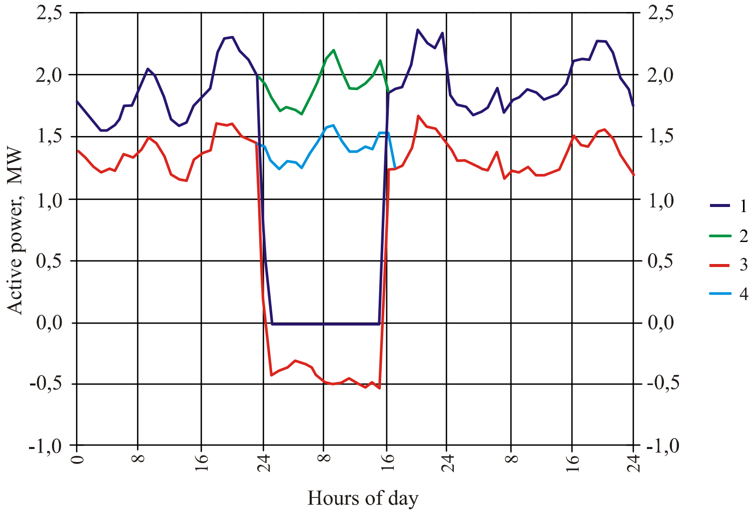

Figure 6.20. Actual values and estimates of active power in section 18 (1, 2) and section 44 (3, 4), hourly values

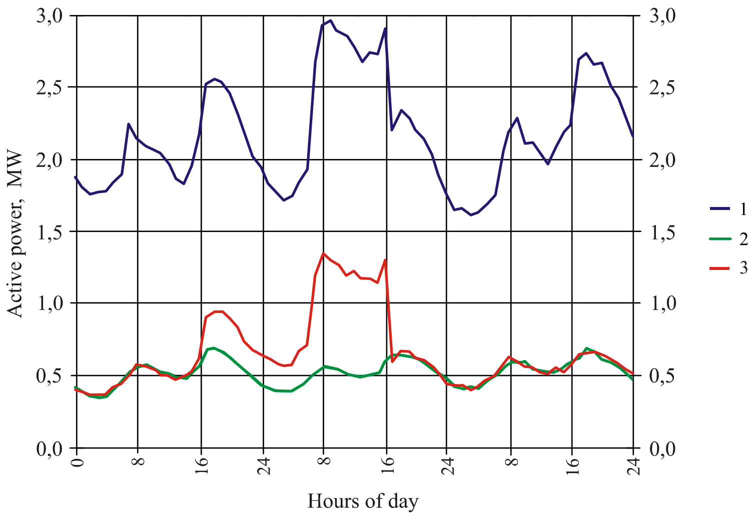

Figure 6.21. Estimated value of active power at section 18 (1), and expected value of load six in the first (2), and the second (3) load case

Besides detecting considerable errors, the estimation algorithm enables also to discover smaller deviations. In Fig. 6.22 an example of current in line L-34, measured at both ends of the line (sections 33 and 42), is presented. Those measurement values should coincide because the observable 35 kV overhead line is relatively short (16 km). However, the variance of measurement data is noticeable. The estimation algorithm declares that the measurements on feeder two at section 33 are suitable and in section 42 they are not. The second example is presented in Fig. 6.23, where the estimated active power values on feeder three at section 44 are considered as reliable (only the missing data on day 56 have been substituted), and reactive power values are not. Hence, the reason is a measurement error. Certainly the same results may also be obtained by trivial observation of the data, if comparing the measurements at both ends of the line L-34 or compare the reactive power values at section 44 and reactive power at load number six, which is bigger than the value at section 44. However, the advantage of the estimation is the detection of errors and declaring which of the measurements are reliable. Because in this thesis the adjustment of measurement values is not observed, the expected value of load I42 (Fig. 6.22), which is considered as the estimate for that current, is slightly different from the current I33 value.

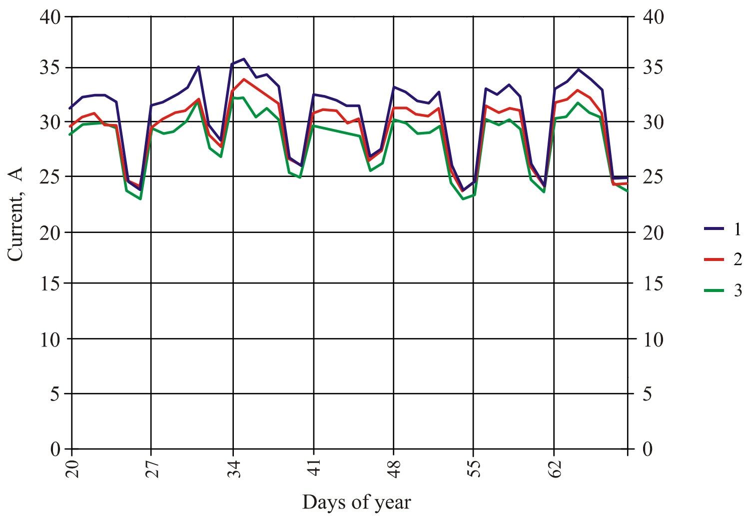

Figure 6.22. Actual (1) and estimated (2) value of current I42, and actual and estimated value (3) of current I33, daily values

In this thesis the operation of the example network is treated only in the distribution network normal scheme conditions. However, possible digressions from the normal scheme are observed by the estimation algorithm. In case of special schemes, which are due to maintenance or faults, the algorithm does not deliver any results. In Fig. 6.23 the data on weeks 31 and 32 is missing because the network operation is not in correspondence with the normal scheme. The indication of displacements is here the currents and powers at line L-45, which, in condition of normal scheme, should be disconnected. The operation of the estimation algorithm is automatically continued when the normal scheme is recovered.

According to the above presented examples there is no doubt of the fact that the *SCADA*-data of the distribution network operation should be and is possible to be estimated. The previously described estimation algorithm solves almost all problems related to the erroneousness of operation measurement data. Nevertheless, situations where the final answer can not be obtained algorithmically are also possible. Those situations should be retrospectively solved by corresponding persons (load manager etc.). However, it is essential that the estimation algorithm informs the employees about those situations.

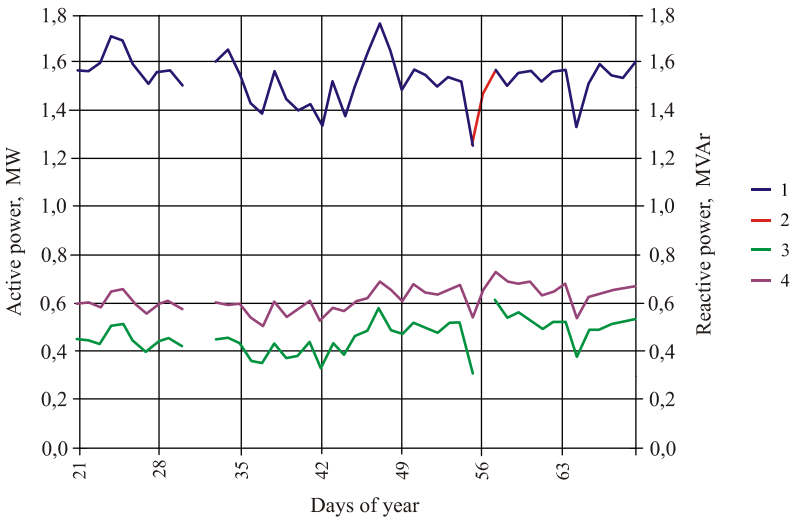

Figure 6.23. Actual (1) and estimated (2) values of active power P44, and actual (3) and estimated (4) values of reactive power Q44, daily values

The estimation methodology may principally be diversely improved. It is possible to apply the methodology described in Chapters 5.3.1 and 5.3.2 to the full extent. It is feasible to specify the transformer ratios and settings of the reactive power sources. Load voltage sensitivity, especially in the case of reactive loads, should be considered. However, the above mentioned measures enable only to adjust the estimation results. Important changes of the operation may be checked on the ground of previously described manner.

The estimation period for operation analysis is of course optional (in the example network up to six years). During the dispatching of the distribution network the estimation may be performed for every time interval (hour or a part of it) when the measurement data arrives. Depending on the purpose the estimation can be executed at different times, e.g. once a day. At the same time the forecast of loads and other state variables for the desired time period (some days) are also obtained. The load forecast forms the same expected value of load as was in the case of estimation. There are no formal limits of forecast lead time. Due to the absence of actual load data on the anticipation period, the expected deviation PC will decrease to zero after 7…10 days. For the calculation of the influence of the temperature PI the meteorologically forecasted temperature is used. If the forecast data is missing then also the temperature influence will decrease to zero and then the load forecast is represented only by mathematical expectation PE.

CONCLUSIONS AND FUTURE WORK

Monitoring of the distribution network operation depends on the available information from the network offered by the information systems. Based on adequate and sufficient information it is possible to derive accurate decisions to control and plan the distribution network and its operation. From customers' point of view this means more enhanced reliability and security of supply. Quality of supply is directly influenced by the network operation and applied technologies.

The advancements in distribution network control technologies over the years have been remarkable. More sophisticated *SCADA* systems have been developed and the number of remotely controlled substations and switching points is increasing. Nowadays, it is even possible to use tele-control at the distribution substations through, which the customers are directly supplied. It is possible to perform and coordinate voltage regulation with transformers and capacitor banks through appropriate algorithms, considering the seasonal and daily variations and regularities.

The use of computers has significantly extended the possibilities to control the network operation. For example, in case of disturbance, it is possible to locate the fault remotely, disconnect it from the network and restore the supply to all customers. Through the information systems it is possible to observe if the network operation is within allowable limits or not. However, even more possibilities are available if adequate control software and different monitoring algorithms are composed and used. In this thesis a new methodology for monitoring of the distribution network operation is presented.

Network operation is substantially determined by the load. Therefore, the efficiency of handling the operation is first of all dependent on the adequacy of modelling the load. In this thesis a mathematical model, which describes the regular changes of loads (daily, weekly and yearly periodicity and trend), stochasticity and dependency on temperature and state variables (voltage, frequency), is used. Such model is significantly more effective compared to the traditional load forecasting methods. The forecasting methods are practically data models and can be used only for solving trivial problems, for example, to find the short-term forecast of the load and even then enough reliable load data should be available. However, in the distribution networks, where the load data is rather stochastic and sometimes is even completely missing, it can be stated that the forecasting models are unusable here.

Based on the mathematical model of load, it is possible to compose effective algorithms, which are used for monitoring of the distribution network operation. Those algorithms consist of analysis, forecasting and estimation of the operation. Calculation of network operation for the past or for the future could be based on different initial conditions. In the operation analysis the actual loads, values of which are checked and which are, in case of absence, substituted with truthful values, may be used. To find the operation, which corresponds to the normal outdoor temperature or to the given temperature, it is possible to normalize or simulate the load values in relation to temperature. Therefore, the load values and accordingly the network operation can be forecasted both for short and long time periods. In the long-term forecast the temperature is simulated. The state estimation procedure is especially important, because the available measurement data for the operation often consists of significant errors and can be totally misleading or is even completely missing. In this thesis an algorithm for the distribution network estimation is presented and it is showed that it is necessary and possible to estimate the *SCADA*-data of operation.

Certainly, the problems related to the monitoring of the distribution network operation are not exhausted with this work. Although no direct deficiencies of the mathematical model of load, which is used as a base for operation monitoring, were not noticed, further developments can be foreseen. It is necessary to draw the attention to the mutual dependency of load cases, e.g. load scenarios. The changes in the network scheme can cause simultaneous change of several bus loads, which must be considered for representing the network operation adequately. The correlation between the loads should be considered. Besides, describing random changes of the operation veraciously, correlation influences significantly short-term forecasts of load and, consequently, the whole network operation.

The essential research topic is the modelling of unobservable network loads. The problem here is the availability of necessary data for estimation of the model parameters. Principally, the structure of the model does not depend on the data available for the observable loads. In every case, all the model parameters are estimated and in applications, all load models are equivalent. However, the accuracy of the model depends on the amount and quality of available initial data. Nowadays, the problem is not so much with the deficiency of measurement data but with the maladjustment of available information systems. Hence, a lot of data on operatively unobservable distribution network is available in commercial energy metering systems. Unfortunately, the availability of those data for the purpose of modelling the loads for network operation monitoring, is complicated.

The practical implementation of the electrical network monitoring methodology depends on the purpose. One possible task is to reinforce the distribution network to guarantee the quality of power to all customers. Necessary investments here extend to billons of Estonian crowns. Up to the present the decisions to reinforce the network have been made based on customer complaints. However, it is necessary to perform systematic network calculations, which would allow to make the investments more objectively. The operatively unobservable network is mainly under consideration here and the modelling of loads is therefore complicated.

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3. **Kilter, J.**, Meldorf, M. Comprehensive Analysis of Electrical Distribution Network Operation – An Approach of Electrical Load Modelling. *WSEAS Transactions on Power Systems*. Issue 12, Volume 3, December 2008, pp. 725-734.
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5. Meldorf, M., Täht, T., **Kilter, J.** Stochasticity of Electrical Network Load. *Oil Shale*, 2007, v.24 n.2S, 225-235 pp.
6. Meldorf, M., Treufeldt, Ü., **Kilter, J.** Temperature Dependency of Electrical Network Load. *Oil Shale*, 2007, v.24 n.2S, 236-248 pp.
7. Meldorf, M., **Kilter, J.**, Pajo, R. Comprehensive Modelling of Load. Proc. of *CIGRE NRCC Regional Meeting*, Tallinn, 18-20 June, pp. 145-150.
8. **Kilter, J.**, Meldorf, M. Modelling and Estimation of Distribution Network Operation. Proc. of *RTU Scientific Conference*, 2007, Riga, 11-13 October, pp. 103-108.
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12. Meldorf, M., Treufeldt, Ü., **Kilter, J.** Estimation of Distribution Network State on the basis of a Mathematical Load Model. *Oil Shale*, 2005, Vol.22, No.2 Special, pp. 161 – 170.
13. **Kilter, J.** Online Monitoring of the Distribution Network Operation. Master thesis, Tallinn University of Technology, 2005, 133 pp.
14. **Kilter, J.** Load Cases in Estonian Transmission System. Bachelor Thesis, Tallinn University of Technology, 2003, 92 pp.

ABSTRACT

Monitoring of the Electrical Distribution Network Operation

Power system consists of different parts: generation, transmission, distribution and demand of electricity. The purpose of the distribution network is to distribute electrical energy from transmission substations to consumers taken into account economical efficiency and other criteria. To guarantee the optimal operation of the distribution network, adequate system modelling, calculation and analysis for short- and long-term period is required. The objective of modelling and analysis is to obtain more efficient operation of the distribution network and enhance network reliability and quality of power. In distribution networks the availability of initial data for analysis is compared to the data, obtained from transmission networks, modest or sometimes even missing. The nature of distribution network is more irregular and stochastic. Therefore, comprehensive methods and algorithms for distribution network analysis are required.

In this thesis methodology for monitoring of distribution network operation is proposed. Monitoring consists of network representation, gathering information, estimation of the load model, network operation modelling and estimation, verification of results and models. The methodology is based on the mathematical model of load, which describes the regular changes of loads (daily, weekly and yearly periodicity and trend), stochasticity and dependency on outdoor temperature and state variables (voltage, frequency). The load model is used the basis for distribution network monitoring. The employed mathematical model is significantly more effective compared to the traditional load forecasting methods.

Based on the mathematical model of load, it is possible to compose effective algorithms, which are used for the monitoring of the distribution network operation. The network operation is determined, based on different conditions and contingencies and their influence on available network configuration. Especially important is the state estimation procedure, because the available measurement data for the operation often consists of significant errors and can be totally misleading. In this thesis an algorithm for the distribution network estimation is presented and it is showed that it is necessary and possible to estimate the *SCADA*-data of operation.

For practical application of the mathematical model of the load for monitoring distribution network operation, adequate computer programs must exist. In this research the program package *Elmo* (*Electrical Load Monitoring*) is used. The monitoring methodology is applied to one part of Estonian 35 kV distribution network. Data for the period of six years was collected and used. Research related to the handling of the loads is performed by the program *ElmoSet*. In addition, an application program *ElmoDisco*, which performs the necessary calculations of the electrical network, including the state estimation, is used. During the practical implementation of the methodology, estimation of network load, calculation and estimation of distribution network operation were performed and results presented.

KOKKUVÕTE

Jaotusvõrgu talitluse seire

Elektrisüsteem koosneb erinevatest osadest: generaatoritest, ülekandevõrgust, jaotusvõrgust ja tarbijatest. Jaotusvõrkude talitlemise eesmärgiks on kanda üle elektrienergiat suurtest ülekandevõrgu alajaamadest tarbijateni kasutades erinevaid pingeastmeid ning arvestades majanduslikke ja muid talitlust mõjutavaid tingimusi. Tagamaks jaotusvõrgu optimaalse talitlust nii lühemas kui pikemas perspektiivis on võrgu talitlust vaja adekvaatselt modelleerida, arvutada ja analüüsida. Eesmärgiks on tagada jaotusvõrgu efektiivne talitlemine ning vajalik töökindlus ja elektrienergia kvaliteet. Ülekandevõrkudega võrreldes on analüüsiks tarvilik andmete maht jaotusvõrkudes tagasihoidlik või puudub mõnikord sootuks. Lisaks on jaotusvõrgu koormused oma iseloomult ebaregulaarsed ja juhuslikud. Sellest tulenevalt on jaotusvõrkude talitluse seireks vaja koostada sobilikke meetodeid ja algoritme.

Käesolevas doktoritöös esitatakse jaotusvõrgu talitluse seire metodoloogia, mis käsitleb võrgu kujutamist, informatsiooni hankimist, koormusmudeli estimeerimist, võrgu talitluse modelleerimist ja estimeerimist ning mudelite ja tulemuste verifitseerimist. Metodoloogia põhineb koormuse matemaatilisel mudelil, mis kirjeldab koormuse regulaarseid muutusi (päevane, nädalane ja sesoonne perioodilisus ja trend), juhuslikkust ja sõltuvust temperatuurist ja olekumuutujatest (pinge, sagedus). Koormusmudel on talitluse seire aluseks. Rakendatud koormusmudel on võrreldes tavapäraste koormuse prognoosimudelitega tunduvalt efektiivsem võimaldades mitmekülgselt modelleerida, hinnata ning analüüsida koormust.

Tuginedes koormuse matemaatilisele mudelile on võimalik koostada efektiivseid algoritme talitluse seireks, mis seisneb talitluse analüüsimises, prognoosimises ja imiteerimises. Võrgu talitlus on suures ulatuses allutatud erinevatele kitsendusele ning võrgu konfiguratsiooni muutustele. Oluline on talitluse estimeerimine, sest talitluse kohta saadav informatsioon sisaldab tihti vigasid, on eksitav või puudub mõnikord üldse. Käesolevas doktoritöös on esitatud jaotusvõrgu talitluse estimeerimise algoritm ning näidatud, et *SCADA* vahendusel hangitud talitluse andmete estimeerimine on tarvilik ja võimalik.

Koormuse matemaatilise mudeli praktiliseks rakendamiseks jaotusvõrgu talitluse seirel on vaja vastavaid arvutiprogramme. Käesolevas uurimustöös on kasutatud programmipakett *Elmo* (*Electrical Load Monitoring*). Esitatud seiremetodoloogiat on praktiliselt rakendatud ühe Eesti 35 kV jaotusvõrgu piirkonna andmetel. Selle võrgu kohta on kogutud ja kasutatud kuue aasta andmeid. Uurimustöös kasutati programme *ElmoSet* ja *ElmoDisco*, mis võimaldavad estimeerida koormust ning teha jaotusvõrgu talitluse arvutusi ja estimeerimist. Saadud tulemusi on töös kirjeldatud ja analüüsitud.

ELULOOKIRJELDUS

1. Isikuandmed
   Ees- ja perekonnanimi: Jako Kilter
   Sünniaeg ja -koht: 02.01.1981, Tallinn
   Kodakondsus: Eesti

2. Kontaktandmed
   Aadress: Pargi tee 7, Peetri küla, Rae vald
   Telefon: +372 56 984 766
   E-posti aadress: jako.kilter@ttu.ee

3. Hariduskäik

Õppeasutus (nimetus lõpetamise ajal)	Lõpetamise aeg	Haridus (eriala/kraad)
Tallinna Tehnikaülikool	2005	elektroenergeetika eriala, tehnikateaduste magister
Tallinna Tehnikaülikool	2003	elektroenergeetika eriala, tehnikateaduste bakalaureus
Tallinna Lasnamäe Üldgümnaasium	1999	keskharidus

4. Keelteoskus (alg-, kesk- või kõrgtase)

Keel	Tase
Eesti	kõrgtase
Inglise	kõrgtase
Soome	kesktase
Vene	kesktase

5. Täiendusõpe

Õppimise aeg	Täiendusõppe läbiviija nimetus
2008	Usesoft AS, Eesti
2008	LK Technical Pty Ltd, Austraalia
2008	University of Wollongong, Austraalia
2008	CIGRE Russia and NIIPT, Venemaa
2008	Fachhochschule Stralsund, Saksamaa

2008	Helsinki University of Technology, Soome
2007	Solvina, Rootsi
2006-2007	University of Manchester, Inglismaa
2003	Gotland University College, Rootsi
2002	Fachhochschule Stralsund, Saksamaa

6. Teenistuskäik

Töötamise aeg	Tööandja nimetus	Ametikoht
2007 – …	OÜ Põhivõrk	tehnilise kvaliteedi spetsialist
2006 – …	Tallinna Tehnikaülikool	assistent
2006 – 2007	OÜ Põhivõrk	püsitalitluse planeerija
2005 – 2006	Tallinna Tehnikaülikool	laborant
2003 – 2006	OÜ Jaotusvõrk	vanemdispetšer
2002 – 2003	EE AS Jaotusvõrk	dispetšer

7. Teadustegevus

- Leping LEP8033 „Uue ametkondliku standardi versiooni – Tehnilised nõuded elektrituulikute liitumiseks elektrivõrguga – projekt", 2008, põhitäitja.
- Sihtfinantseeritav teema T512 "Töökindel ja säästlik energeetika", Tallinna Tehnikaülikool, Elektroenergeetika instituut, 2003-2007, täitja.
- ETF grant G5629 "Elektrivõrgu koormuse jaotusseaduse estimeerimine". Tallinna Tehnikaülikool, Elektroenergeetika instituut, 2003-2005, täitja.
- Teadustöö 261L teine etapp "Eesti põhivõrgu koormuste analüüs II". Tallinna Tehnikaülikool, Elektroenergeetika instituut, 2003. Tellija OÜ Põhivõrk, täitja.

Teadustegevuse viimase 5 aasta olulisemad tulemused on esitatud järgmistes publikatsioonides:

- **Kilter, J.**, Reinson, A. Integration of wide area monitoring technology and enhancement of power system reliability in Baltic Power System. *Proceedings of the IEEE 6th International Conference on Power Quality and Supply Reliability*, 27-29 August 2008, Pärnu, Estonia, pp. 41-46.
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- Meldorf, M., Treufeldt, Ü., **Kilter, J.** State Estimation Technique for Distribution Networks. *IEEE Conference Proceedings, PowerTech'05*. St. Petersburg. June 2005. [CD-ROM], paper no. 374.
- Meldorf, M., Treufeldt, Ü., **Kilter, J.** Estimation of Distribution Network State on the basis of a Mathematical Load Model. *Oil Shale*, 2005, Vol.22, No.2 Special, pp. 161 – 170.

8. Kaitstud lõputööd

- Magistritöö: "Jaotusvõrgu talitluse sidusseire", 2005
juhendaja prof. Mati Meldorf
- Bakalaureusetöö: "Eesti Energia põhivõrgu koormusjuhtumid", 2003
juhendaja prof. Mati Meldorf

9. Teadustöö põhisuunad

Teadustöö põhisuunad on elektrivõrkude talitluse estimeerimine ja analüüs ning meetodid, elektrisüsteemi talitluse jälgimine ja juhtimine, koormuste modelleerimine ja analüüs, elektrisüsteemi stabiilsus ja pinge kvaliteet, tuuleparkide ühendamine elektrivõrguga ja tekkivate probleemide analüüs.

CURRICULUM VITAE

1. Personal data

    Name: Jako Kilter
    Date and place of birth: 02.01.1981, Tallinn
    Nationality: Estonian

2. Contact information

    Address: Pargi road 7, Peetri village, Rae parish
    Phone: +372 56 984 766
    E-mail: jako.kilter@ttu.ee

3. Education

Educational institution	Graduation year	Education (field of study/degree)
Tallinn University of Technology	2005	electrical power engineering, master of science
Tallinn University of Technology	2003	electrical power engineering, bachelor of science
Tallinn Lasnamäe High School	1999	secondary education

4. Language competence/skills (fluent; average, basic skills)

Language	Level
Estonian	fluent
English	fluent
Finnish	average
Russian	average

5. Special Courses

Period	Educational or other organisation
2008	Usesoft AS, Estonia
2008	LK Technical Pty Ltd, Australia
2008	University of Wollongong, Australia
2008	CIGRE Russia and NIIPT, Russia

2008	Fachhochschule Stralsund, Germany
2008	Helsinki University of Technology, Finland
2007	Solvina, Sweden
2006-2007	University of Manchester, United Kingdom
2003	Gotland University College, Sweden
2002	Fachhochschule Stralsund, Germany

6. Professional Employment

Period	Organisation	Position
2007 – …	OÜ Põhivõrk	technical quality specialist
2006 – …	Tallinn University of Technology	teaching assistant
2006 – 2007	OÜ Põhivõrk	steady-state planner
2005 – 2006	Tallinn University of Technology	laboratory assistant
2003 – 2006	OÜ Jaotusvõrk	senior dispatcher
2002 – 2003	EE AS Jaotusvõrk	dispatcher

7. Scientific work

- Contract LEP8033 „New version of company standard – Technical requirements for connection of wind parks to the network – project", 2008.
- Target financed research topic T512 "Reliable and economical electrical engineering", Tallinn University of Technology, Department of Electrical Power Engineering, 2003-2007.
- ETF grant G5629 "Estimation of the distribution of electrical network load". Tallinn University of Technology, Department of Electrical Power Engineering, 2003-2005.
- Scientific work 261L second stage "Analysis of Estonian transmission network load II". Tallinn University of Technology, Department of Electrical Power Engineering, 2003.

The results of the scientific work for last 5 years have been published in:

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8. Defended theses

- Master Thesis: "Online monitoring of the Distribution Network Operation", 2005, supervisor prof. Mati Meldorf
- Bachelor Thesis: "Load cases in Estonian transmission network", 2003, supervisor prof. Mati Meldorf

9. Main areas of scientific work/Current research topics

Main areas of research include electrical network state estimation, analysis and methods, power system monitoring and control, modelling and analysis of loads, power system stability and power quality, integration of wind parks into power system.