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EDISON – research programme on electric distribution automation 1993–1997

Final report 1997

VTT

TECHNICAL RESEARCH CENTRE OF FINLAND
ESPOO 1998

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Final report 1997

Edited by

Matti Lehtonen

VTT Energy

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FINNISH ENERGY TECHNOLOGY PROGRAMMES

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ABSTRACT

This report comprises a summary of the results of the five year research programme EDISON on distribution automation in Finnish utilities. The research programme (1993 - 1997) was conducted under the leadership of VTT Energy, in cooperation with universities, distribution companies and the manufacturing industry. The main part of the funding has been from the Technology Development Centre TEKES and from manufacturing companies.

The goal of the research programme was to develop a new scheme for a complete distribution automation system, including the network automation, computer systems in the control centre and the customer associated automation functions. In addition, the techniques for demand side management were developed and integrated into the automation scheme.

The final aim was to demonstrate the automation functions and systems of the scheme in real distribution systems. The results of nineteen projects are given in this report.

LIST OF PROJECTS PRESENTED IN THE REPORT

The projects presented in this report, and their responsible researchers are as follows:

- Automatic location of short circuit faults. Matti Lehtonen, VTT Energy, Erkki Antila, ABB Transmit Oy, Matti Seppänen, North-Carelian Power Company.
- Characteristics of earth faults in power systems with a compensated or an unearthed neutral. Seppo Hänninen, VTT Energy.
- The effect of earth fault protection practices on the frequency of outages in MV lines. Erkki Lakervi and Ari Nikander, Tampere University of Technology
- The event analysis in primary substation. Harri Paulasaari, Tampere University of Technology.
- A distribution management system. Pekka Verho, Pertti järventausta and Matti Kärenlampi Tampere University of Technology, Jarmo Partanen, Lappeenranta University of Technology.
- Additional functions of remotely read kWh-meters. Pekka Koponen, VTT Energy, Seppo Vehviläinen, Mittrix Oy and Juha Rantanen, Helsinki Energy.
- Wireless communication technologies in distribution automation. Juha Takala, VTT Energy.
- A scheme for a future distribution automation system in Finnish utilities. Matti Lehtonen, VTT Energy.
- Distribution load estimation - DLE. Anssi Seppälä, VTT Energy.
- Distribution energy management systems in the environment of de-regulated electricity market. Matti Lehtonen, Anssi Seppälä, Veikko Kekkonen and Göran Koreneff, VTT Energy.
- Development of planning methods for demand side management. Seppo Kärkkäinen, Veikko Kekkonen, VTT Energy, Pekka Rissanen, Tietosavo Oy.
- Communication technologies for DSM & EurUCA, european utility communication architecture. Pentti Uuspää, VTT Energy.
- Optimization of load control. Pekka Koponen, VTT Energy
- Electricity spot price forecasting. Erkki Laitinen, Janne Lilleborg, Vaasa University

- A method for electricity spot price short term forecasting in de-regulated power market. Erkki Laitinen, University of Vaasa.

- Development of automatic fault isolation and supply restoration. Matti Lehtonen, VTT Energy.

- A system for the indication of earth faults with high fault resistances. Seppo Hänninen, VTT Energy

- Locating earth faults by the aid of neutral voltage analysis. Erkki Lakervi, Helsinki University of Technology and Ari Nikander, Tampere University of Technology.

FOREWORD

This report comprises a short summary of the main results of the research programme EDISON during its five years 1993-1997. Altogether nineteen projects are presented. This work has been carried out in cooperation with VTT Energy, universities, distribution companies and the manufacturing industry.

The main part of funding of the research programme EDISON is from the Technology Development Centre (Tekes), ABB Transmit Oy and from the Electric Power Pool. In addition, many distribution utilities and manufacturing companies have made a strong contribution.

The research programme has been supervised by a board, the chairman of which is Mr. Esa Pekkola of ABB Corporate Research, Vaasa. The other members have been:

Dir. Otso Kuusisto, Finnish Electricity Association
Prof. Erkki Lakervi, Helsinki University of Technology
Dir. Tauno Leppämäki, North-Carelian Power Company
Mr. Touko Salo, Enermet Oy
Mr. Kari Komulainen, Tekes
Dr. Seppo Kärkkäinen, VTT Energy

The head of the research programme EDISON has been Dr. Matti Lehtonen, VTT Energy.

Espoo, Otaniemi
December 1997

VTT Energy
Energy Systems

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1 INTRODUCTION

The research programme EDISON, on distribution automation, was launched in 1993 with the support of the Ministry of Trade and Industry (KTM). In the beginning of 1995, the supervision and main support of the programme was shifted by KTM to the Technology Development Centre TEKES.

The goal of the five year programme was to develop, for the Finnish power companies, a new distribution automation system including the network automation, the computer systems in the control center and the functions for load and demand side management.

The distribution automation system was implemented using the latest data transmission and data processing technology. The aim was that the complete system will be demonstrated at the end of the programme, in the year 1997. In the course of the programme, new devices, systems and software packages were developed. The work proceeded step by step in cooperation with universities, the manufacturing industry and power companies. The practical work comprised:

- an analysis of distribution systems and end use practices, as well the different functions associated with them
- the development of a scheme for the complete distribution automation (DA) system
- the development of methods, software packages and equipment, based on the requirements of the DA scheme
- demonstration of the functions and equipment associated with the DA scheme

This report is a summary of the main results of the programme during its five active years. Results of altogether nineteen projects are given.

2 AUTOMATIC LOCATION OF SHORT CIRCUIT FAULTS

Matti Lehtonen, VTT Energy, Tapio Hakola ABB Power Oy, Erkki Antila, ABB Power Oy and Matti Seppänen, North-Carelian Power Company

In this chapter, the automatic location of short circuit faults on medium voltage distribution lines, based on the integration of computer systems of medium voltage distribution network automation is discussed. First the distribution data management systems and their interface with the substation telecontrol, or SCADA systems, is studied. Then the integration of substation telecontrol system and computerized relay protection is discussed. Finally, the implementation of the fault location system is presented and the practical experience with the system is discussed.

2.1 DISTRIBUTION DATA MANAGEMENT SYSTEMS

The heart of a modern distribution automation system (DAS) is the distribution data management system (DMS) which integrates the substation telecontrol system to all the other important information systems needed for medium voltage network automation. The modern DMS systems support functions such as:

- network planning
- supervision and operation management
- maintenance
- network calculations
- network simulations
- fault diagnosis and event recording
- statistics and reporting
- map drawing and diagram production

The DMS system can also be used for real-time presentation of the network connections. Consequently, the large paper diagrams needed before, for network topology monitoring, can be replaced by computer displays. Here the switching state of the. network can be represented by different colors, either according to the substation transformers, or medium voltage feeders of MV/LV transformer circuits.

Since the network drawings are based on the geographical co-ordinates, the electrical diagrams can be combined with street maps. This is very helpful when clearing faults and restoring the networks after a disturbance. The database system also makes it easy to check short circuit currents and the load carrying capacity of the distribution network. This is particularly useful in abnormal situations when network operational personnel have to make quick decisions /15/.

The DMS system also enables more accurate load monitoring. Consequently, the security margin between the rated capacity of power system components and the actual loads can be smaller. This is economically attractive because it reduces the necessary investment in the distribution network. To gain these benefits, a powerful model for distribution load estimation must be available. This can be provided by combining the statistical data, i.e. typical user load variation curves with the back ground data of the electricity users and to the on-line measurements of the power flows in various locations of the distribution network /43/.

The integration of the DMS and substation telecontrol systems is illustrated in Figure 1. Data exchange works two way as interactive communication. However, the main data exchange is from the telecontrol system to the DMS. The interface, which is controlled by the telecontrol system, is based on events with data vectors. The information transferred includes /28/:

- spontaneously the changes of the switch positions, data on the operation of the substation transformer on-load tap-changer and information on protective relay operations. The time delay for updating to the DMS system is 2 to 3 seconds

- spontaneously the values of analog measurements in the case that their changes have exceeded the dead band (load flows of substation transformers, busbar voltages, feeder currents, weather measurements like wind velocity and direction, air humidity, outdoor temperature).

- the 15 minute average values of analog measurements

- the 1 hour average values of analog measurements

The data transfer program can also update the files of the DMS system after an interruption has occurred in the communication interface. In the case of short interruptions this is made possible by a buffer file in the telecontrol system. In order to be able to recover after major outages, another back up function was developed. This is able to compare and update all the pieces of data in the target files of DMS.

In addition to the link shown in Figure 1, there is a connection between the DMS system and the customer data base system. This interface is a simple file transfer, operated on a batch basis. The data transferred includes, for each customer, the customer type (one of, at maximum, 46 customer classes), the estimated or metered annual energy and the customers location in the network. These data are needed when constructing the load models for the distribution load estimation function.

2.2 SUBSTATION SCADA AND INTEGRATED RELAY PROTECTION

In conventional systems, the substation telecontrol system has been centralized and the data processing capacity of the substation remote terminal units (RTU's) has been very limited. Today, the microprocessor based protective relays offer possibilities for a distributed system and for a substantial increase in computing capacity at the substation.

An example of local substation automation with an integrated telecontrol and relay protection system is given in Figure 2. The central node in the integrated system is the control data communicator (CDC), which works as a bridge between the telecontrol system at the control center level and the local automation / protection units in the substation bay level. The data transmission polls in two levels as follows:

- control center - CDC
- CDC - bay level

The system is asynchronous, so that the transmitted data is temporarily stored in two buffers of the CDC. One of the buffers is for measurement data and the other for event data, such as alarms and indications of relay operations. The latter buffer has higher priority in data transmission. In addition, the control commands and their responses always have higher priority than the measurement data.

The data transmission of the two polling cycles is in both cases based on the ANSI X3.28 protocol. The higher level (control center - CDC) is implemented according to the ISO/OSI seven layer model. The local data transmission is based on a fibre optic bus. The benefit of this solution is, in addition to high data rates, the immunity to the electromagnetic interference. The fibre optic bus is partly looped and partly radial, in order to gain high enough reliability at a comparatively low price.

The data transmitted from the CDC to the control center level includes all the information processed in conventional telecontrol systems. In addition some newer applications are possible. Among these are the remote setting of relay parameters and remote monitoring of circuit breaker operation times and service limits. The protective relays also register the fault currents, which opens possibilities for computational fault location.

The bay level functions include relay protection, autoreclosure automatics, remote reading of status and measurement data and the control of circuit breakers and other possible objects. These functions can be implemented with an integrated protection and control terminal, the block diagram of which is shown in Figure 3 /2, 3/.

In addition, in the integrated protection and substation control system, there is an alarm center or an annunciator (Figure 2). The task of this is to provide a local indication of the selected alarms and control responses. In this module, some analog measurements can also be displayed, like the transformer temperatures, weather measurements, feeder currents or busbar voltages.

2.3 AN INTEGRATED FAULT LOCATION SYSTEM

In this section, the practical implementation of the fault location, based on the integration of relay protection, substation telecontrol system and the data management system is presented. The system is based on the comparison of the measured and the computed fault currents. The computation is made on-line, assuming the same network topology as it was when the fault occurred. As a result, the estimated distance of the fault from the substation is obtained. This distance is then, in turn, compared to the network diagram, and the possible fault locations are shown on a graphical display of the distribution network. Here the network presentation is based on geographical coordinates, which makes it possible to combine it with street and terrain maps (Figure 4).

When a fault happens, the operation of the automation system is as follows:

1) the protective relays store the fault information (currents, fault type, phases involved, feeder involved, information on reclosing steps)

2) in the next polling cycle of the CDC, the event buffer is updated with a corresponding piece of alarm data

3) in the next polling cycle of the substation SCADA central unit, the alarm is transmitted to the control centre

4) after analyzing the alarm, the central unit sends a request for fault information to the CDC, and consequently to the protection / control unit

5) as a response to the request, the protection / control unit sends the recorded information to the CDC, which further transmits it to the telecontrol system central unit

6) the telecontrol system adds some more information to the received fault data. This information includes the measured load current of the feeder concerned and the active and reactive load flows for the substation main transformer before the fault occurred

7) the information is transferred as spontaneous vector messages to the data management system operating in a DEC-station (Unix). The DMS system is connected to the telecontrol system via an Ethernet bus

8) the DMS computes the corresponding fault currents of the feeder concerned and compares the measured data to the computation results. Before the comparison, the load currents, superposed on the measured currents during the fault, are compensated for.

All the data needed for fault location computation is stored in the virtual memory of the DMS system. The purpose of this arrangement is to make the processing fast enough to meet the practical requirements.

The accuracy of the short circuit fault distance estimation is governed by two main error sources: The load current superposed on the measured fault current and the fault resistance /26/. The problem with the superposed load current is, that its magnitude is changed dynamically with the voltage change during the fault. For the load behavior, theoretical models have been developed, which can be used for load current compensation. Essential for the performance of the models is accurate data on the load currents just before the fault and information on the model parameters. The load currents are obtained from the files of the substation telecontrol system, whereas the parameters must be selected according to practical experience.

Another problem is, that in the systems based on current measurement solely, no information is available on the fault resistance magnitude. Hence, the distance computation must be made with an assumption of zero fault resistance. This gives the estimated maximum fault distance. Because of the fault resistance, the actual fault must be closer than the computed distance.

This kind of automatic fault location system is in active use in the North-Carelian Power Company. According to the practical experience in rural overhead line networks, the average error in fault distance estimation of the above system is 1.2 km. For comparison, the corresponding average fault distance was 13 km. For close faults the absolute errors are smaller, whereas for distant faults they are larger, respectively. This degree of performance is good enough for defining the faulty line section between two isolating disconnectors. If there are several branches or laterals in the line concerned, several possible fault locations are also obtained. Among these the actual fault point must be distinguished by some other means. One possible solution is the remotely monitored fault current indicators in the line branching nodes.

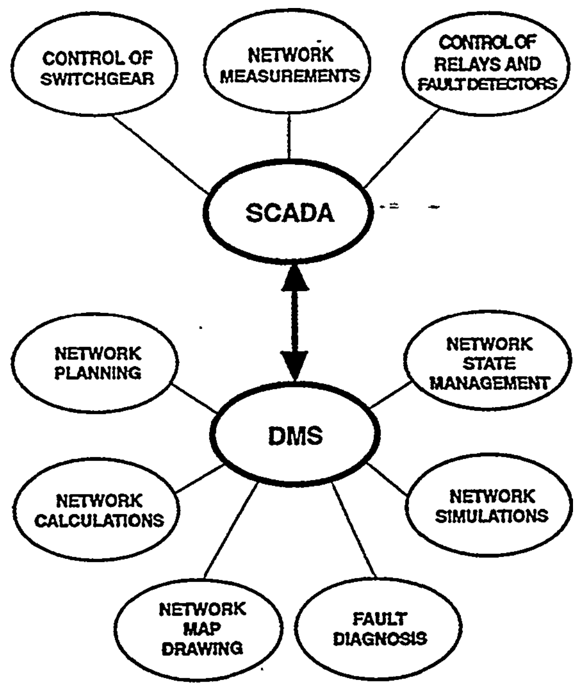

Fig. 1. The integration of a substation telecontrol (SCADA) and a distribution data management system (DMS).

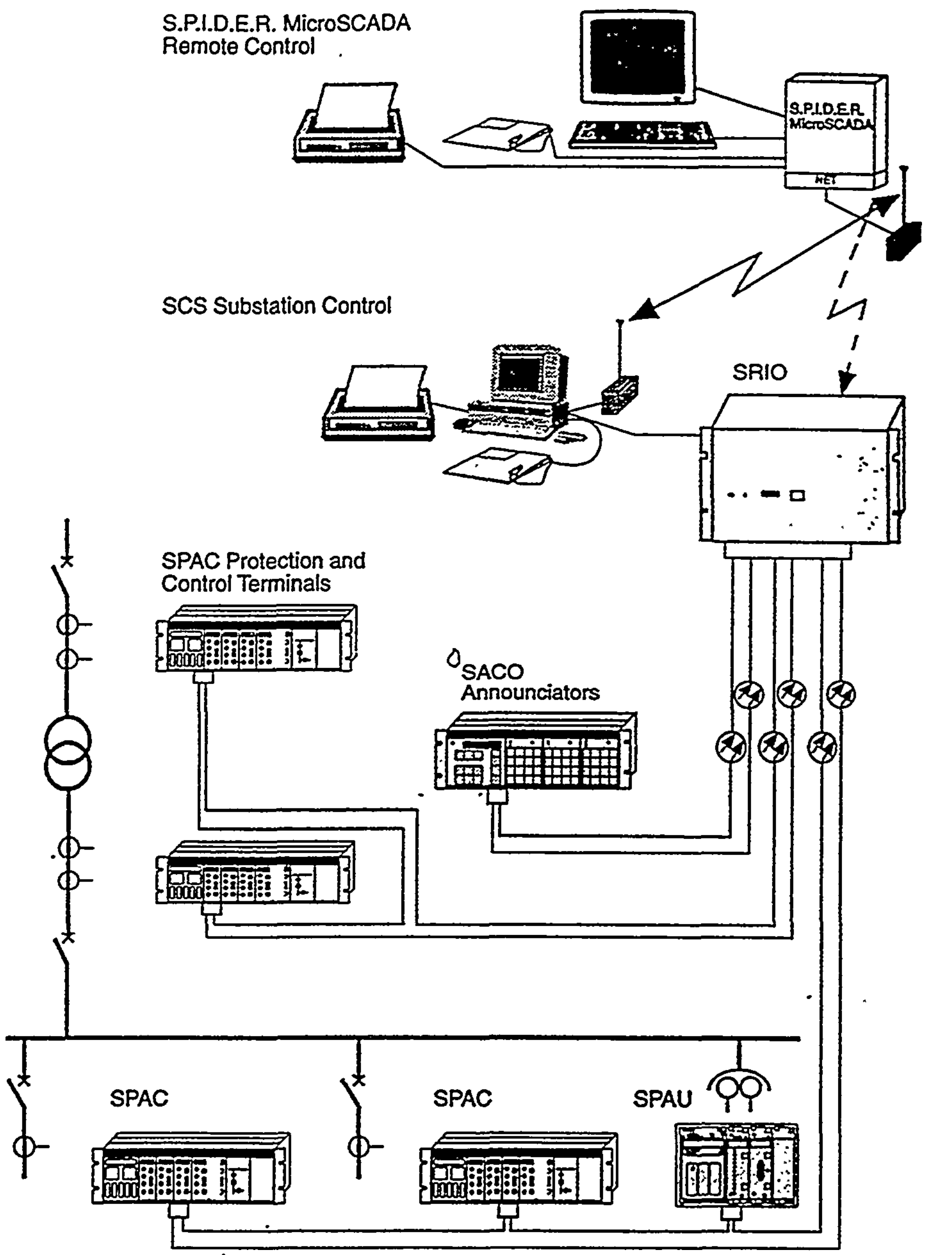

Fig. 2. An example of substation automation based on an integrated telecontrol (SCADA) and relay protection system. SRIO is the control data communicator, SCS is the substation control system, SPAC is an integrated control and protection terminal, SPAU is a voltage relay module and SACO is an alarm unit.

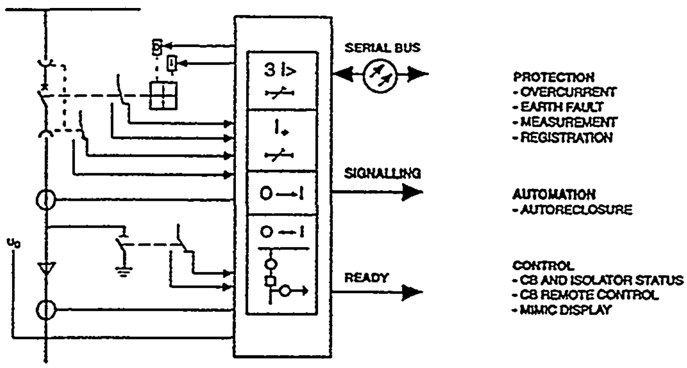

Fig. 3. A feeder bay with an integrated protection and control unit.

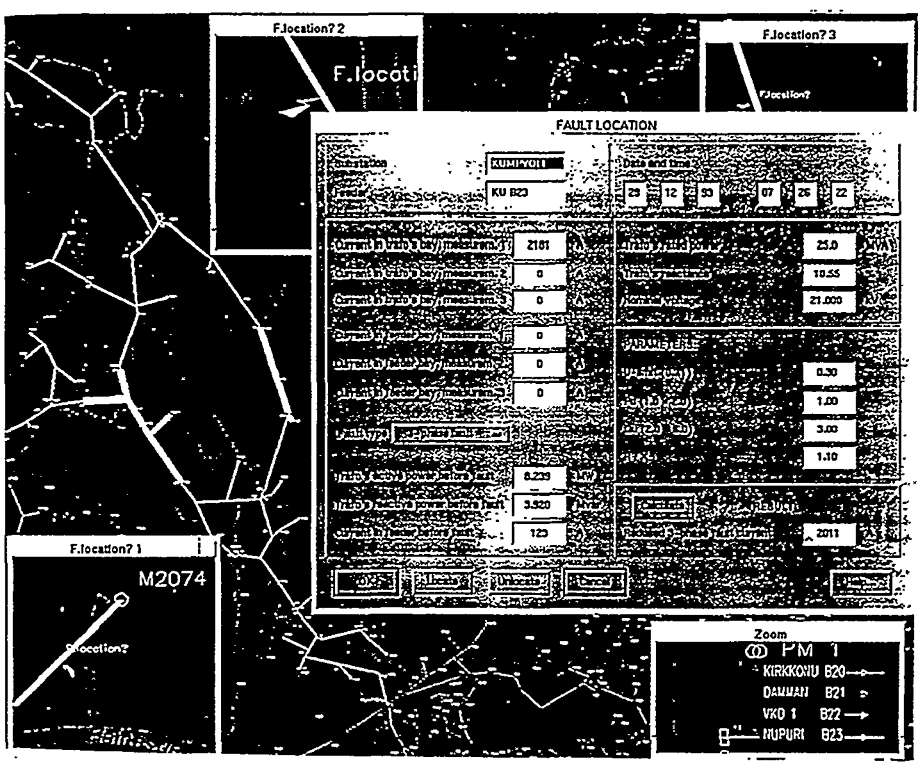

Fig. 4. An example of the graphical display of the automatic fault location system. The possible faulty line sections are shown using a bold line. The most likely fault location within the section is shown using the symbol of lightning.

3 CHARACTERISTICS OF EARTH FAULTS IN POWER SYSTEMS WITH A COMPENSATED OR AN UNEARTHED NEUTRAL

Seppo Hänninen and Matti Lehtonen VTT Energy, Tapio Hakola and Erkki Antila, ABB Transmit Oy, Jarmo Ström, Espoo Electricity Co and Stefan Ingman, Vaasa Electricity Co

3.1 INTRODUCTION

The most common fault type in the electrical distribution networks is the single phase to earth fault. According to Reference /30/, for instance in Nordic countries, about 80 % of all faults are of this type. To develop the protection and fault location systems, it is important to obtain real case data of disturbances and faults which occurred in the networks /35/. Therefore, data of fault occurrences have been recorded and analyzed in the medium voltage distribution networks (20 kV) at two substations, of which one has an isolated and the other a compensated neutral. In the occurring disturbances, the traces of phase currents and neutral currents in the beginning of two feeder and the traces of phase voltages and neutral voltage from the voltage measuring bay were recorded.

In addition to the measured data, other information of the fault occurrences was also collected (data of the line, cause and location of permanent faults and so on).

3.2 RECORDER INSTALLATION

Disturbance recorders were installed at the Gesterby substation of Espoo Electricity Co., where the distribution network is isolated and at the Gerby substation of Vaasa Electricity Co., where the network is compensated. Substations, with mostly overhead feeders, were chosen, so that a significant number of circuit breaker operations, during adverse weather conditions, would be likely to occur. The length of overhead lines was 79.3 km and one of the cable lines was 4.2 km in the isolated network and the corresponding lengths were 223.4 km and 5.0 km in the compensated network.

The recorder system was rack mounted and was provided with SPAA 322 and SPAC 531 relays and SPCR disturbance recorders. In both substations, the disturbance recorders were installed at two feeders including five SPCR recorder units for each feeder, three recorder units for the phase voltages and currents and two units for the residual or neutral current and voltage. In the latter case, one recorder unit was set with an increased sensitivity to ensure the identification of transients in the case of high fault resistance. One voltage and one current channel

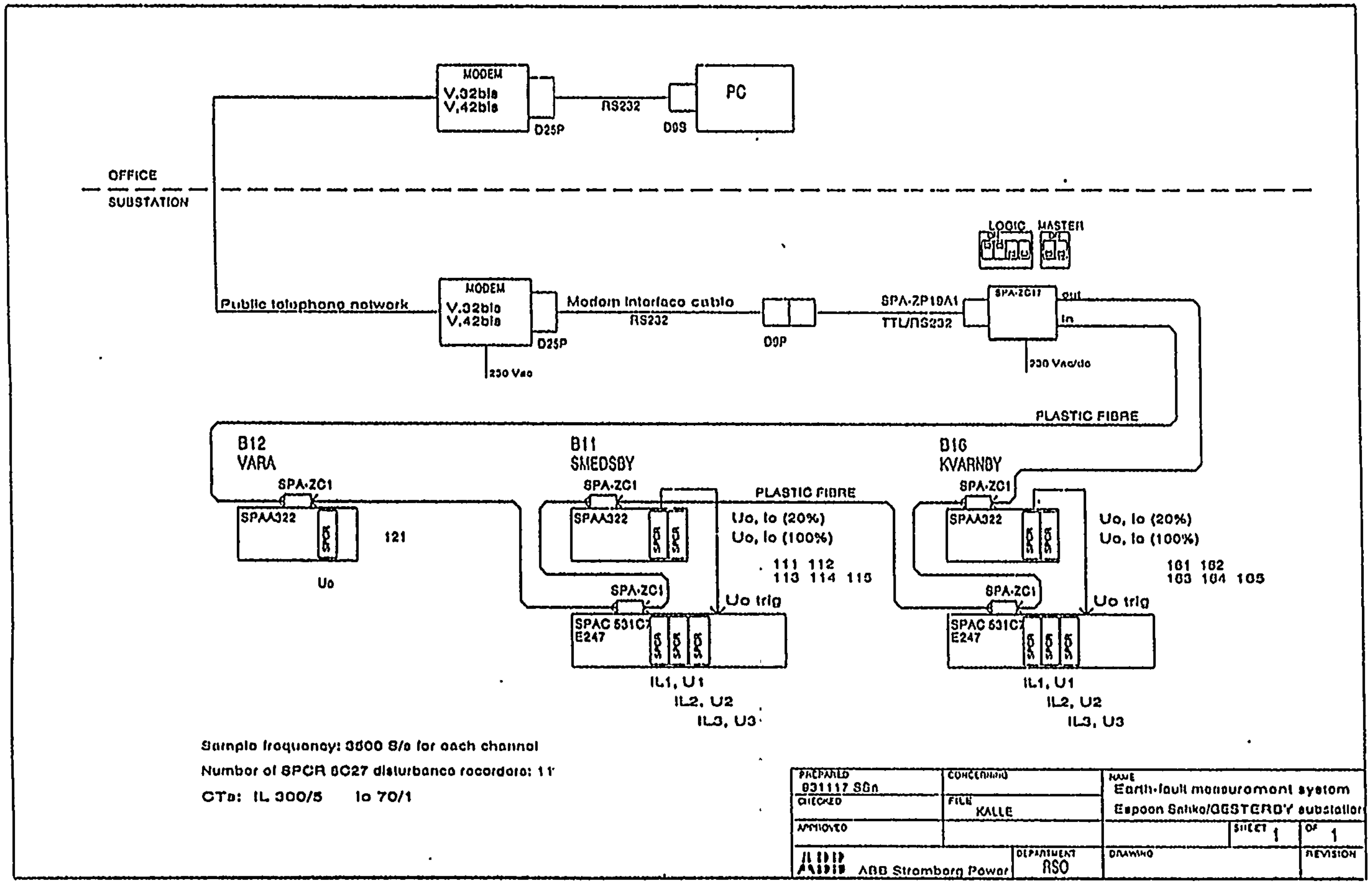

Fig. 5. Installation arrangement of the recorder system at the Gesterby substation.

of each recorder unit was used. For neutral voltage, in addition to those mentioned above, one recorder unit was used, whose duration of each record was selected longer than the one of the other units.

Various triggering options are included within the recorder. In this case, if the predetermined threshold value of the neutral voltage was exceeded in one channel, this initialized the triggering of the other recorder units at the same feeder. The sample frequency was 3.5 kHz for each channel and the length of each recording was 0.5 s in the isolated network and 0.7 s in the compensated network. This also contained some periods of data before the fault moment. The recorders used the majority of their memory as a segmented cyclic buffer to store the sampled data. Once all the memory had been used, the recorder directed new data to the first segment of the buffer and the oldest recording in the memory was deleted.

The disturbance recorders were connected via modems and telephone networks to a PC in the office at VTT. The PC automatically monitored the recorders at selected intervals and if required, transferred the recorded files to the PC for further treatment. The communication software and the recorder equipment had been developed and supplied by ABB Transmit Oy. The schematic diagram of a recorder installation is shown in Figure 5 /28/.

3.3 FAULT CLASSIFICATION

An electrical fault can be defined as any abnormal condition which is caused by a reduction in the insulation strength between energized phase conductors, called a short circuit, or between a phase conductor and earth or any earthed part of an electrical system, called an earth fault. In addition to these two main categories, disturbances were further classified according to how they were cleared. The fault, which disappeared by itself and needed no function of a circuit breaker, was classified as "self-extinguished" (SE). In other cases, the clearing of the fault demanded the function of a circuit breaker. Many faults were cleared by auto-reclosing, high speed auto-reclosing (HSAR) or delayed auto-reclosing (DAR). Sometimes, the fault disappeared after the auto-reclosing during the time from the tripping of the circuit breaker to that, when the circuit breaker was again closed manually with the aid of remote-control (RC). The remainder of the faults were permanent (P) and needed corrective actions in the terrain before the supply could be restored.

3.4 DATA ANALYSIS

During the observation period of about two years at the substations of Gesterby and Gerby, altogether 341 recordings were obtained. This includes all disturbances in the substation busbar. Together 227 of the recordings were obtained from the feeders surveyed. Figures 6 and 7 show the number of faults in the feeders divided into main fault categories and into the way of clearing.

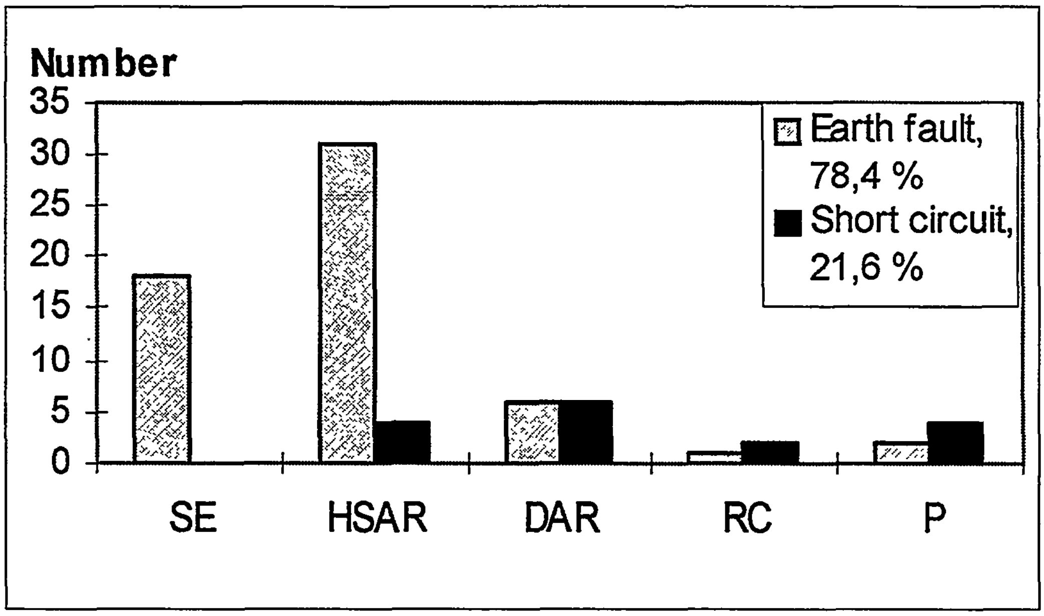

Fig. 6. Number of the disturbances divided into the way of clearing in the unearthed network.

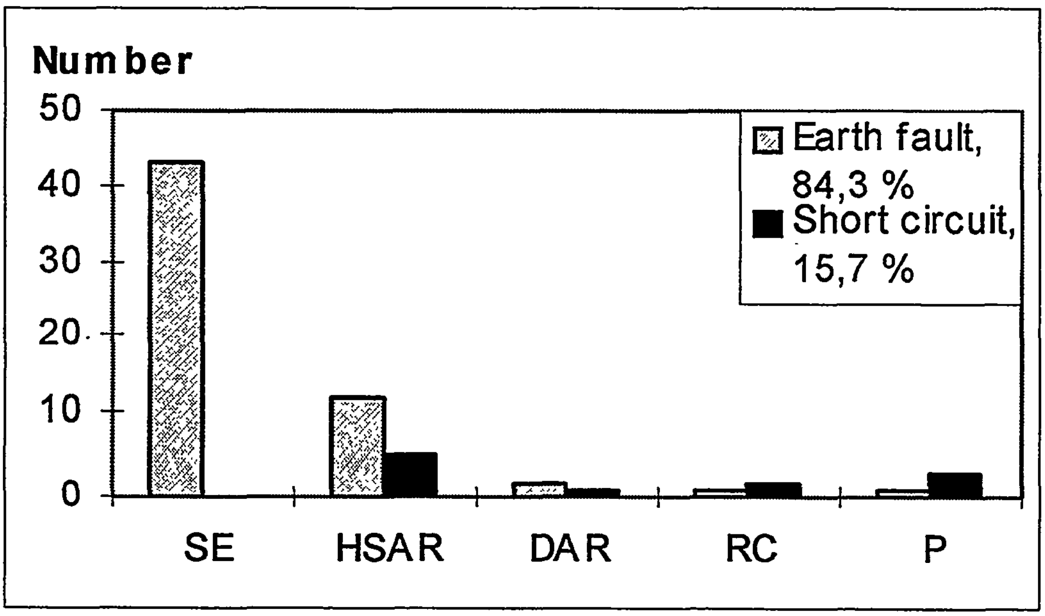

Fig. 7. Number of the disturbances divided into the way of clearing in the compensated network.

In the compensated network, the division of faults into main categories was 59 % for earth faults and 41 % for short circuits. Here the disturbances, which extinguished by themselves without any function of a circuit breaker (SE), were excluded. In the unearthed network, the corresponding numbers were 71 % and 29 %. Due to the difference in neutral earthing and also due to the longer delay of the high-speed auto-reclosing, a bigger share of faults were self-extinguished in the compensated network than in the unearthed network. The analysis also showed that, if the function of the circuit breaker was needed, high speed auto-reclosing (HSAR) usually succeeded in clearing the fault.

Since the recorder units were triggered by the rise of neutral voltage, all the faults analysed involved a ground contact. This material does not give the correct understanding of the ratio of one phase and multiphase fault frequencies. To mitigate this, the recorded fault data were also compared to the corresponding ones which were acquired from a third power company /39/. Here the number of faults was acquired by the aid of numerical relays in the substations. The period surveyed was about three years. Only those disturbances, in which the clearing of the fault needed the function of the circuit breaker, were taken into account. Figures 8 and 9 show that in opposite to the former, the majority of the faults were short circuit faults. However, also here the share of earth faults was bigger in the isolated neutral substations than in the compensated neutral case.

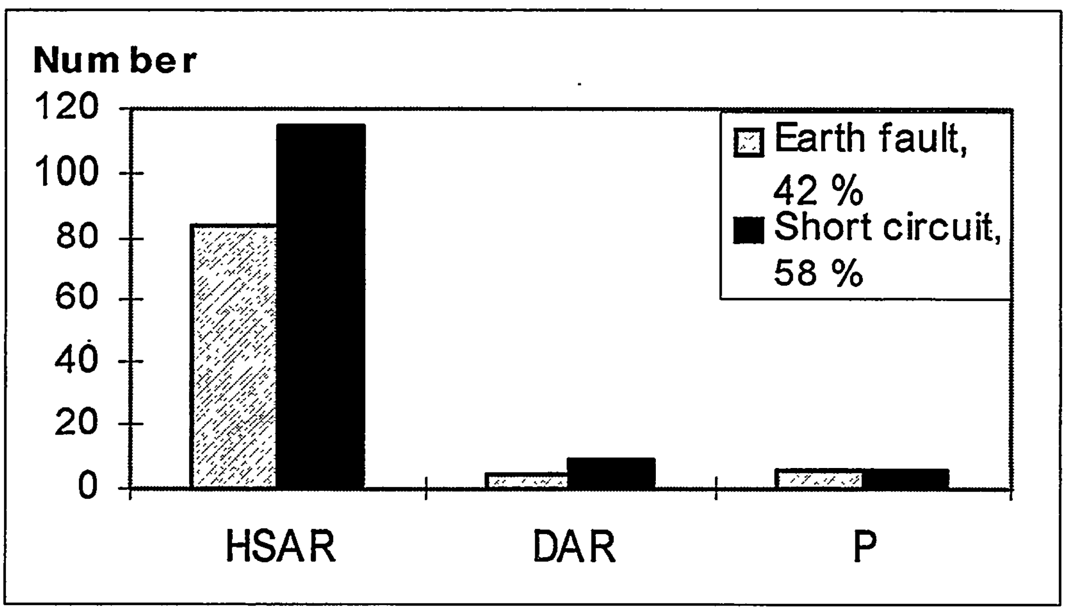

Fig. 8. Number of faults at one substation in the North-Carelian Electricity Co (unearthed network).

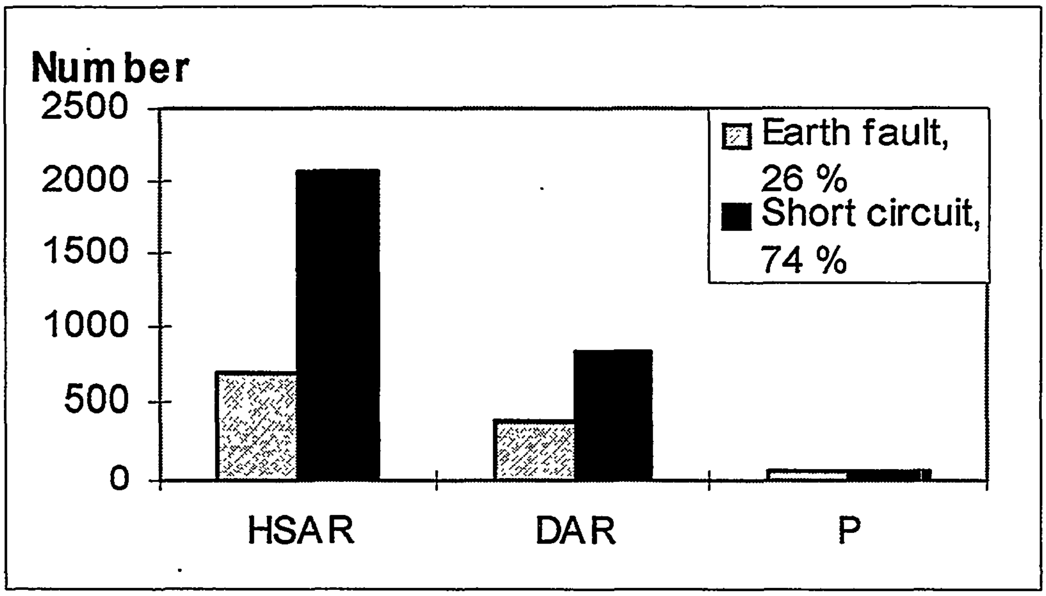

Fig. 9. Number of faults from eight substations in the North-Carelian Electricity Co (compensated network).

Autoextinction

An earth fault arc can extinguish itself without any auto-reclosing function and the interruptions can thus be avoided. The most significant factors, that determine whether the arc will disappear or not, are the voltage transient of the fault arc extinction, and the residual fault current magnitude. During the observation period, the triggering level of the recorders was set a little below the function level of the feeder protection relays, so disturbances that caused no auto-reclosing functions could also be recorded.

The study showed (Figures 6 and 7) that more disturbances extinguished themselves in the compensated network than in the isolated network. With regard to the clearing of disturbances with autoextinction, the average residual current measured was 0.65 A and the maximum current 2.5 A in the unearthed network and correspondingly 6.6 A and 16.9 A in the compensated network. The average duration of these faults was 0.54 s in the compensated network and 0.44 s in the isolated network.

Arcing Faults

During the observation period, it was noticed, that the one phase earth fault was in many cases an arcing fault, especially in an unearthed network. In an arcing earth fault, the arc disappears at the instant there is zero current and strikes afresh when the voltage is re-established. Figure 10 shows the typical current and voltage curves of an arcing fault.

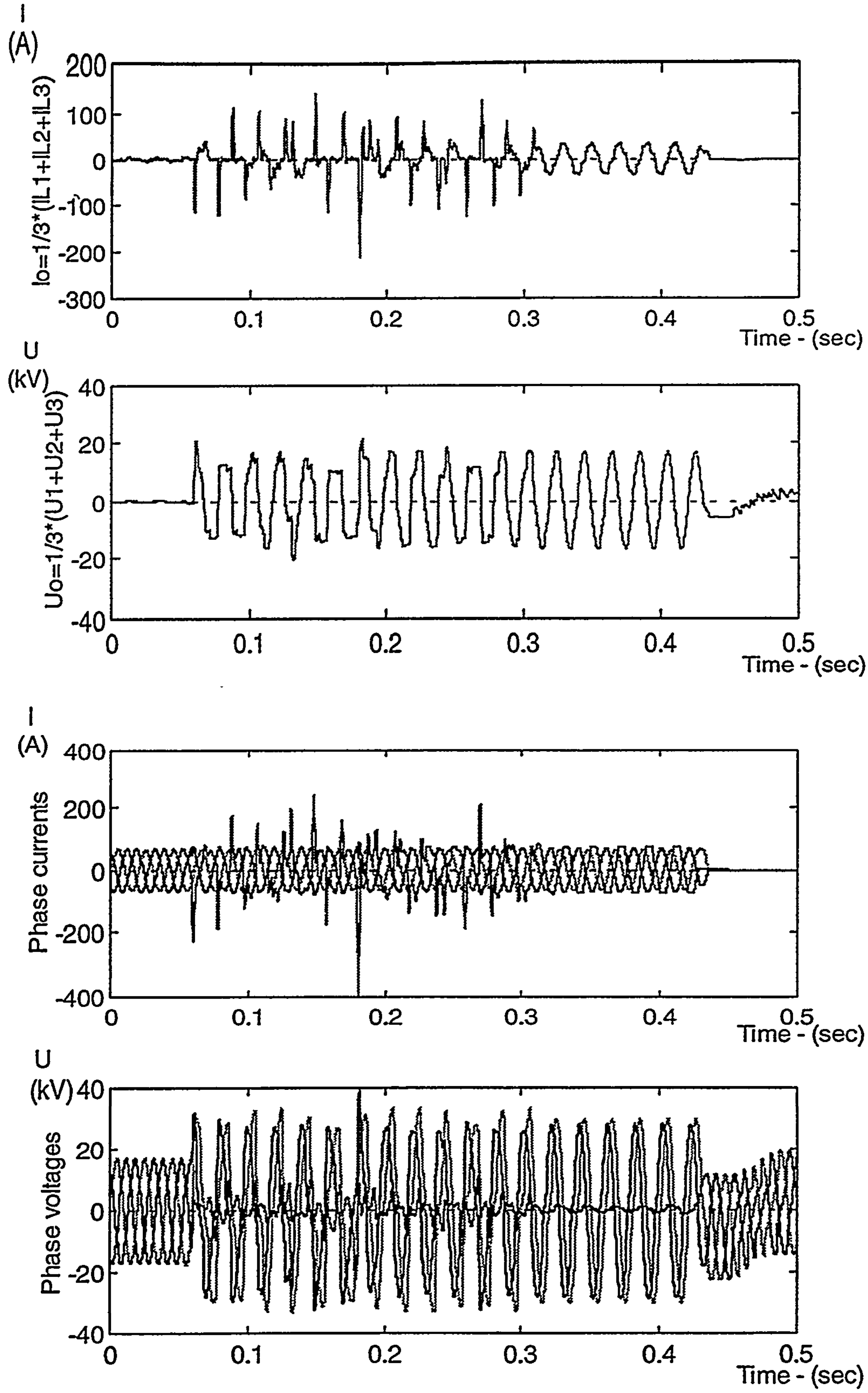

Fig. 10. Neutral current and voltage and phase currents and voltages of an arching fault in the isolated network.

Figure 11 shows, that about half of the disturbances were arcing faults in the isolated network and Figure 12 shows, that only few arcing faults occurred in the compensated network. An explanation for this is the factors which affect the arc extinction and its reignition. Among other things, the amplitude and rising speed of the recovery voltage and the residual capacitive fault current affect this. The major reason, why the arc can strike again more often in the isolated network than in the compensated network, is the rising speed of the recovery voltage, which is much higher in the isolated network /34/.

A number of relay algorithms obtain the fundamental frequency components of both voltages and currents. The performance of these algorithms is dependent on obtaining accurate estimates of the fundamental frequency components of a signal from a few samples. In the case of an arcing fault, the signal in question is not a pure sinusoid and this can cause error in the estimated parameters /36/.

Figure 13 shows the average duration of arcing current classified according to the way of fault clearing in the unearthed network. The arcing current occurred in all cases in the beginning of the disturbances and continued for some network periods prior to altering to a full earth fault or the arc extinguished itself. According to Figure 13, the average duration of the arcing current was 80 ms in the isolated network. The corresponding time was 140 ms in the compensated network, but there occurred only five arcing faults during the whole observation period.

The arcing fault can cause overvoltages in the network, which can in the worst case be dangerous to human beings and destroy electrical equipment. Table 1 and 2 show the max and mean peak value of the phase voltage, measured in the network during an arcing fault and classified according to how the faults were cleared. Table 2 is sparse, because so few arcing faults occurred in the compensated network. Table 1 shows that there occurred no overvoltages during the faults, which extinguished themselves in the isolated network. In other cases, the overvoltages, which were measured, were more than double the normal phase voltage.

Fault Resistances

Figures 14 and 15 show the division of the fault resistances taking into account all disturbance recordings. According to these figures, there clearly were two major categories of earth faults. In the first case, the fault resistances were mostly below 100 Ω and circuit breaker tripping was required. In the other category, the fault resistances were in the order of thousands of ohms. In this case, the neutral potentials usually were so low, that continued network operation with a sustained fault was possible.

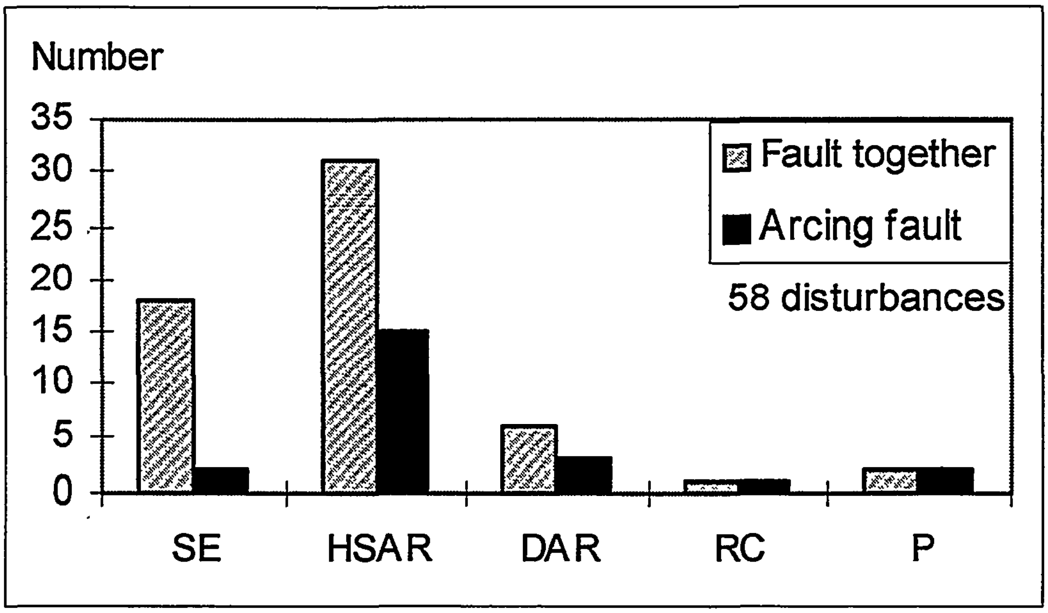

Fig. 11. Occurrence of arcing fault divided into way of clearing in the unearthed network

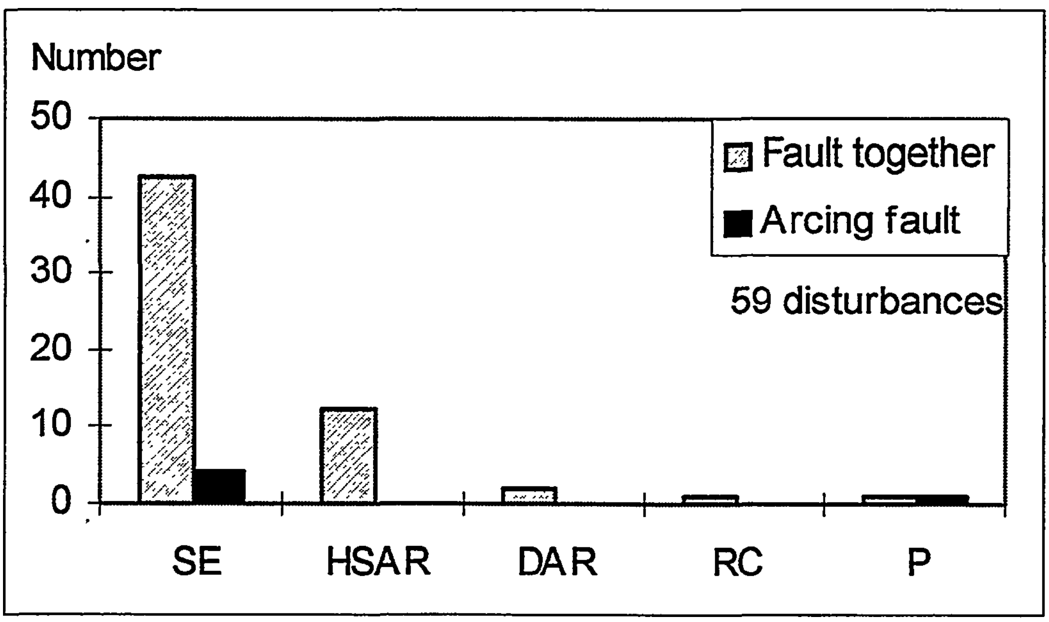

Fig. 12. Occurrence of arcing fault divided into way of clearing in the compensated network.

Table 1. The max and mean peak value of the phase voltage during the arcing fault in the unearthed network expressed in kV.

Phase voltage	*SE*	*HSAR*	*DAR*	*RC*	*P*
Uv,max	*17.67*	*39.87*	*35.63*	*39.03*	*33.37*
Uv, mean	*17.57*	*37.29*	*34.62*	*39.03*	*33.23*

Table 2. The max and mean peak value of the phase voltage during the arcing fault in the compensated network expressed in kV.

Phase voltage	*SE*	*HSAR*	*DAR*	*RC*	*P*
Uv,max	*37.56*	-	-	-	*33.31*
Uv, mean	*37.36*	-	-	-	*33.31*

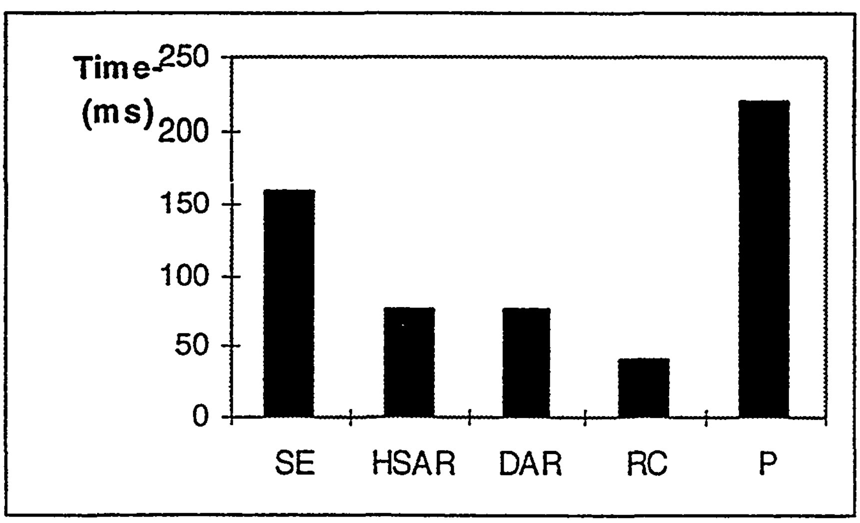

Fig. 13. The average duration of arcing current classified according to the way of fault clearing in the unearthed netwok

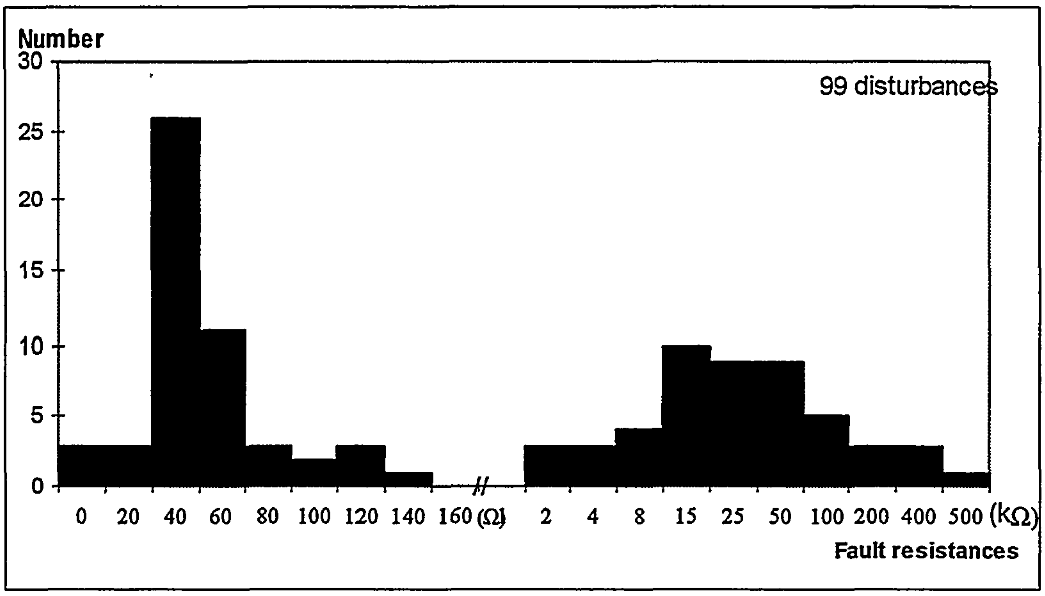

Fig. 14. The division of the fault resistances in the unearthed network.

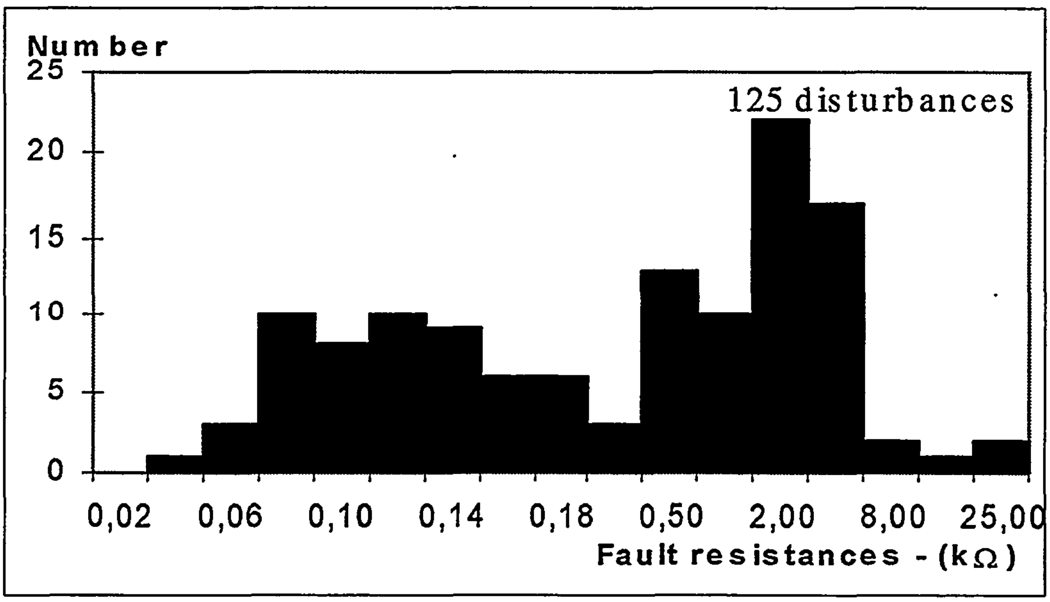

Fig. 15. The division of the fault resistances in the compensated network.

3.5 SUMMARY

The results presented are based on the evaluation of 341 real case data recordings, obtained from substations of medium voltage networks with high impedance earthing. The networks were mainly of overhead construction, with a smaller share of underground cables. In the unearthed network, about half of disturbances were arcing faults. These can lead to overvoltages higher than double the phase to ground normal voltage. Only few arcing faults occurred in the compensated network. An earth fault arc can extinguish itself without any auto-reclosing function and the interruptions can thus be avoided. With regard to the clearing of disturbances with autoextinction, the average residual current measured was 0.65 A and the maximum current 2.5 A in the unearthed network and correspondingly 6.6 A and 16.9 A in the compensated network. The average duration of these faults was 0.54 s in the compensated network and 0.44 s in the isolated network. Fault resistances fell into two major categories, one where the fault resistances were at and below 100 Ω and the other where they were on the order of thousands of ohms

4 THE EFFECT OF EARTH FAULT PROTECTION PRACTICES ON THE FREQUENCY OF OUTAGES IN MV LINES

Ari Nikander and Erkki Lakervi, Tampere University of Technology

In this chapter methods to improve extinction of the earth fault arc in the medium voltage network and reducing the short interruptions to customers are discussed. Earth fault distance estimation with permanent faults and determination of the key parameters of the compensated system are also studied. The three essential targets of this study are the following.

- An economic principle to improve fault arc extinction without a reclosing function is introduced. This novel compensation and protection practice is tested in one rural distribution network. The selective functioning of the active current based earth fault protection was ensured by simulations and field tests. The influence of the star point impedance to the number of short interruptions is discussed.
- The determination of the key parameters of a compensated distribution system by utilizing the simulated and measured data is introduced.
- The earth fault distance estimation by rearranging the affected feeder into a closed ring over an adjacent feeder, is studied. This method was also tested in one rural distribution network.

In the latter part of the chapter different methods to improve extinction of the earth fault arc in the medium voltage network and reducing the short interruptions to customers are discussed. The disadvantages of the rapid autoreclosing functions to customers are studied. Then the influence of star point impedance on the number of short interruptions is discussed. Finally, the feasibility of utilizing shunt circuit-breakers in the Finnish MV networks to extinguish the arc, is studied.

4.1 INTRODUCTION

Customers have become less and less tolerable of even short interruptions of supply. Rapid autoreclosures are especially harmful to those commercial and private customers who have equipment which will be disturbed by these under half second interruptions. Mainly due to the increasing use of distribution automation (e.g. remote controlled switching devices, fault detectors, computational fault spotting) the average interruption period per customer has been reduced. Simultaneously the number of equipment sensitive to short voltage break or dip has increased. Therefore reducing the number of interruptions has become a more essential target.

The improvement of the quality of electric power supply is actually a subject of increasing interest. Therefore a close supervision of distribution systems in order to evaluate the actual state of the system, facilitate an early detection of earth faults or to support preventive maintenance strategies become more and more important. One field of supervision is the total phase to earth admittance of the system and of each of its feeders from the HV/MV substation. Also such key parameters as mismatch, damping and unbalance can be determined.

The computational earth fault distance estimaton without test connections is a demanding task in isolated or compensated distribution systems because the impedance of the radial MV line between the substation and fault location has no significant effect on the fault current. A new method for earth fault distance estimation is also presented in this chapter.

4.2 NEUTRAL TREATMENT OF MEDIUM VOLTAGE SYSTEMS

The single phase to earth fault is the most common fault type in medium voltage networks. In rural conditions distribution transformers are small and horn gaps are widely used for the overvoltage protection. Most of the earth faults cause an arc at its location. Treatment of the neutral in the medium voltage system has a major influence on the system behavior during an earth fault. Extinction of an earth fault depends on the behavior of the recovery voltage and the magnitude of the residual fault current.

Circuit breakers, especially in overhead line networks, are equipped with rapid and delayed autoreclosing devices. The neutral earthing policy has a considerable effect on the disappearing of the earth fault arcs and therefore it directly affects the number of short interruptions to customers.

A novel compensation and protection practice

The compensation of the earth fault current can be carried out by means of several small compensating units located at different points in the network. (decentralized compensation). This cost effective practice is applied in some rural utilities in Finland. The main reason for this practise has been the need to reduce hazard voltages with earth faults without expensive improvement of protective earthings.

The essential target of this study was to introduce a new economic principle to improve fault arc extinction without the reclosing function in isolated or partially compensated networks. The compensation degree can be raised to the same level as with traditional centralized resonant earthing (equipped with control automation) in the primary substation. A principle to determine the relay settings and ensure the selective functioning of directional relays by utilizing the ATP model is also studied.

We have studied the potential of a considerably increased compensation degree because this has an essentially positive effect on the extinction of the arc and considerably reduces the number of short interruptions to customers. The present decentralized compensation practice with about a 50 % compensation degree does not have this positive effect. A considerable part of the compensation capacity can be located in the primary substation. It is practical to place a minor part of the compensation capacity at the end of the longest feeders so that a roughly self-adjusting system could be achieved. The characteristics of the directional earth-fault relays must then be changed because the protection can no longer be based on the reactive current measurement. The selectivity may be based on the measurement of the active current component. Nowadays cheap 20 A compensation units are available. The inductance of the coil can be adjusted in 2.5 A steps between 15 A and 25 A. The unit includes both a suppression coil and an earthing transformer with YNd-connected windings. The control of the coil can be done step by step via the remote control system.

This kind of combination of fixed centralized and decentralized compensation has been tested from summer 1996 at one rural 110/20 kV substation. A 16 MVA substation transformer feeds six overhead line feeders. The combined line length of the network is 573 km, so that the MV feeders are very long (72 - 133 km). Before the experiment four (5/3.5 A) compensation units were connected in the network, two (2*5 A) at the substation and two (2*3.5 A) at the end of MV feeders. In the new compensation experiment two 5 A units at the substation were replaced by one new 20 A compensation unit which was adjusted to a 25 A position. The network and location of the compensation units are illustrated in Figure 16.

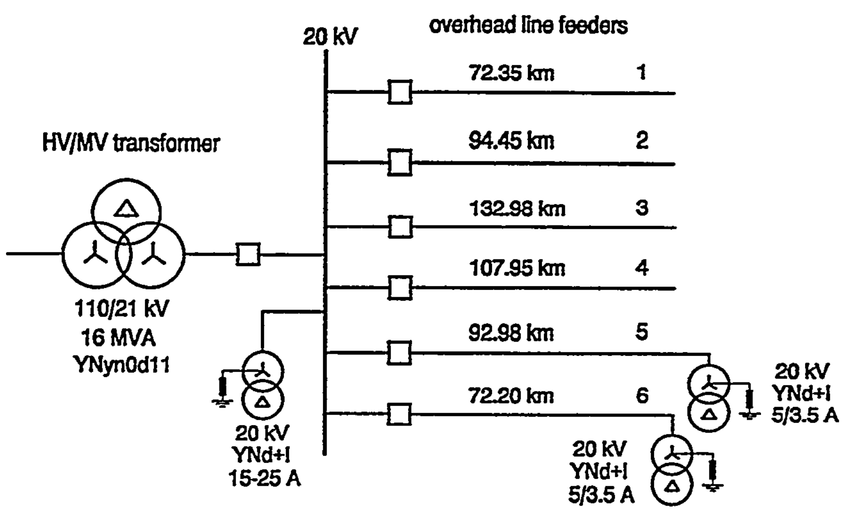

Fig. 16. MV network used in the compensation experiment.

New relay settings

Modern numerical earth fault relays with Icosφ measurement at the substation are used. New active current measurement based relay settings were calculated by utilizing the ATP version of the EMTP program. The dynamic model for the whole network (Figure 16) was developed by using ATP-models for the the overhead lines, primary transformer, circuit breakers and star point components. By utilizing TACS (Transient Analysis of Control Systems) functions ("devices") the instantaneous value curves of the zero sequence voltage and zero sequence currents of the feeders were converted to square waves whose amplitude is one. They can thus be synchronized and it is possible to determine the phase shift of the zero sequence voltage and the current of the appropriate feeder. As a simulation result we also get the instantaneous and RMS-values of the zero sequence voltage, phase voltages, zero sequence currents and phase currents of the feeders, earth fault current and star point currents of the compensation units.

The major task is to take care of the adequacy of the active current component which ensures the selective functioning of the protection. Sometimes the magnitude of this component is very small and must be increased by means of an additional star point resistance. This resistance may be located either centrally in the secondary star point of the substation transformer or in the compensation units.

The selective functioning of the relay protection was checked in advance by an ATP-model of the network. An earth fault with fault resistance was made in every feeder in turn. The zero sequence currents of the faulted and healthy feeders, zero sequence voltage and phase angle between them were obtained as simulation results. According to our calculations the resistive component of the fault current produced by the compensation units (previously mentioned 20 A and 3.5/5 A units) and overhead line network itself is usually adequate for the directional earth-fault relays (approximately 3.7 A).

Results of field experiments

At the beginning of every six feeders one phase to earth fault was made in sequence. All tests were made with three values of the fault resistance 0 Ω, 500 Ω and 1000 Ω. The zero sequence voltage and the zero sequence currents of the feeders were measured and synchronized with each other. With every fault resistance the earth fault protection tripped the faulted feeder selectively and no malfunction of the protection was observed.

The new 20 A compensation unit is connected to the substation busbar via a remote-controlled disconnector. The position message of the disconnector is transferred to the numerical relays. Thus the characteristics of the directional relays change automatically if the disconnector is controlled. When the disconnector is closed and the compensation unit is connected to the network the earth fault relays function with Icosφ (active current measurement) characteristics. When the disconnector is opened the characteristics change to Isinφ (reactive current measurement). Thus we can also ensure the functioning of the protection with exceptional connection arrangements and prevent a considerable overcompensation of the network.

This kind of compensation system has been in use since the end of July 1996 at one 110/20 kV substation. No rapid autoreclosing function has been registered since the end of July although excitations of an earth fault relay caused by zero sequence voltage have been noted more than ten times. The arcs have extinguished themselves within the response time. In the future the number of autoreclosings will naturally be registered and compared to the statistics made before the experiments.

Benefits

The main benefits of this previously described protection and compensation practice are

- low earthing and hazard voltages
- savings in earthing costs
- low rising speed and amplitude of the recovery voltage (improves the self extinction of the arc)
- low fault current (improves self extinction of the arc)
- lower fault current makes it possible to increase the tripping delay of the earth fault protection (more time for self extinction)
- selective earth fault protection for any network connection
- overcompensation of the network or feeders does not lead to malfunctions of protection
- significantly lower investment costs than in centralized compensation equipped with automatic resonance control of the coil (but as good conditions for self extinction of the arc)

4.3 DETERMINATION OF THE PHASE TO EARTH ADMITTANCE AND OTHER KEY PARAMETERS IN A COMPENSATED MV POWER DISTRIBUTION SYSTEM

The target of the study was to determine out the method of measuring the total phase to earth admittance and unbalance of each feeder of a HV/MV substation. The method is based on the measurement of the residual currents of each feeder with two different zero sequence voltages.

In the case of a compensated power distribution system the necessary variation of the neutral point to earth voltage can be obtained by modifying the star point impedance of the system or by modifying the galvanic length of the network (ie. adding or switching off one or several feeders).

The capacitive part of the total phase to earth admittance of the feeder allows an estimation of its "live" length. The resistive part can theoretically be used to detect highly resistive earth faults, taking into account climatical conditions and comparisons with other feeders. The determination of the phase to earth admittance of the whole network makes it possible to calculate the earth fault current much more accurately than by using rough table values of earth capacitances from the network data base of the distribution network company.

Using two different values of the neutral to earth voltage and corresponding residual currents of the feeders it is also possible to determine the key parameters of a compensated distribution system, unbalance, mismatch and damping. These parameters have been defined by Eq. (1) - (3). We consider a HV/MV substation with n feeders whose equivalent circuit is presented in Figure 17. It is assumed in this method that the residual currents and the neutral to earth voltage are available as complex values, so the magnitude and the phase angle of their fundamental signal must be calculated from the measured signals.

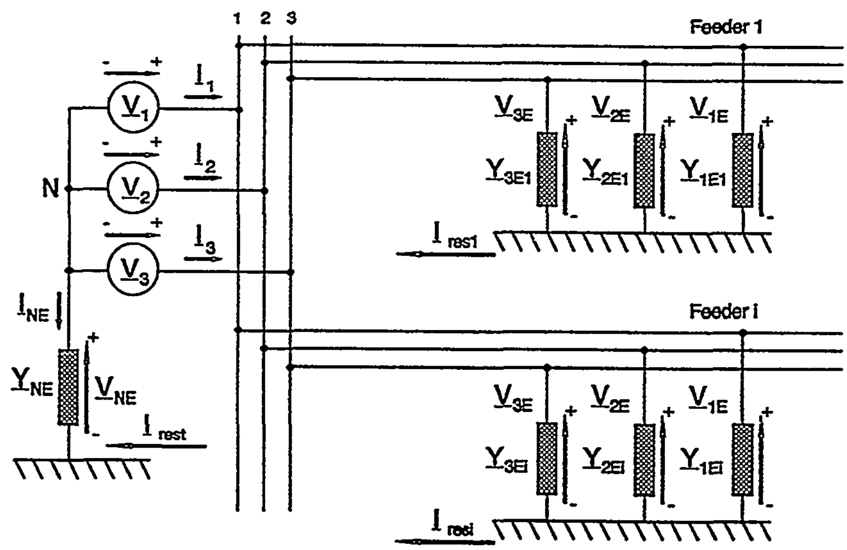

Fig. 17. Simplified equivalent circuit of a compensated distirbution system.

<u>Unbalance k:</u>

$$\underline{k} = \frac{\underline{Y}_{1E} + \underline{a}^2 \underline{Y}_{2E} + \underline{a}\underline{Y}_{3E}}{j\omega C_{tE}} \qquad (1)$$

$$\underline{a} = -\frac{1}{2} + j\frac{\sqrt{3}}{2}$$

<u>Mismatch m:</u>

$$m = \frac{\frac{1}{\omega L_{NE}} - \omega C_{tE}}{\omega C_{tE}}, \quad -1 \leq m < \infty \qquad (2)$$

m = -1	:	uncompensated (isolated) system
-1<m<0	:	undercompensated system
m = 0	:	completely compensated system
m > 0	:	overcompensated system

Damping d:

$$d = \frac{1}{R_{tE}\,\omega C_{tE}}, \quad \frac{1}{R_{tE}} = \frac{1}{R_{NE}} + \frac{1}{R_{1E}} + \frac{1}{R_{2E}} + \frac{1}{R_{3E}} \tag{3}$$

Normalized neutral to earth voltage v_{NE}:

$$\underline{v}_{NE} = \frac{\underline{V}_{NE}}{V_{nom}} = \frac{\underline{k}}{m + jd} \tag{4}$$

The algorithms for calculating the key parameters from the measured residual currents and zero sequence voltages were tested by using the ATP program. TACS (Transient Analysis of Control Systems) was used to convert the simulated residual currents and the neutral to earth voltages to complex values.

Possible applications

Some possible applications of the described method are:

- estimation of the galvanic length of the feeder using the information about its total phase to earth capacitance (more accurate calculation of fault current and hazard voltages)
- detection of resistive earth faults
- estimation of the values of the key parameters describing the state of the distribution system: unbalance, mismatch, damping

4.4 ESTIMATION OF THE DISTANCE TO THE EARTH FAULT

Distribution networks are normally operated radially. The distance to earth fault information can be obtained by rearranging the faulted feeder into a closed ring over some healthy feeder. The distribution of the fault current is directly proportional to the distance to the fault from each feeder. The method usually requires a compensation of the earth fault current. Using two different values of the neutral to earth voltage and corresponding residual currents of the feeders it is also possible to determine the phase to earth admittances between the fault location and the substation along both feeders.

The described earth fault distance estimation was tested by utilizing simulation results (ATP network model). The method was also tested in practice in one rural distribution network in summer 1996. The feeders 3 and 6 of Figure 16 were connected into a closed ring by remote controlled isolator. The fault resistances studied were 50 Ω, 500 Ω and 1000 Ω. The preliminary results were quite promising. The distances between the fault location and the substation along both ring connected feeders was calculated in all cases from the distribution of the fault current. The average deviation in the ratio of the distances was below 5 % and the average deviation of the fault distance below 1.3 km. The length of the whole ring was 123 km. In the near future the network data will also be utilized to enable distance estimation to be more accurate.

4.5 DISADVANTAGE OF RAPID AUTORECLOSING FUNCTIONS TO CUSTOMERS

Customers have become less tolerable of even short interruptions of supply. Rapid autoreclosures are especially harmful to those commercial and private customers who have equipment which will be disturbed by these under half second interruptions. Mainly due to the increasing use of distribution automation (e.g. remote controlled switching devices, fault detectors, computational fault spotting) the average interruption period per customer has been reduced. Simultaneously the amount of equipment sensitive to short voltage break or dip has increased. Therefore reducing the number of interruptions has become a more essential target.

Economic evaluation of short interruptions concerning autoreclosures used to clear temporary faults in overhead line networks is difficult. Usually an evaluation of the disadvantage requires a detailed study of certain customers and cases. Furthermore the disadvantage can vary largely depending on the day and season, for instance.

An attempt to determine the disadvantages of short interruptions was made by relatively brief questionnaire studies directed to residential and agricultural customers of two rural utilities, Rovakaira Oy and Kainuun Sähkö Oy. In Rovakaira the questionnaires were sent by mail to customers. In Kainuun Sähkö customers were interviewed in their homes and the questionnaires were filled in together with the customer. Most of the interviewed customers (66 %) in Rovakaira remembered 2 - 5 short interruptions during the last year. In Kainuun Sähkö only 40 % of the customers remembered 2 - 5 and 50 % many short interruptions. If in some feeder dozen rapid autoreclosures happened during the last year over one third of the customers had noticed a large number of interruptions. None of the customers interviewed reported more interruptions than had actually happened. Usually customers remembered fewer short interruptions than they had in reality experienced. The number of rapid autoreclosing operations is distributed unevenly during different seasons. A major part of the autoreclosures occurs in summer during a thunderstorm period and in early autumn during the migration of birds.

Over 60 % of the households consider short outages just a little harmful. The more a customer has noticed short interruptions the more harmful he considers them. If a customer has not noticed short outages at all he considers them mainly harmless. About 80 % of households are ready to accept 2 - 5 short interruptions per year. If a customer has experienced many interruptions during the past year, a willingness to accept short outages is reduced considerably.

Reducing the number of short interruptions caused by temporary earth faults requires investments. Therefore one part of the questionnaire surveyed the willingness of the customers to pay for the avoidance of the outage and the disadvantage caused by it.

4.6 NEUTRAL TREATMENT OF MEDIUM VOLTAGE SYSTEMS

The single phase to earth fault is the most common fault type in medium voltage networks. In rural conditions, distribution transformers are small and horn gaps are widely used for the overvoltage protection. Most of the earth faults cause an arc at its location. The treatment of the neutral, in the medium voltage system, has a major influence on the system behavior during an earth fault /34/. Extinction of an earth fault depends on the behavior of the recovery voltage and the magnitude of the residual fault current.

Circuit breakers, especially in overhead line networks, are equipped with rapid and delayed autoreclosing devices. The neutral earthing policy has a considerable effect on the disappearance of the earth fault arcs and therefore it directly affects the number of short interruptions to customers.

4.7 FEASIBILITY OF UTILIZING SHUNT CIRCUIT-BREAKERS IN FINNISH MV NETWORKS

One possibility for extinguishing an earth fault arc in a MV network is by using a shunt circuit-breaker, to earth the faulted phase at the feeding substation in the case of an earth fault (Figure 18). The original fault is then short-circuited. This phase earthing method can be used to extinguish arc-type earth faults or to reduce the hazard voltage at the fault place in permanent faults without causing a break in the power supply.

An earth fault in a MV system with an isolated or resonant earthed neutral has been surveyed based on literature. Requirements of the safety regulations for earth fault protection have been reviewed. The coming CENELEC (European Committee for Electrotechnical Standardization) regulations have been dealt with based on the most recent standard draft /38/.

The basic functioning of the phase earthing system has been presented. Special attention has been paid to the implementation of the relaying and to the necessary conditions for arc extinction to take place.

4.7.1 Modelling of phase earthing system

An equation for the residual current of the fault location has been derived with the aid of symmetrical components. The effect of load and the effect of the method of system earthing on the residual current have been taken into account, Eq. (5) /31/. The connection of the sequence networks is illustrated in Figure 19. The earth potential rise at the fault location has been evaluated and the connection between it and the voltage drop of a line has been presented. The residual current in fault location is:

$$\underline{I}_e = \frac{3\underline{U}_v\,(R_L 3R_s - \underline{Z}_{mc}\underline{Z}_1)}{2\underline{Z}_1 R_L(3R_s+\underline{Z}_{mc})+3R_s\underline{Z}_{mc}(\underline{Z}_1+R_L)+(\underline{Z}_1+R_L)(3R_s+\underline{Z}_{mc})(\underline{Z}_0+3R_f)} \tag{5}$$

where

$\underline{U}_v$	is phase to earth voltage
R_L	loading resistance
R_S	earthing resistance of shunt circuit-breaker
R_f	fault resistance
C_0	phase to earth capacitance
$\underline{Z}_m$	star point impedance
$\underline{Z}_{mc}$	impedance of parallel connection of $\underline{Z}_m$ and C_0
$\underline{Z}_1$	positive sequence impedance of the line
$\underline{Z}_0$	zero sequence impedance of the line.

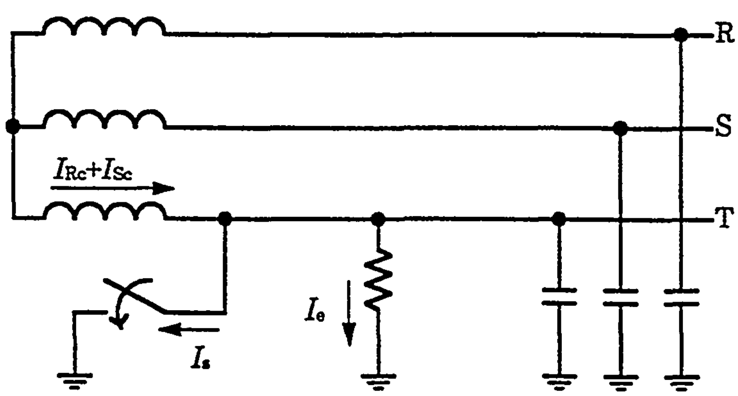

Fig. 18. Principle scheme of phase earthing system. $I_e = I_{Rc}+I_{Sc}-I_s$.

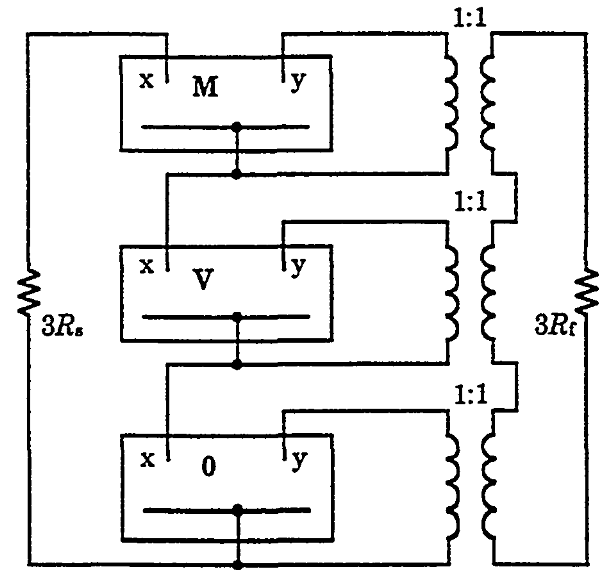

Fig. 19. Combination of sequence networks with phase earthing system. R_s is resistance of shunt circuit-breaker, R_f is fault resistance, x is the location of shunt circuit-breaker and y is the location of the fault.

4.7.2 Applicability in Finnish MV networks

Finally, the possible ways of using this method in Finland have been considered. Especially in isolated MV networks the limit for the residual current self extinction of the arc is so low that the earth fault arc does not usually extinguished without an autoreclosing function.

The functioning of the shunt circuit-breaker does not cause a voltage break to low voltage customers. One disadvantage of the phase earthing system is that the extinction of the arc also depends on the load condition of the feeder. The influence of the load current can be reduced by a resistor connected series with the shunt circuit-breaker. The use of this series resistor is advantageous especially in heavy load conditions.

Both domestic and foreign experiences of the earlier use of the phase earthing system have been gathered. At present the system is widely used in France and Ireland. It has been used both in isolated and resistance earthed systems. According to these experiences about 50 - 75 % of single phase to earth faults have been cleared by this system. The phase earthing system is also used with permanent faults to make continuation of the power supply possible during the fault.

In this study a method was presented to determine the maximum earthing voltage in a fault location based on a voltage drop of the line. The fault resistance has a significant effect on the earthing voltage. With low values of fault resistances the earthing voltage is a fraction of a voltage drop of a line.

The use of the phase earthing system to clear temporary earth faults and to reduce short interruptions to customers in Finnish MV overhead line networks is possible. Compared to the centralized compensation of the earth fault current, the cost of the shunt circuit-breaker equipment is modest.

The utilization is limited mainly by recent Finnish safety regulations. The system is the least suitable for networks where very short tripping times of the earth fault protection must be used or where the earth fault current will be strongly increased for example as a consequence of increasing underground cabling in the future.

It is not possible to use the method to maintain the supply to customers during permanent faults until a reliable method of checking the fault potential rise has been developed.

5 EVENT ANALYSIS IN A PRIMARY SUBSTATION

Pertti Järventausta, Harri Paulasaari, Tampere University of Technology Jarmo Partanen, Lappeenranta University of Technology

The target of the project was to develop applications which observe the functions of a protection system by using modern microprosessor based relays. Microprosessor based relays have three essential capabilities: communication with the SCADA, the internal clock to produce time stamped event data, and the capability to register certain values during the fault. Using the above features some new functions for event analysis were developed in the project.

5.1 THE DETECTION OF HIGH IMPEDANCE EARTH FAULTS BY USING A RESIDUAL OVERVOLTAGE RELAY MODULE

High impedance faults in the neutral isolated network are difficult to detect. The fault current is low and the natural unsymmetry of the neutral isolated network makes it impossible to set the operation values of the directional neutral overcurrent relay module at such a low level. When the fault resistance of the earth fault is zero, the residual voltage can raise until it is equal to the phase voltage. When the fault resistance is low, the residual voltage may rise even above the phase voltage. In the case of a high impedance earth fault, the residual voltage is a sensitive indicator.

In some earlier installations in Finland, specialised unlinear transducers were used to produce accurate measuring signals of the residual voltage in substations. This study tries to collect information on how a slight variation in the residual voltage during a high impedance earth fault can be detected by the common residual overvoltage relay module.

In the project the measuring system has been implemented in one distibution company, Alajärven Sähkö Ltd. The medium voltage network of the company is earth isolated. The selectivity of earth fault protection is generated by using a directional earth fault relay in every feeder of the substations. The directional earth fault relay measures the residual voltage U_0, the zero current I_0 and the angle between them. The network topology does not affect the selectivity when directional earth fault relays are used. The residual voltage relay serves as an emergency protection when the earth fault relay is broken. In this study the residual voltage relay is used, but all the setting values are left in the original position. The company has a UNIX-based SCADA. The 20 kV feeders are provided with new microprocessor based relays. The SCADA standing in the control room collects fault data via the communication system and RTU's, Fig. 20. All the data collection procedures use SCIL-language in the SCADA.

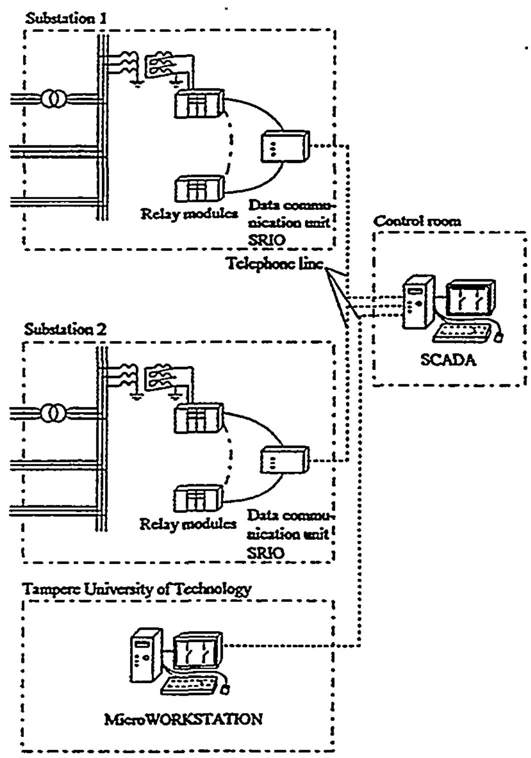

Fig. 20. Connections between the relays and the control center in Alajärven Sähkö Ltd.

Relay registrations in a continuous situation

The SCADA samples the residual voltages registered by a residual overvoltage relay module once a minute. It stores the values in a data object which includes samples of 48 hours (i.e. 48h*60 sample/hour = 2880 samples). A tool image of the neutral voltage monitoring (Fig. 21) utilitises this collected data. The results of registrations can be utilised in high impedance fault detection. Experience has shown that a common residual overvoltage relay module can detect slight variations in a residual voltage caused by snowstorms or faults.

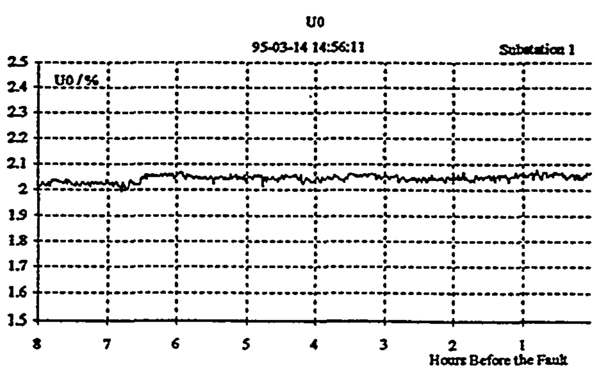

Fig. 21. An example of the measured neutral voltage:

Relay registrations in fault situations

The residual overvoltage module sends an event, E1, to the communication unit (SRIO) when the measured residual voltage exceeds the tripping stage of U_0. The time markings are added to the event immediately in the relay module. The SCADA notices the protection module event when the value of the process object changes. This activates the event channel connected to the process object. The event channel activates the command procedures which collect data from various protection modules. This procedure determines the type of event and the source module of the event. When the measured residual voltage falls below the tripping stage of U_0 the residual overvoltage module sends the information to the SCADA (event E2). The SCADA then sends a query to the residual overvoltage module asking the values of the various registers. The following data is written to the hard disk of the SCADA after each operation of the residual overvoltage module:

96-09-01 07:50:17 SÄNKIAHO
SÄNKIAHO HAVAHTUI EV=1 96-09-01 07:50:17.133
SÄNKIAHO PALAUTUI EV=2 96-09-01 07:50:17.223
V1=30.00000 V2=1.000000 V4=6.000000 S2=3.000000 U=20.20000

The operating time of the residual overvoltage module can be calculated using the stored time stamps of each event. The stored registers are:

- V1, the highest measured residual voltage during the operation
- V2, the number of operations
- V4, the operation time of U_0> -stage
- S2, the setting of time delay of U_0> -stage
- U, the measured busbar voltage

In 1996 the system stored 70 operations of the residual overvoltage modules of the two substations in Alajärven Sähkö Ltd. The residual voltage, the exact operating time and the operation of autoreclosing have been analysed for each fault, as follows:

96-09-01 07:50:17
SÄNKIAHO
U_0 = 3.50 kV
operation time = 90 ms
no autoreclosing (i.e. extinguished)

From the 70 operations of the residual overvoltage modules, two were associated with faults which caused the final operation of the protection system. Forty three faults were cleared up by the autoreclosing facility. Twenty five faults extinguished themselves; the residual voltage varied from 2.55 kV to 13.80 kV and the operating time from 50 ms to 385 ms (less than the setting of the time delay of the protection system).

5.2 CONTINUOUS MONITORING OF THE PROTECTION SYSTEM

The protection system should operate very reliably. This can be ensured by using off-line testing of the protection system. A fault forms a test of the protection system, too. Based on a real fault situation it is possible to determine how a relay operated and how it should operate using the registered and other setting values of the relays. Comparison of the time stamped events with the supposed function reveals whether the relay has operated correctly. Thus the need of off-line testing can be decreased.

In the project a demonstration system for checking the correct operation of the protection using the registered data on relay events has been developed. The first version of the system has been installed in Alajärven Sähkö Ltd. A more advanced application is in use in a laboratory of the Tampere University of Technology.

The demonstration system

The Tampere University of Technology has a relay panel for teaching and research purposes (Fig. 22). The panel contains two outgoing feeders modelling 20 kV distribution. The feeders and busbar protection cubicle are provided with microprocessor based relays. The relays are connected to the SRIO by an optic fibre cable. The communication unit polls all the protection units continuously and if the polled value has changed, it sends data to the SCADA. The SCADA is connected to the SRIO by a serial line. One part of the project has been the implementation of the relays, the SRIO and the SCADA.

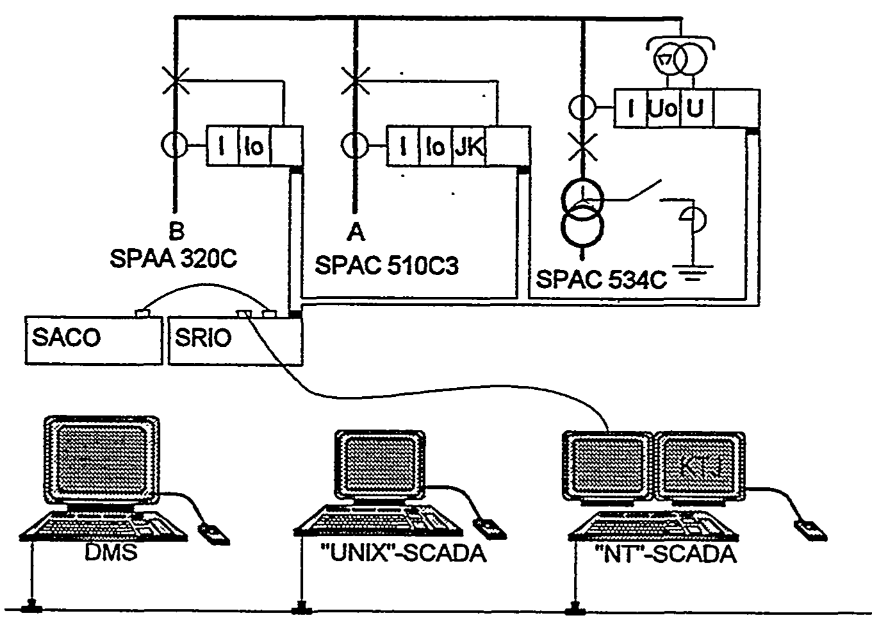

Fig. 22. The relay panel at Tampere University of Technology.

The settings (i.e. mask) of the relays have been changed so that all the relay events are transferred through the SRIO to the SCADA which stores the events to the hard disk. The following shows an example of the relay events associated with a permanent short-circuit fault simulated by the relay panel:

```
1 71 96-08-07 12:52:45.939 E1*
1 111 96-08-07 12:52:45.939 E1*
1 113 96-08-07 12:52:46.259 E7*
1 116 96-08-07 12:52:46.314 E1*
1 111 96-08-07 12:52:46.334 E2*
1 113 96-08-07 12:52:46.759 E3*
1 116 96-08-07 12:52:46.804 E2*
1 111 96-08-07 12:52:46.849 E1*
1 71 96-08-07 12:52:46.854 E1*
1 113 96-08-07 12:52:47.158 E7*
1 116 96-08-07 12:52:47.205 E1*
1 111 96-08-07 12:52:47.233 E2*
1 113 96-08-07 12:52:52.149 E3*
1 116 96-08-07 12:52:52.197 E2*
1 71 96-08-07 12:52:52.239 E1*
1 111 96-08-07 12:52:52.244 E1*
1 111 96-08-07 12:52:52.689 E3*
1 116 96-08-07 12:52:52.742 E1*
1 113 96-08-07 12:52:52.744 E9*
1 111 96-08-07 12:52:52.749 E2*
```

Using the stored event data the developed application determines:

* what has happened (e.g. which relay module is responsible for the operation of the circuit-breaker)
* the operating times of the tripping relay (i.e autoreclosing, final operation)
* the times the voltage is cut off during an autoreclosing sequence
* the operating times of the circuit-breaker

The application compares the determined values to the set values. In addition the application shows all the relay modules which have operated (i.e. have detected a fault) with their operating times and settings. Fig. 23 describes the dialog box which shows the results of event analyses. The application has been implemented using C++ -language. It is run in the distribution management system (DMS) computer (see Fig. 22 and the chapter "Distribution management system").
In the installation in Alajärven Sähkö Ltd. the relay masks of the busbar protection terminal and two feeder terminals in one primary substation have been changed so that all the relay events are transferred to the control center SCADA. The SCADA is responsible for the basic event analysis for checking the protection operation.

In the project, the event analysis functions have been developed to be run in the control center systems. So far the data transmission from a primary substation to the control center is the bottleneck for a wider use of the functions, because all the relay events should be transferred. The methods developed are applicable at the primary substation level with the data transmission capacity at present, or at the control center level where the data transmission will be evolved.

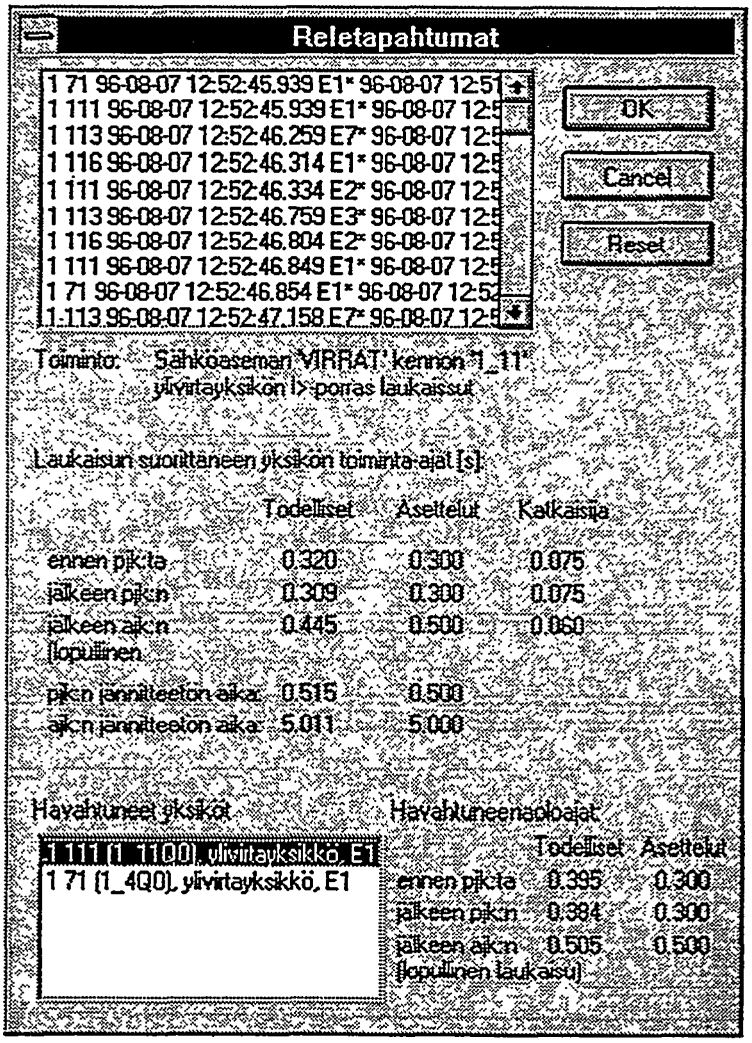

Fig. 23. The user interface for showing the results of event analysis.

6 A DISTRIBUTION MANAGEMENT SYSTEM

Pertti Järventausta, Pekka Verho, Matti Kärenlampi, Mikko Pitkänen, Tampere University of Technology, and Jarmo Partanen, Lappeenranta University of Technology

6.1 INTRODUCTION

The development of new distribution automation applications is considerably wide nowadays. One of the most interesting areas is the development of a distribution management system (DMS) as an expansion to the tradional SCADA system. At the power transmission level such a system is called an energy management system (EMS). The idea of these expansions is to provide supporting tools for control center operators in system analysis and operation planning.

Nowadays the SCADA is the main computer system (and often the only) in the control center. However, the information displayed by the SCADA is often inadequate, and several tasks cannot be solved by a conventional SCADA system. A need for new computer applications in control center arises from the insufficiency of the SCADA and some other trends. The latter means that the overall importance of the distribution networks is increasing. The slowing down of load-growth has often made network reinforcements unprofitable. Thus the existing network must be operated more efficiently. At the same time larger distribution areas are for economical reasons being monitored at one control center and the size of the operation staff is decreasing. The quality of supply requirements are also becoming stricter.

The needed data for new applications is mainly available in some existing systems. Thus the computer systems of utilities must be integrated. The main data source for the new applications in the control center are the AM/FM/GIS (i.e. the network database system), the SCADA, and the customer information system (CIS). The new functions can be embedded in some existing computer system. This means a strong dependency on the vendor of the existing system. An alternative strategy is to develop an independent system which is integrated with other computer systems using well-defined interfaces. The latter approach makes it possible to use the new applications in various computer environments, having only a weak dependency on the vendors of the other systems. In our research project this alternative is preferred and used in developing an independent distribution management system.

This text describes the basic models and functions of the intelligent distribution management system, which has been developed in the research project. The basic platform was developed by the end of 1995. In 1996 and 1997 new applications (e.g automatic switchings) have been developed, the domain has been enlarged to comprise the low-voltage networks and subtransmission networks, and the computer system integration has been extented (e.g. full-duplex communication with the SCADA, open relational database connection with the AM/FM/GIS). The following gives a general description of the distribution management system as a whole. The results of the project are described in more detail in references /11-15,22-24,48-51/.

6.2 AN OVERVIEW OF DISTRIBUTION MANAGEMENT SYSTEM

The distribution management system is an intelligent decision support system for distribution network operation and management. The DMS is an autonomous part of an integrated environment composed of the distribution automation (e.g. protection relays), the SCADA, the AM/FM/GIS, the geographical database, the customer database, and telephone answering machine, as illustrated in Fig. 24. The overall aim of the DMS is the minimization of the operational costs (e.g. power losses, outage costs) subject to the technical constraints (e.g. voltage level, thermal limits, the operation of protection). The DMS includes many intelligent and advanced applications useful for the control center operator in network operation, as shown in Fig. 25. The application functions are based on the sophisticated modeling and calculation methods, and data interfaces.

The basic idea of the usefulness of the DMS is the integration and the use of various external computer systems which have traditionally worked separately. The SCADA provides connections to the distribution automation devices (e.g. relays, fault detectors) offering real-time information on events, measurements and the status of switches. The AM/FM/GIS contains a vast amount of detailed and versatile data on existing networks. The data on the terrain conditions of line sections and roads, and the geographical background maps are stored in the geographical database. The data (e.g. annual demands, customer groups) in the customer database is used for modeling the loads and outage costs. The automatic telephone answering machine serves customers' trouble calls.

The DMS presents the real-time electrical state of the distribution network. It can inform the operator of various abnormalities (e.g. faults, voltage drops, overloadings) and propose necessary actions. In everyday use the operator can study the real state of the network or make some investigations in a simulation state. The use of the DMS is based on interactiveness, where the operator is responsible for the ultimate decision making and for performing the switchings or other proposed actions (e.g. changing of the protection relay settings). In a fault situation the DMS may also make some automatic switchings in an unmanned control center.

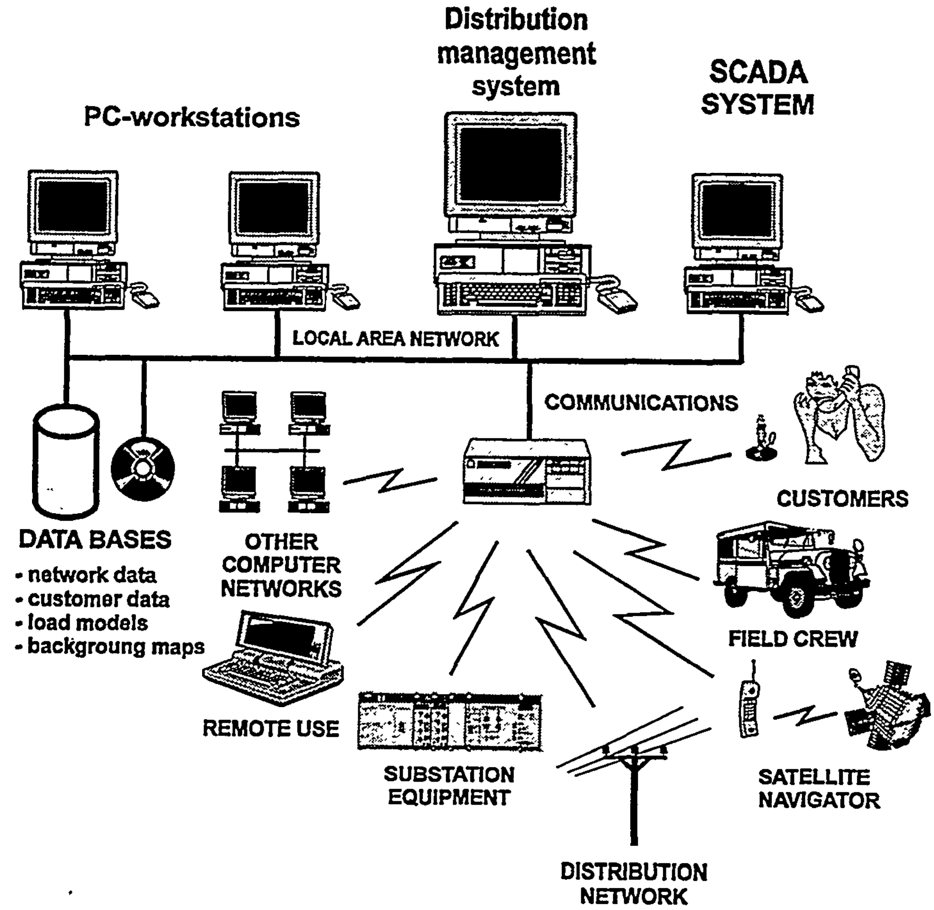

Fig. 24. The integration of the distribution management system.

The interactive graphical user-interface of the DMS (see Fig. 26) is based on the standard MS-Windows including multiple windows, mouse control, color graphics, and explanation texts. The basis of the user-interface is a geographically formed network image on background maps. The scale of the viewed background maps depends on the zooming scale. If a large network map is viewed, the background map is part of a large-scale map, and for a small scale zoom, a map with high resolution is used. The network image has active mouse functions for zooming, selection and diagram generation. The diagram has active functions for changing the switching status, network tracing and checking the numerical member variables. The colors in the network image visualize the inference and calculation results. The graphical views are supplemented by text windows to inform the user. One advantage is that the DMS provides the same common graphical user-interface for different purposes (e.g. for the answering machine).

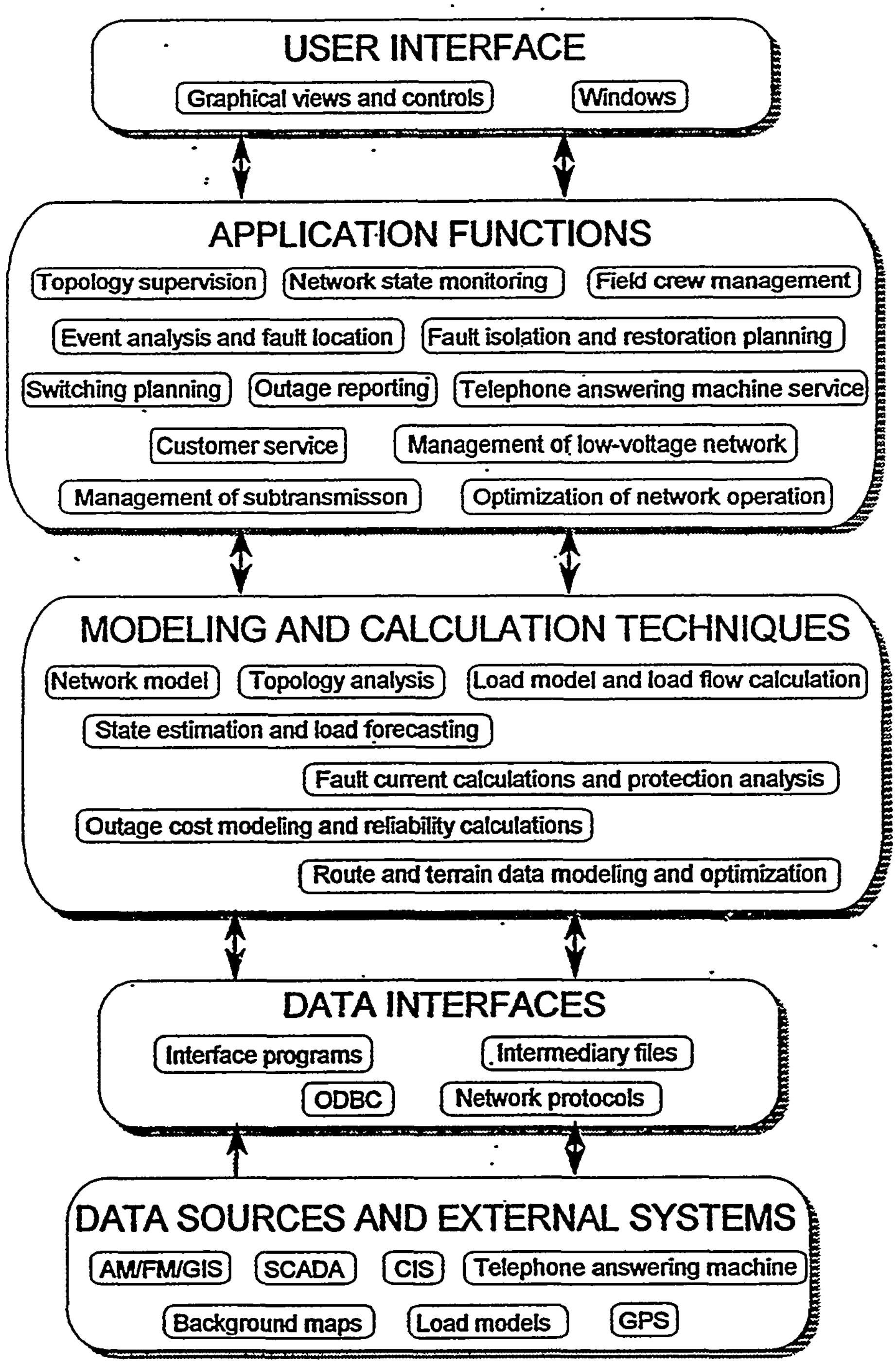

Fig. 25. The layers of the distribution management system.

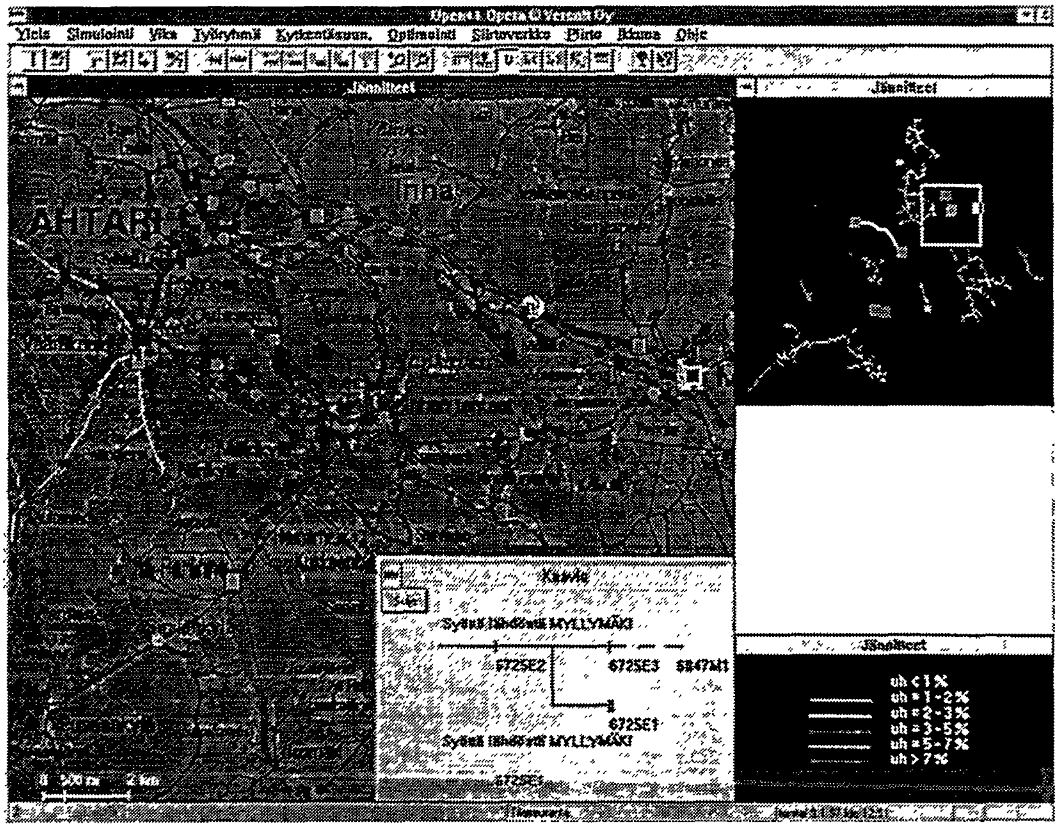

Fig. 26. An overview of the graphical user interface.

6.3 THE SCADA CONNECTION

The DMS and the SCADA are connected using application program interfaces (API) .based on TCP/IP data transmission protocols (see Fig. 27). Berkeleyn Sockets are used with Unix operating systems and Windows Sockets with Windows operating systems.

An application which works as a server of the support system interface (SSI) has been connected as a part of the SCADA. The client connected to the server is a part of the DMS. Like a client-server model the client is the active part of the connection. Once the connection has been formed, the client and the server use the defined messages of the SSI for data transmission. The connection is full-duplex. The switching, measurement and event data is transferred cyclic and event based from the SCADA to the DMS, and the switching commands of remote controlled disconnectors and circuit-breakers are send from the DMS to the SCADA. The client application of the SSI is independent on the SCADA vendor.

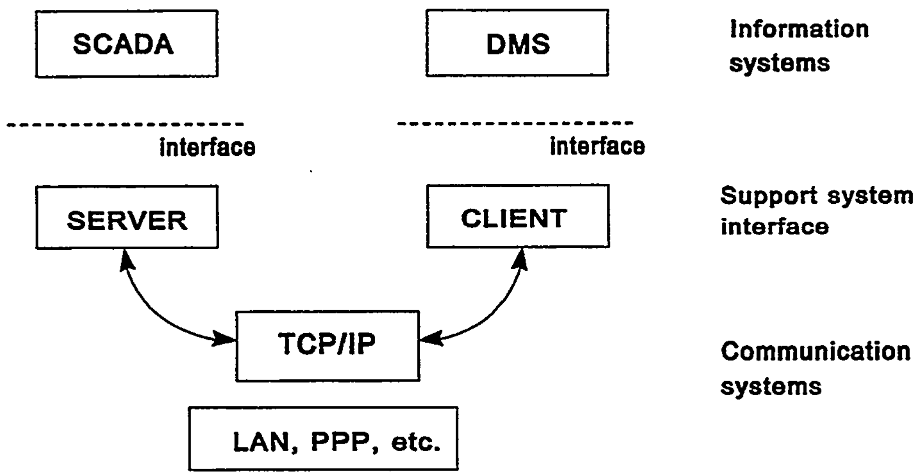

Fig. 27. Levels of the support system interfaces.

The simpler half-duplex SCADA connection was built using intermediary files, which were updated by the SCADA system and monitored as a background process by the DMS. The disk sharing was implemented using the NFS (Network File System). In one-way integration the file-based connection proved to be rather serviceable and easy to develop.

Network database integration

A separate program is used to generate the object-oriented network model of the DMS as a daily or weekly background process. The interface program has access to the network database, from which the data needed is read and processed through the LAN. The changes in network data (new lines and reinforcements) are updated to the AM/FM/GIS database by its own applications. The use of standard database management systems in the AM/FM/GIS simplifies the interface further with possibilities to use SQL queries. The idea of open system architecture makes the integration of the systems of different suppliers feasible. With new techniques like Open Database Connectivity (ODBC) the open system architecture is more easy to utilize. So far the integration of the DMS has been implemented using both the file-based network data and a commercial relational database.

6.4 MODELING AND COMPUTATION TECHNIQUES

6.4.1 Network model

The core of the DMS is an object-oriented network model, which represents the real-time or simulated state of the network. The main objects are line sections and different kind of nodes. In addition to the topology information the objects also have data members to model the static (line type, coordinates, etc.) and dynamic (voltage, power, switching status, etc.) component data. The network model forms a common blackboard through which the different modules, including various problem solving methods, can operate interactively with each other. The memory resident network model provides a high-speed computational capability for a real-time application.

6.4.2 Topology analysis and load flow calculation

The topology analysis uses the static network model and dynamic switching state information for connectivity analysis and to construct a real-time network model. The DMS detects abnormal or erroneous switching states causing de-energized line sections and substations or closed loops. The determined line sections without voltage and the feeders that are meshed are displayed on screen to help the operator to detect the errors in the switching state.

The developed load flow procedure uses the objects of network model, but for efficiency it is not completely object oriented. The effect of randomness and uncertainties can be considered statistically in load flow calculations, because the load models for 46 customer types present the load as a random variable using Gaussian distribution. When the loads in all nodes of the network are presented as random variables, the load flow calculations can be performed using the statistical confidence limits (e.g. 10% excess probability) needed to check violations of the technical constraints. To get the best possible load flow results the load models for customer groups have to be extended to include power factors and load-voltage dependences.

6.4.3 State estimation and load forecasting

In state estimation the load flow results, i.e. the sum of substation loads plus losses, are compared with the load measurements available at least at primary substation (110/20 kV), where the feeder currents and the busbar voltage are measured. In this case redundant information on loads is available and weighted least squares estimation can be used to estimate the loads for distribution substations more accurately. The standard deviation of load measurement (standard error) as well as the standard deviations of the modeled loads are used as weights in the estimation.

The state estimation results are used to form dynamic load models for distribution substations, which in turn are used to determine the final load forecast when the temperature forecast is available. The dynamic load model for a distribution substation includes loads for the next week, i.e. for the next 168 hours. A dynamic load model for a distribution substation is formed by adjusting the load calculated by the static load models of different customer groups by the average ratio of the estimated and modeled loads calculated in the state estimation of the respective hours during the last two week period. When the system is connected real-time to the SCADA, state estimation is performed at least once an hour and the dynamic load models of substations are updated. Every hour forecasts for the next week's respective hour are updated and a one week load forecast is thus constantly available.

6.4.4 Fault current calculation and protection analysis

In addition to load flow calculation fault current analysis is needed for checking the acceptability of the network operation. With relay setting information the protection can be analyzed and ensure the acceptability for monitoring and planning purposes.

6.4.5 Outage cost modeling and reliability calculations

The outage costs can be seen by the utility or by the customer. The evaluation of the outage costs met by the customers is based on the value of non-distributed energy, which can be over one hundred times greater than the value of distributed energy. In Finland some studies have been carried out to determine this value for different customer groups. In the DMS the hourly outage cost parameters (constant and time-dependent outage cost values) for each distribution transformer are maintained in addition to the load forecast. In the DMS the outage costs are used to determine restoration priorities and in calculating the sum of expected hourly outage costs in the network as an operational reliabilty index.

6.4.6 Road and terrain data modeling and route optimization

The road data and terrain conditions of overhead line sections have been stored in the geographical database. Road sections are classified into five types and each type has its own traveling speed and transition time. The road network model is utilized in optimizing the routes and calculating the moving times of the crew. The fastest route between two points is sought using Dijkstra's algorithm.

6.5 APPLICATION FUNCTIONS

6.5.1 Topology supervision

The network topology supervision function is the basis for all other applications. The positions of the remote controlled switches are obtained from the SCADA system and the states of the manual switches are updated manually to the DMS using the field crew information. In addition to the switching state information, also a line stump can be set to be as open. Using the switching state information the actual network topology is analyzed by the DMS. The network topology is presented on the screen using different colors to distinguish line sections supplied by different feeders or by different primary transformers. The de-energized line sections are shown in white and the loops are shown in red.

6.5.2 Network state monitoring

Hourly state estimation is performed to monitor the electrical state of the network and to check whether the state is accceptable or not, i.e. whether any technical constraints are violated in the network. As a result of the state monitoring function, all line sections where short circuit currents, voltage or load currents violate or are near to violating specified constraints are always presented color-coded on the screen. The DMS uses also alarm lists and audio alarms giving information on the reason of the alarm.

To keep the network in an accepted state all the time, the state monitoring can be done in advance using the load forecasting results for distribution substations and temperature forecasts. Planning the remedial controls needed to remove the constraint violations is supported by an interactive process. In voltage or load capacity problems the possible remedial controls are voltage regulation, switching of capacitors, changing of open points and load-shedding in extreme cases. The protection problems can be removed by changing the relay settings or the open points of the network.

6.5.3 Field crew management

The field crew management function provides a tool for supervision of the working groups and optimization of the driving routes. The working group information needed is stored in a crew database. The crew data includes, for example, persons, the vehicle and location of the group. The location of the group is pointed on the geographic map on the screen, or obtained from the global positioning system (GPS) manually or automatically. The real-time connection to the control center has been demonstrated using GSM communication. In a local use, the notebook connected directly to the GPS device is a considerable help to the field crew in locating themselves.

6.5.4 Event analysis and continuous monitoring of the protection

The detection of high impedance earth faults

The aim of the project was to collect information on how the slight variation in the residual voltage during a high impedance earth fault can be detected by the common residual overvoltage relay module. In the project the measuring system has been implemented in one distibution company, Alajärven Sähkö Oy. So far this function has not been implemented as a part of the DMS.

Relay registrations in continuous situation: The SCADA samples the residual voltages registered by a residual overvoltage relay module once a minute. It stores the values in a data object which includes samples of 48 hours. A tool image of the neutral voltage monitoring utilitises this collected data. The results of registrations can be utilised in high impedance fault detection. The experiences have shown that a common residual overvoltage relay module can detect slight variations in a residual voltage caused by snowstorms or faults.

Relay registrations in fault situations: The residual overvoltage module sends an event to the communication unit (SRIO) when the measured residual voltage exceeds the tripping stage of U_0. After that the SCADA sends a query to the residual overvoltage module asking the values of the various registers. In 1996 the system stored 70 operation of the residual overvoltage modules of the two substations in Alajärven Sähkö Oy. The residual voltage, the exact operation time and the operation of autoreclosing have been analysed for each fault. From 70 operation of the residual overvoltage modules two were associated with faults which caused the final operation of the protection system. 43 faults were cleared up by the autoreclosing facility. 25 faults extinguished by themselves; the residual voltage varied from 2.55 kV to 13.80 kV and the operation time from 50 ms to 385 ms (less than the setting of the time delay of the protection system).

Continuous monitoring of the protection system

The protection system should operate very countable. This can be ensured using off-line testing of the protection system. A fault forms a test to the protection system, too. Based on a real fault situation it is possible to determine how a relay operated and how it should operate using the registered and setting values of the relays. Comparison of the time stamped events with the supposed function reveals wheather the relay has operated correctly. Thus the need of off-line testing can be decreased.

In the project a demonstration application for checking the correct operation of the protection using the registered data on relay events has been developed. So far the application has been implemented in the laboratory of the Tampere University of Technology. The settings (i.e. event mask) of the relays have been changed so that all the relay events are transferred through the SRIO to the SCADA and further to the DMS. Using the stored event data the developed application determines:

* what has happened (e.g. which relay module is in responsible for the operation of the circuit-breaker)
* the operation times of the tripping relay (i.e autoreclosing, final operation)
* the times the voltage is cut off during autoreclosing sequence
* the operation times of the circuit-breaker

The application compares the determined values to the setting values. In addition the application shows all the relay modules which have operated (i.e. have detected a fault) with their operation times and settings.

Event analysis

The basic event analysis in a case of permanent fault is made by the protective relay, other substation automation and the SCADA system. In this analysis the faulted feeder, the type of fault (earth fault, 2-phase short circuit, 3-phase short circuit), the measured fault current and detected fault indicators are determined. In some cases deeper analysis is needed by the DMS to detect the possible malfunctions of the protective devices and concurrent events. The analysis is also used to produce an assumption of the cause of the fault (e.g. arc, fallen tree, etc.).

The DMS have a capability to handle temporary faults, too. The SCADA system sends all the received relay events further to the DMS through the TCP/IP-messages based support system interface. The DMS informs the operator, which feeder is under operation of the time-delayed autoreclosing. All autoreclosing occurrences are analysed so that they are shared to feeders and distribution substations. The autoreclosing occurrences affecting a certain distribtion substation are stored in the database.

6.5.5 Fault location

In a fault situation the available data is transferred from the SCADA via the LAN to the DMS, which forms a deeper object model of the faulted feeder and inferences the possible fault locations. The sequence from the opening of a circuit breaker caused by a fault to the DMS screen illustrating the possible fault locations is carried out automatically without any operator actions in about 10-30 seconds. In short circuit faults the calculated fault distance is the main information used in the inferencing. The electrical distance between the feeding point and the fault location is determined by comparing the calculated fault currents with the measured short-circuit current and the type of fault, which are registered by iP-based protection relays. The possible fault locations are ranked using information on other sources (e.g. fault detectors, terrain conditions, weather information, lightning data). Fuzzy sets are used to model the knowledge and information as various membership functions in the inference model. By combining the fuzzy sets, alternative fault locations can be achieved and arranged according to their feasibility based on all the available information on the existing fault situation. Table 3 shows the usefulness and availability of different information.

Table 3. The importance and availability of the information used in inferencing for fault location.

Information / inference rule	importance/stress	availability
fault distance	very high	good
fault detector operations	high	good
terrain conditions alone	light	fairly good
terrain conditions with weather inform.	medium	fairly good
real-time lightning data	medium	weak
overloading	light	good
fault sensitive components	light	weak
fault sensitive areas	medium	fairly good

6.5.6 Automatic fault isolation and network restoration

The DMS includes inference models which support the planniñg of the switching operations during a fault situation. The switching planning problem can be divided into the switchings for locating and isolating a fault, and for restoration of the unfaulted network using back-up connections.

The isolative switching operations are performed in two phases: first by remote controlled disconnectors and then using manual operations. Using the possible fault locations, the DMS determines the most likely faulted remote controlled zone. If one obvious exists (e.g. tele-monitored fault detectors are provided and the fault distance is known), the faulted remote controlled zone can be determined quite easily without any unnecessary switchings. If no obvious exists, "zone by zone rolling" strategy has been applied. As a result of an experimental switching, the system knows one or more zones which do not include the fault. These zones can be restored during the fault location.

The last immediate operation needed in fault management is restoration of the supply of interrupted customers. The restoration planning can be made interactively or indepently by the system. The impact of the switching operations on the network is analyzed and the constraints are checked. Like fault isolation, the remote controlled restoration operations are performed before manual operations. The search for the best alternative is carried out using heuristic model-based inference. The outage areas are restored in order of importance determined according to the outage cost. In the remote controlled phase the back-up connection with the largest remain capacity is preferred and in the manual phase the fastest (based on moving time) manually operated one with sufficient capacity is preferred. If one back-up connection is not sufficient, several back-up connections or load transfers are used, and in the last alternative the customers with the lowest outage costs are not restored.

So far the DMS has only proposed the switchings to the operator, who has been responsible for the ultimate switching actions. Evaluation of the switching planning models in real fault situations has shown that they yield switching plans which are reasonable and could be automated.

An automatic switching planning application has been developed using the above switching planning models. The application is in responsible for all remote controlled switching actions of disconnectors and circuit-breakers using the novel TCP/IP -messages based full-duplex SCADA connection, which permits to send switching commands automatically from the DMS. All inferencing is performed using an existing real-time switching status. All network calculations (e.g. for checking the technical constraints of switching the back-up connection) are done using prevailing load conditions. If any unexpected information or measure are detected during the switching process, the automatic operation is canceled. The application has been installed in the Koillis-Satakunnan Sähkö Oy. for a real test use in the end of the May 1997 after the successfully and extensive laboratory and field testing. In the first phase the automatic operation comprises the network composed of 4 long feeders. The total length of the 4 feeders is almost 300 km. The feeders include 23 remote controlled disconnectors at 7 disconnector stations.

6.5.7 Lightning location system

The lightning data can be obtained from the centralized lightning location system of the national meteorological institute or from a local lightning detector. The real-time data transfer from the centralized system is a problem. Thus the possibility of using the local lightning detector, named StormTracker, was studied.

StormTracker consists of direction-finding antenna installed on the roof, and receiver board and software installed in a PC. StormTracker uses a direction-finding antenna to receive and locate the radio signals produced by lightning. The strenght of the received signal is used to calculate approximately how far the strike is away. In spring 1997 StormTracker was installed in the laboratory of Tampere University of Technology and in the control center of Koillis-Satakunnan Sähkö Oy. At the same time StormTracker was integrated to be used in the DMS. StormTracker writes the lightning data continuously in a file, where the DMS reads the lightning data through the LAN. The lightnings are shown on the DMS screen so that the colors of each lightning illustrates the timing. The accuracy of lightning data has been tens of kilometers, which means that the application is useful only for monitoring the approach of a thunder storm (i.e. speed and direction). This information is profitable for control center operators to plan the needed measures (e.g. duty of field crew) in preparing to the thunder storm.

6.5.8 Outage reporting

When the fault has been repaired, the operator makes a report on the fault. The DMS offers tools for fault reporting. The application determines and fills in some reported issues automatically while the others are filled in by the operator using dialog boxes. The calculation of the values describing the extent of the fault is a valuable support. All the switching actions during a fault situation are automatically stored in a file. Using these switchings, the DMS can later simulate the network restoration. The task is to inference the outage time of each distribution substation. For each outage part the application calculates the number of disturbed distribution substations and associated hours, the number of disturbed customers and associated hours, and the amount of non-delivered energy. The DMS supports the outage reporting also in maintenance outages.

The DMS database includes separately the outage values of each distribution substation on the amount of outages and the sum of durations in both faults and maintenance outages during a year. The values are determined automatically using the outage report desribed above. The database includes the amount of autoreclosing occurrences, too. Thus the DMS can inform the user, for example, on the total outage time of a calling customer as a customer service.

6.5.9 Telephone answering machine

In a fault situation customers call the control center to report that they have no supply. Most of the calls simply mean additional work and are a waste of the operator's time in MV-feeder faults. A call is valuable only if a customer knows the exact location of the fault. An automatic telephone answering machine therefore means better customer service and gives the operator more time to concentrate on fault location and network restoration.

The telephone answering machine is composed of a PC provided with a soundcard and application software. It can be connected to the direct numbers or subnumbers of a telephone exchange. It can answer several calls simultaneously. The answering machine is also connected to the LAN, and a real-time connection to the DMS has been built. The DMS is used to state for the answering machine how to answer depending on the outage situation.

In MV-feeder faults the initial fault information is created automatically without any user actions. The information is updated by the operator through the user-interface of the DMS. When a customer dials the trouble call number of the utility, he/she hears a real voice stating the reason and the range of interruption, and the phase and expected time of restoration. If the customer has some important information (e.g. he/she knows the fault location), he/she is asked to dial another number, where the operator answers. In the case of a fault in a low-voltage network, the answering machine informs that there is no fault in the MV-network, asks the customer to check his own fuses, and requests him to dial the other number to reach the operator. A maintenance outage resembles the MV-feeder fault situation with the exception that the operator forms the primary information.

6.5.10 Customer service and the management of low voltage network

Whatever user selected low-voltage (LV) network can be shown on the screen. The selection can be founded on the distribution substation or a customer as below. The DMS reads the network data of the selected LV-network and creates dynamically a memory resident object-oriented network model. The load-flow calculation of the LV-network is executed at same time using the hourly load curves. Several LV-networks can be shown at the same together with the MV-feeders. The user can select which voltage level has the focus.

To enhance the customer service of operators and other personnel the DMS includes customer information transferred from the customer information system. One main target is to show the location of a customer calling the control center. The operator has a list of all customers on the screen and he can choose the calling customer according to his name. The DMS immediately shows on screen the distribution substation feeding the calling customer and the operator can see whether the substation is supplied or unsupplied because of an outage in the MV-network. Further, the operator can choose the distribution substation and switch to the presentation of the low voltage network where the exact location of the customer is shown. The operator can study the detailed customer information (e.g. the annual demand, fuses), location and size of the feeding fuses and switches along the LV-feeder, and the protection coordination of the LV-network. The map drawing of the desired LV-network can be printed out to the paper quickly and flexibly. The paper copy including some text information can be given to the field crew. The operator can also study the annual outage values of a calling customer or make the outage report based on the call. The dialog box of the outage report is partly automatically filled in based on the information of the calling customer. The report can be printed out to the paper or stored to the database to be used as a basis in making the final report of a low voltage network fault.

6.5.11 Switching planning

In the switching planning for maintenance outages (required, for example, in the scheduled maintenance of a primary transformer or a change of cable) the principles are mainly the same as in restoration in fault situations. The planning can be interactive or independent. The idea of interactive planning is to give relevant information on the alternatives and the planned network configuration is checked using accurate calculations based on load forecasts. After a successful planning process the system generates the switching sequence. The plans can, for example, be generated a day before the maintenance. In the DMS the generated plans can be saved and retrieved for execution. In the LAN environment the planning and operation can be located in different places.

In the implementation phase the plan is executed step-by-step in the control center. During the execution the planned switching operations are associated with accurate timestamps. Remote control operations are stamped automatically and manual operations are updated to the plan according to the information from the field crew.

Once the maintenance is finished, the DMS assists in generating the required outage report. The reporting includes an individual report of the specific outage and summing of annual outage count and duration applying to MV/LV substation and customer. The calculation of outage duration is based on the timestamps of the switching operations.

Advance notices to customers of the coming power cut are of great importance dealing with the scheduled outages. Notice can be given by letter or newspaper announcement. The DMS forms the list of customers for notification.

The DMS provides two planning models for load shedding, one for feeders and the other for all remote switches. In both models the idea is to seek a switching sequence which accomplishes the required load shedding (10 %, for example) with minimum outage costs to the customers.

6.5.12 Optimization of network operation

In optimizing the network operation the objective is to minimize the total costs of network operation subject to operating constraints. Possible measures are changing the open points of the network, controlling the voltage by on-load tap changers and capacitors. The heuristic optimization is based on the real-time or forecasted network calculations and can be interactive or independent. The independent optimization can be activated automatically, for example, once an hour.

Reconfiguration

There are several alternatives to carry out the network reconfiguration functions. The objective can be the loss reduction or the reliability improvement. The loss reduction method can be applied using either all the switches or only the remote controlled switches and the reliability improvement method only by the remote controlled switches. The final result is the achieved numeric improvement and the switching sequence. In normal operation it is reasonable to make only remote controlled switching changes. During peak power also the manual switchings for loss reduction would be beneficial, because the marginal cost of energy is very high. A reasonable principle could be that loss reduction is of primary importance during heavy loads and with high marginal costs, but at other times the network configuration aims to minimize the expected outage costs.

Loss Reduction Method: In the loss reduction method the possible reconfiguration operations are analyzed by calculating a linear approximation of the change in losses. The switch pair which will cause the largest loss reduction is then chosen and the switching states are then changed in the network model and the network calculations are carried out. Using the results of the network calculations, the loss reduction can be ensured and a new reconfiguration round can be processed. The reconfiguration is continued for as long as loss reduction can be achieved or a fixed number (10, for example) of unsuccessful switch pairs have been tried.

Reliability Improvement Method: The reliability improvement model for reconfiguration has been developed only for remote switches. In the method the open points of the initial state of the network are analyzed. For each remote controlled open point a heuristic reliability improvement index is determined. The index repesents the change in expected outage costs if one remote controlled zone is transferred from one feeder (F1) to another (F2). After changing the switching state of the switch pair with the largest reduction in EOC the new network state is analyzed. The process continues until no further reliability improvement can be achieved or a fixed number of unsuccessful switch pairs has been tried.

Comparative study applying genetic algorithm technique: During the last year of the study, considerable efforts were made in the development of a genetic algorithm (GA) for loss reduction. In order to obtain practical and comparative results the GA was integrated into the DMS. The integration is based on interface functions, providing coding and decoding. The fitness function is fully embedded in the DMS and all of the genetic operations are independent of the other DMS codes.

The GA developed was tested using the data from the pilot company. In most of the studies in which GA technique has been applied for reconfiguration tasks the test networks have been rather small. In the present study one of the basic ideas was to apply GA in a real scale network. This requirement was fairly well fulfilled, which is a very important contribution in the domain and proves the applicability of GA technique to a practical reconfiguration task. In spite of the successful application of GA technique it should be noted that the long response times are not well suited to the operational application. Thus the GA is appropriate to planning purposes and generally in searching for a global optimum

Optimal voltage control

Since the estimated and forecasted loads in the DMS include load-voltage dependences the user can simulate a change in selected busbar voltage. In the case of peak clipping the DMS displays the reduction in the total load of the primary substation and the voltage level in the network after the voltage reduction. In the other case the DMS searches the highest busbar voltage causing no overvoltage to any customer and displays the change in total load and losses.

Each time the voltage levels are shown on screen an approximative analysis of voltage level in each low voltage network is performed. The analysis utilizes the monitoring calculations of the LV-networks and load models of the specific hour. Further state estimation results of the MV-network are used. The voltage level in the MV-network and the real-time demand of the distribution substation are used to calculate the lowest voltage level at customers. As a result, each distribution substation where the lowest voltage is less than 90% of the nominal voltage is shown on screen in red, the general alarm color of the DMS.

The voltage control methods can be extended to take into account the duration of voltage reduction, which affects the demand since the load tends to reach its previous value. Thus it is possible to plan the right timing for voltage reduction for peak clipping.

6.5.13 Management of reactive power in subtransmission networks

The national grid company has sold most of its normally radially operated branches of the 110 kV network to local grid companies. These branches feed some primary substations and are considered to be a part of regional electricity distribution and not a part of the national grid. The regional companies are now responsible for the operation and management of these networks, but they do not have good tools for this. For example, the existing SCADA systems cannot monitor the loads of these branches. The new tariffs for reactive power are, in particular, imposing new requirements for reactive power management. Thus the first application of the DMS dealing with subtransmission networks forecasts the demand and generation of reactive power and permits the control of reactive power generation with capacitors and generators to keep the reactive power in its limits and to avoid the very high costs of feeding reactive power to the national grid. Benefits from forecasting and control of reactive power come from savings in reactive power fees and network losses as well as from the expansion of transfer capacity of subtransmission lines.

6.6 IMPLEMENTATION

The DMS is a Windows NT -program implemented by object-oriented Visual C++. The interactive graphical user-interface has been developed by the tools of Visual C++ using Microsoft Foundation Classes (MFC) libraries. The pilot implementation consists of the DMS, S.P.I.D.E.R. MicroSCADA by ABB Transmit Oy, and AM/FM/GIS by Versoft Oy. The data interfaces has been developed in co-operation with ABB Transmit Oy and Versoft Oy.

The research version of the DMS was revised as a commercial product of Versoft Oy named Open++ Opera. It has now been implemented in several distribution companies (e.g. Satapirkan Sähkö Oy, Hämeenlinnan Energia Oy). At present the international commercialization process continues in ABB Transmit Co.

6.6.1 Koillis-Satakunnan Sähkö Oy - the pilot implementation

All the developed applications has been tested and almost all are in everyday use in the real control center of the pilot utility, Koillis-Satakunnan Sähkö Oy. The pilot utility is a typical Finnish distribution utility with about 13 000 customers. The total delivery of energy by the utility is about 150 GWh and the peak power about 35 MW. Most of the distribution is in rural areas with over 1 400 km of medium voltage lines, about 1 000 distribution substations (20/0.4 kV) and about 600 network disconnectors, of which 75 are remote controlled. Relating to the overall automation system and to the computer systems the utility is very advanced, which has made it very suitable for our development purposes. For example, all the MV-feeder relays are microprocessor based with fault current registration ability.

In the control center of Koillis-Satakunnan Sähkö Oy the DMS runs in a PC having a 166 MHz Pentium processor and 32 Mb RAM. The company has a Windows NT based network database system (AM/FM/GIS) with open relational database of Versoft Oy, a UNIX-based S.P.I.D.E.R MicroSCADA of ABB Transmit Oy running in a PC, a UNIX-based customer database of Siemens-Nixdorf Oy, and a telephone answering machine system of Merlin Systems Oy.

All the computer systems of the pilot utility are integrated using a local area network (LAN) and TCP/IP protocol for the real-time communication (Fig. 28). The LAN has been divided into segments (i.e. subnetworks). The server computer also acts as a router between segments. The computer systems of the control center form one separate segment. This means that the control center segment works alone without any disturbances even if another part of the LAN goes down. The communication between the SCADA and the DMS is real-time and full-duplex. The DMS can read the network and customer data through the LAN for its own network model. The telephone answering machine and the DMS communicate using the LAN, too. The DMS can be run anywhere in the LAN. The primary information needed is obtained from the server where the DMS of the control center stores the needed data (e.g. real-time switching state, fault information, fault reports). The DMS outside the control center is applicable only for monitoring purposes; the switching actions are done in the control center.

6.6.2 Other case installations

Satapirkan Sähkö Oy is a big distribution utility consortium consisting of nine regional member utilities having, for example, 101964 customers, a 6505 km^2 distribution area, and 6028 distribution substations. The utility has concentrated most of the operation of its distribution networks on one control center. Also the DMS in control center covers all the networks of member utilities. The DMS utilizes a wide area network (WAN) connecting member utilities, their databases and their local area networks. The SCADA system of the utility is the S.P.I.D.E.R MicroSCADA running in Windows NT operating system. The case of Hämeenlinnan Energia Oy is a good example of openness, since vendors of both the AM/FM/GIS and the SCADA are different than in previous cases. The UNIX-based AM/FM/GIS has been delivered by Tietosavo Oy. The Nematic SCADA system of Netcontrol Oy is working in Windows NT operating system.

6.7 THE BENEFITS OF THE SYSTEM

The annual mean outage time of a distribution substation per fault at Koillis-Satakunnan Sähkö Oy has decreased considerably in the past eight years, as seen in Fig. 6. At the same time the organization of the field crew during a fault situation has been changed so that only one working group is a duty instead of the previous practice of two groups. The remote controlled disconnectors, the µP-based relays, and the DMS have been the reasons for the reduced outage times. Together these three things mean more than all three alone. At Koillis-Satakunnan Sähkö Oy the intensive development of distribution automation began with the acquisition of an RMX-based SCADA in 1988. Remote controlled disconnectors and µP-based relays were being installed, so that by spring 1991 all the MV-feeders were provided with µP-based relays and by the end of 1991 there were 75 remote controlled disconnectors. The first version of the fault location application was implemented at the beginning of 1991. So far the fault location application has been used in over 200 faults. Most of the faults have been located with an accuracy of some hundred meters, while the distance of a fault from the feeding point has been from a few to tens of kilometers.

The experiences of using optimization modules for network reconfiguration of the pilot company's network show that more than 10 % loss reduction can be achieved. The overall objective of the network operation is to minimize the total costs (losses and outage costs) subject to technical constraints. The use of the intelligent application functions of the DMS improves the fulfilment of the objective. The use of the functions in faulted state reduces the outage costs, the use of the optimization function reduces losses and the constraint violations are detected by the system. The benefits of the application functions are summarized in Table 4.

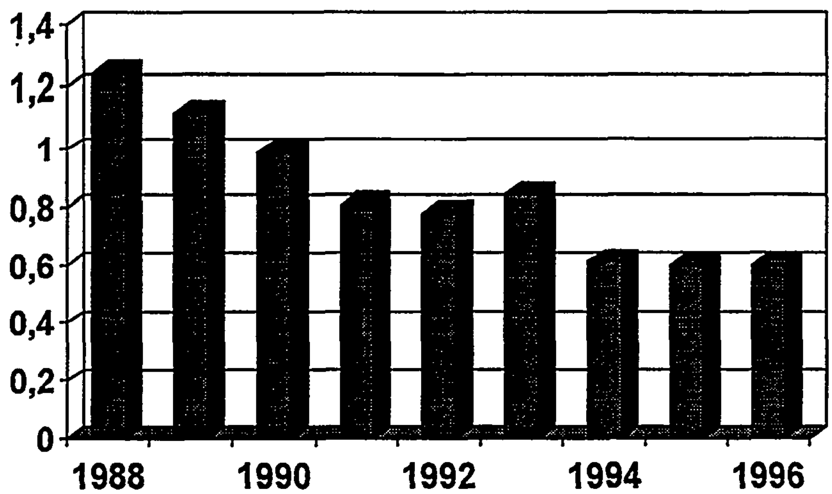

Fig. 28. The mean outage time of a customer per fault at Koillis-Satakunnan Sähkö Oy.

Table 4. The benefits of the functions of the DMS.

	voltage level	number of outages	outage costs	working costs	cost of losses	investments
network monitoring	X	(X)			(X)	X
optimization	X	(X)	(X)		X	X
maintenance outage planning	(X)	(X)	X	X		
event analysis & fault location		X	X	X		
fault isolation & restoration planning	(X)	(X)	X	X		X

X obvious benefit
(X) indirect benefit

7 ADDITIONAL FUNCTIONS OF REMOTELY READ kWh-METERS

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7.1 INTRODUCTION

In this chapter the possibilities to include new applications into remotely read smart kWh-meters are considered. New electronic meters can measure various electric quantities and have some extra calculating capacity. So they can be used to provide functions that distribution automation and the customer need and thus share the costs. Some applications like monitoring the state of the distribution network or locating faults are only for the utility, but many applications also need an interface to the customer or his automation system. Among those are monitoring the quality of electricity, estimating load curves, applying dynamic tariffs and selling electricity and accounting. As a special item, the continuous monitoring of the quality of electricity is discussed. This includes voltage levels, total distortion, asymmetry and so on. If such a kWh-meter indicates quality problems we can go there with a portable quality meter that is suitable for the case and inspect the situation. The poor quality can be detected before it causes harm to equipment owned by the customers or the power distribution company. This paper also presents a prototype of such a quality monitoring kWh-meter.

Dynamic tariffs and free electricity markets require two way communication with the utility and the customer and measurement of the time variations of the energy consumption. The customer or his energy management system must receive the energy prices from the utility and calculate the energy costs and decide energy consumption control actions. We compare some alternative ways to meet these customer interface requirements.

Remote reading of kWh-meters requires a certain investment in meters and their data communication with the utility. Because smart meters can have some additional memory and calculating capacity and are capable of measuring various electric quantities, it is possible to share the costs with other applications that use the same hardware and data communication channels. The costs of remote reading have been approximated by Alexander in the United States /1/ and Støa and others in Norway /47/. They both have also considered various other applications that share the communication channels.

In this chapter, the following new applications for remotely read smart kWh-meters are discussed:

- monitoring the state of distribution networks
- continuous monitoring of the quality of electricity
- locating faults
- measuring load curves
- load control using dynamic tariffs or direct control
- supporting electricity sales activities
- remote reading of other flow and energy measurements
- customer services.

New applications require new capabilities from the meters and their reading systems. Chapter 7.3 presents a modification of an existing smart kWh-meter. This new version is designed to monitor the power quality also. A more detailed description of the methods and field test results is in Ref. /20/. A new meter reading system for such multi application meters is described in Ref. /41/. The requirements of future smart billing meters for measuring power quality and different active and reactive powers are discussed in Ref. /19/.

We emphasize measurements of power quality and reactive power more than the other potentially equally important application areas. Nevertheless the power quality, including the harmonic content, is an increasing problem /8,10/.

7.2 ADDITIONAL APPLICATIONS

7.2.1 Monitoring the state of the distribution network

Remotely read kWh-meters can monitor the state of the distribution networks. This supports the estimation, prediction and further optimization of network loading. Here the objective is to minimize distribution losses by choosing voltage levels, reactive power compensation and connections of loads to alternative transformers or other network components. It is important that we can get the situation at the same time from all the meters and so reduce the uncertainties to the minimum.

7.2.2 Locating faults

We think that at the present time the main problem, when locating faults with remotely read meters, is the time required to poll meters via the public telephone network. In the future, telephone companies may provide polling and alarm handling services that solve this problem. The meter should be able to communicate data during power interruptions also. If the meter has an adequate sampling rate, calculation and memory capacity, even disturbance recording is possible.

7.2.3 Monitoring the quality of electricity

The quality of electricity is becoming more important than before. This is because the number of power distorting devices is increasing and at the same time many new appliances require a certain power quality.

With adequate power quality we mean that the following quantities are within accepted limits:
- voltage levels (variations)
- voltage excursions, voltage sags (dips) and swells (peaks), rapid voltage changes
- voltage fluctuations, flicker
- transient and temporary over voltages
- voltage interruptions
- harmonic frequencies and intermediate frequencies
- voltage unbalance (asymmetry)
- direct current or voltage component

7.2.4 Measuring load curves

The customer load variation curves are crucial for the utility. They are needed when the utility predicts its energy and power demand in order to be able to plan the purchase of electricity and to plan investments in resources like electricity distribution networks and power plants. So they are important as background information for both daily operation and short and long term planning.

Free electricity trade will increase the importance of the load variation curves. Each electricity sales company estimates its costs for meeting the customer consumption and plans alternative ways to compete against other sales companies. It plans tariff offers and methods to modify the load curve so that it can be met with less costs. It is in the customer's interest that his load curves are available to several electricity sales companies and to himself too. There are several alternatives to arrange this. It can be either one utility, many utilities, the customer or a separate measurement service company that collects consumption data of a given customer and gives it to the other parties involved. The customer may want to have its own tool for optimizing its operation against tariffs and thus be able to compare them.

The recording of the variations of power per hour (or shorter period) is a standard feature of new electronic kWh-meters. The reading is normally done by the utility but the customer can also read this data if he has a suitable program and permission.

7.2.5 Applying dynamic tariffs

For dynamic pricing the utility should be able to change tariff price parameters and normal schedule for time variable prices and also to set temporary low or high price periods. It should also be possible to give advance information of the temporary changes and record when the notification and change will come.

It is often important for the customer to get to know the temporary price changes some time before the new price becomes active. He may be able to prepare for example by storing energy or postponing the start of batch processing.

The customer needs equipment or systems that can automatically react to dynamic prices. Very high prices are rare but require proper response at short notice. It is not enough that the meter gets the price changes. There must also be some control action. So the customer's automation system or equivalent should often get the prices too.

7.2.6 Remote reading other flow and energy meters

If the meter has pulse inputs, it can be connected directly to other consumption meters for remote reading via the meter. Measurements of water, gas and district heat are typical examples.

7.2.7 Selling electricity and accounting

Some automation may be needed to support temporary purchase and selling of electricity. It could respond for example to offers to update contract parameters. Better user interface than what can be reasonably obtained from the meter may be necessary. The meter should be able to utilize dynamic tariffs and it should be possible for the customer to check how different components of his electricity bill are developing. It is also important that the automation system of the user gets the power consumption readings in real time.

Who gives the load curves to a nonlocal electricity sales company so that it can estimate its costs for meeting the demand? Should every sales company also read the meters of other companies and have all possible reading programs for that purpose? Hopefully not. Should it be the customers' or the local distribution company or both that give the sales companies the load curves? The answer to these questions may require some mutual agreements on procedures and data communication.

7.2.8 Providing energy consumption data to the consumer

Many applications also need an interface to the customer or his automation system. The customer may want to know his consumption in real time and also analyze his load curves in order to be able to control the consumption and costs.

7.2.9 Overview of the applications

To what extent is it practical to include the applications described above in the meter or reading system? It is better to implement many user related functions outside the meter. But even then they require some properties from the meters such as reasonable input and output capabilities. An example is shown in Figure 29. And at least they should share the same communication channels in order to reduce the costs.

7.3 PROTOTYPE OF A QUALITY MONITORING kWh-METER

7.3.1 Prototype meters

With the prototype we want to find out what continuous quality monitoring properties are needed by testing a reasonable number of meters in a real environment. At the same time these meters are normal registering kWh-meters. The prototype is based on a smart electronic kWh-meter.

The plan is that the field tests of the prototype meters will be completed near the end of 1994. Then the results will be analyzed and the requirements for the next meter generation specified. In the prototype test we want to collect as much information as possible. In real operation we want to filter out the essential information and forget the rest after a short storage period. But first we must determine, with the prototype project, what is needed in reality.

7.3.2 Voltage levels

In sparsely populated areas the customer voltage levels limit the possibilities to add new loads to the network. Sometimes this can also happen in cities, for example during faults. Reducing voltage levels is also sometimes used as a means to reduce consumption during periods of high demand. But the voltages must be kept within acceptable limits. The aging or operation of user equipment may suffer if voltage is too high or low. So it is important to be able to register voltage levels and monitor them. The metering of voltage levels is needed near the locations were they are known to be highest or lowest. The voltage levels at other points of the network can then be estimated by combining network models and measurements.

The prototype has somewhat more detailed monitoring of the voltage levels than the original meter.

7.3.3 Voltage excursions

Voltage swells and sags are registered in the prototype. The utilities want to be able to check if there really was a voltage excursion and what it was like if a customer complains about some problems with his appliances that may be related to the power feed.

The measurement of short (duration well under 1 second) voltage excursions is not included in this prototype. It is possible to a certain extent and it is included in Figure 30, but we think that it is better to connect a separate detector to an input of the meter when we are interested in fast transients.

7.3.4 Total distortion

The harmonic content in the networks increases together with the amount of electronic equipment and appliances generating them, like inverters, rectifiers, adjustable speed motor drives, electronic ballasts, personal computers and fluorescent lamps. The harmonics are often increased by a resonance. They cause losses and heating in the power distribution network or devices connected to it, especially in motors, transformers and capacitors. The harmonics disrupt the operation of computers and other sensitive customer or network equipment. The effects of harmonics on equipment are discussed in detail in Reference /9/.

In this prototype we want a very general figure that tells about the overall view of the voltage wave form and frequency content. So we define the total distortion so that it includes all other frequencies except the fundamental frequency of the network. It includes total harmonic distortion, intermediate frequencies and frequencies under the fundamental frequency. All normally interesting harmonic components are included, because the upper frequency limit is determined by the virtual sample rate of the meter or possible prefilters.

We think it is better to have the intermediate frequencies included. We suppose that the harmful effect is seldom very different between harmonics and nonharmonics although certain harmonic frequencies cause counter rotating fields in motors and some others currents in the neutral conductor. Otherwise the heating effects are the same and the power of intermediate frequencies is almost always very much smaller compared to the harmonic frequencies.

There are, however, reasons why the total voltage distortion does not tell enough. One is that it does not tell the direction of the power of different harmonics. That would help in locating the polluter. Another reason is that the heating of especially the transformers, depends strongly on the frequency; it is roughly proportional to the square of the frequency and square of the current. In principle it is easy to calculate total distortions on some frequency bands. But here we want to keep the meter simple and low cost. More detailed analysis can be made with a portable harmonics meter that is too expensive for continuous monitoring.

Figure 30 shows a principle for calculating the total distortion. It is based on a discrete state observer where the state represents the rotating phasor of the input quantity. This method can also be applied when the sampling rate is rather low. Also higher frequencies will come through to the total distortion via the aliasing effect, except a few special frequencies that alias on the fundamental frequency. The highest frequency is determined by the prefilter before the sampling. However, the lower the sampling rate, the slower the response or more uncertainty in the result, because we must assume more of the stationarity of the signal. But still, we can quite correctly measure total distortion that includes frequencies much above the sampling frequency.

But there is a problem with the slow sampling rate. It is impossible to distinguish, after the sampling, some aliased frequency from the frequency on which it has aliased. This is not a problem with the total distortion, if the sampling rate is carefully chosen. But that makes it impossible to divide the total distortion into components roughly above and below some corner frequency. With high a sampling rate and the same method, that would be very easy.

7.3.5 Asymmetry (Unbalance in three phase network)

Voltage unbalance between the three phases causes extra heating in three phase motors. It also indicates uneconomical network use and certain faults in the network.

The measurement of voltage asymmetry is included in the prototype. The symmetric components (positive, negative and zero sequence voltages) are calculated from the estimated voltage phasors directly according to the definition.

7.3.6 Direct voltage component

Direct current is harmful in alternating current networks. It saturates transformers and increases losses. That is why d.c. voltage is measured in the prototype meters.

7.3.7 Results

The new methods were tested first in laboratories and after some improvements in field tests. This happened in spring 1995. In the field tests several new meters and reference meters were connected to the low voltage feeders of three power substations. All one second effective values were collected and most of that data analysed. In the one second values possible problems in meter performance can better be detected than in the 10 minute values that are typically needed in power quality monitoring. In those field tests the meters worked fine. Figures 31 and 32 show an example.

7.3.8 Meter reading system

A new remote reading system for kWh-meters has been developed because new requirements have emerged. The amount of data to be collected and processed is increasing with the number of remote readable meters. Data from the meter reading system must be accessible for invoicing and energy management systems in an easy and standardized way. Deregulation of the energy market brings new players that need energy consumption measurement data. New applications like monitoring the power quality and network state are included in the new kWh-meters and their reading system. The reliability and confidentiality of the measurement data should not be violated. The new remote reading and data management system for kwh meters with power quality monitoring is described in /41/. The structure of the system is shown in Figure 33.

7.4 CUSTOMER INTERFACE

A display of the energy consumption is not enough as an interface to the customer and his systems. If the customer has any kind of automation system, he certainly wants to get the power consumption to that system from the meter and usually in real time. Then he can better see and analyze the effect of different actions on his energy consumption.

Especially in free electricity trade, a load curve of the customer is needed for the comparison of the costs of different tariffs and the choice of the best for this particular case. The load curve can be calculated by the customer's own system or the utility can give it when asked. The utility may also make the comparisons for the customer but then the future plans of the customer should be known.

Utilities use load control in order to reduce power acquisition or transmission costs by levelling consumption peaks. Of course the customer should get some compensation for this. Basically there are two different methods for doing it, direct load control and control by dynamic tariffs. The advantage of dynamic tariffs is, that it is the customer, who decides when to restrict the consumption and when to pay the higher costs. This is important, because the power needs of different customers are very different and often changing, for example according to their situation in production and markets. The problem with the dynamic tariffs is, that the utility cannot be sure how much an increase in the price will reduce the consumption. So both direct control and control by prices are needed, preferably in a balanced mix.

It is an advantage if the meter supports both methods of load control. But the load control action should usually be performed by the automation system of the consumer, if it exists. Manual control is just more expensive and unreliable. The potential for load control greatly increases if the customer systems have enough time to prepare for price changes. This advance information from the utility need not come via the meter, but it should be possible to use the same two way communication channels to the utility as for remote reading. The actual control and price change signals are received from a distribution line carrier broadcast. So the customers get the signals quickly and simultaneously. Another alternative is to send the control messages in advance via the two way communication channel. Then we have to trust the synchronization of the clocks. This alternative may become realistic as the telephone companies start to provide broadcast and other services in their networks.

Some users may even want to check the power quality when they suspect that it may have caused some problem. But then there is the danger that anything that occurred at the same time as a power quality problem is claimed to be caused by it. Maybe it is better during the learning period that the user tells the time when he suspects problems and the utility then shows the quality at that time.

Two way communicating smart kWh-meters are more expensive compared to the traditional kWh-meter. But the costs per measuring point can be greatly reduced by multipoint measurement. It is a system, where one smart meter meters several points. For example all consumers connected to the same distribution board can be measured by one meter. Mittrix Oy has also made such pilot systems. The customer interface requirements described above can also be applied to multipoint measurement without excessive extra costs or difficulties.

7.5 FUTURE VIEWS

If there are many smart meters, it is possible to collect huge amounts of data. Then the problem is, how to find out the relevant information from it. This requires certain intelligence and flexibility from both the meters and the meter reading systems. The meter should be able to compress the data of normal conditions into just a few figures which says that everything is all right. But when something special happens or some other system needs the measurement data, it should be available. Users and other systems should get the data they need with simple search commands without manually browsing irrelevant masses of data.

Safety and security in the meter data communication cannot be made perfect with reasonable costs. The meter is easier to protect by using restricted permission rights that determine who may read what from the meter and who may set the parameters. In the data communication it would be possible to use methods for encryption or checking the origin and integrity of the message. But there the requirements for computation power tend to increase together with the computation power available for breaking these methods.

For the electricity trade, the power utilities need registering or real time energy measurements of the customer's consumption. The customers control their loads based on the real time readings from the registering meters, because they are available and help them to avoid the costs of not keeping to the planned power.

There are several possibilities for future work with the prototype meters:

- Improve the preprocessing and compression of the data in the meter.

- Improve the availability of measurement data for other systems in the utility by further developing the meter reading system.

- Power quality:
  - monitoring from three to five of the most common harmonic frequencies
  - monitoring the direction of those harmonics

- Use the experience of the pilot systems to the development of the meters.

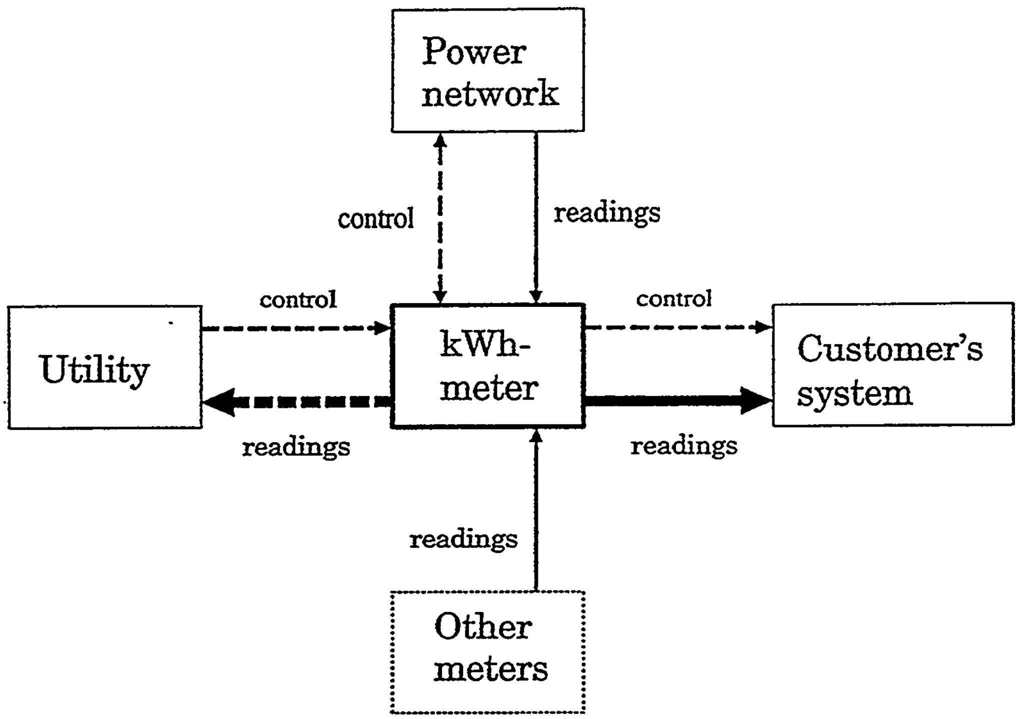
- Develop data models for data communication with the meters.

- Improve the security of the data communication.

The cost of the data processing power that can be put in the meters is decreasing. We are gathering practical experience and knowledge on how to utilize it.

7.6 CONCLUSIONS

There are many applications that can share the data communication costs with remote meter reading. However they demand certain requirements of the meter. But most of these requirements can be met with a smart energy meter. It is even possible to detect many important power quality problems in the network with a smart energy meter even with a relatively low sampling rate.



Two way data communication with the utility for
load control and
other applications

Real time interface to the automation system of the customer

Pulse and digital IO for other measurements and simple control

Fig. 29. Interfaces of the kWh-meter.

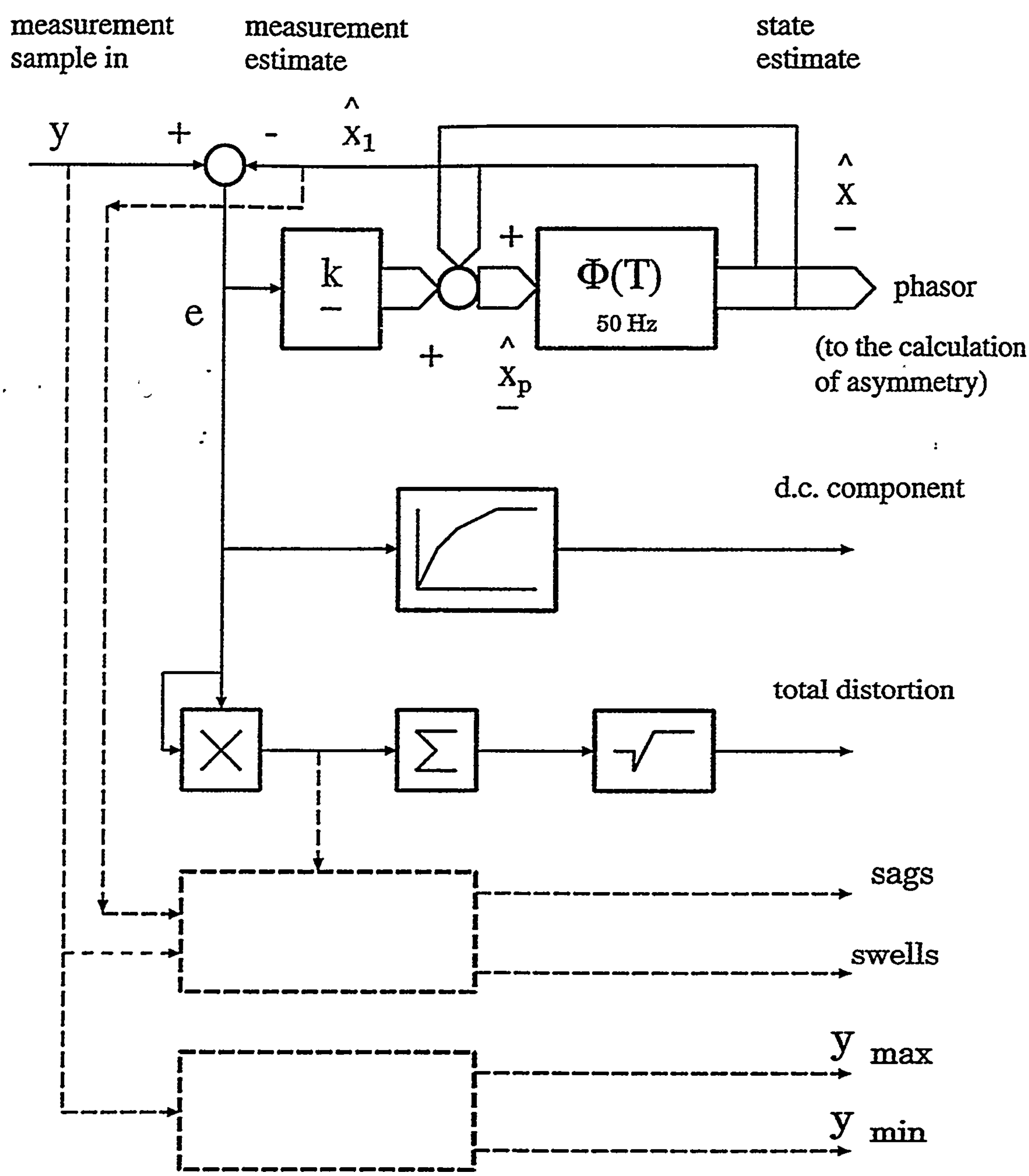


Fig. 30. A method for quality monitoring with a kWh meter when having a sparse sampling.

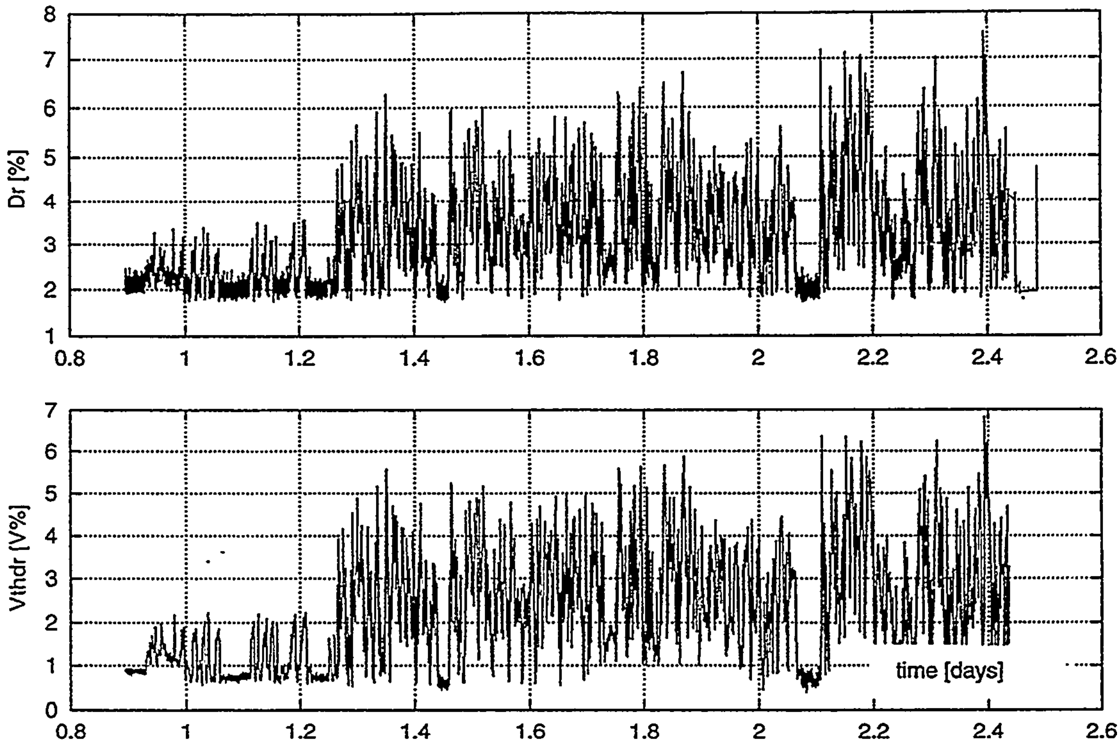


Fig. 31. Distortion measured by the new meter (top) and a reference meter (below), all one second values of the measuring period are shown.

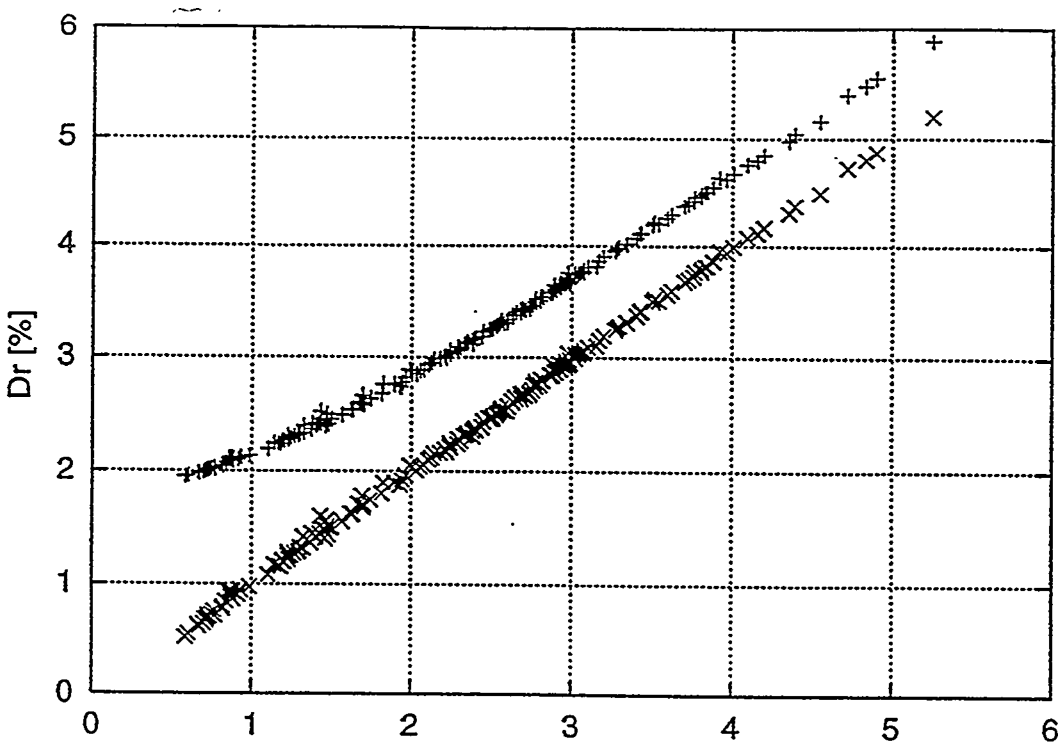


Fig. 32. Distortion measured by a reference meter and the new kWh-meter, + raw, x when a correction function is applied, ten minute values.

CLIENT/SERVER VERSION OF THE METER READING SYSTEM

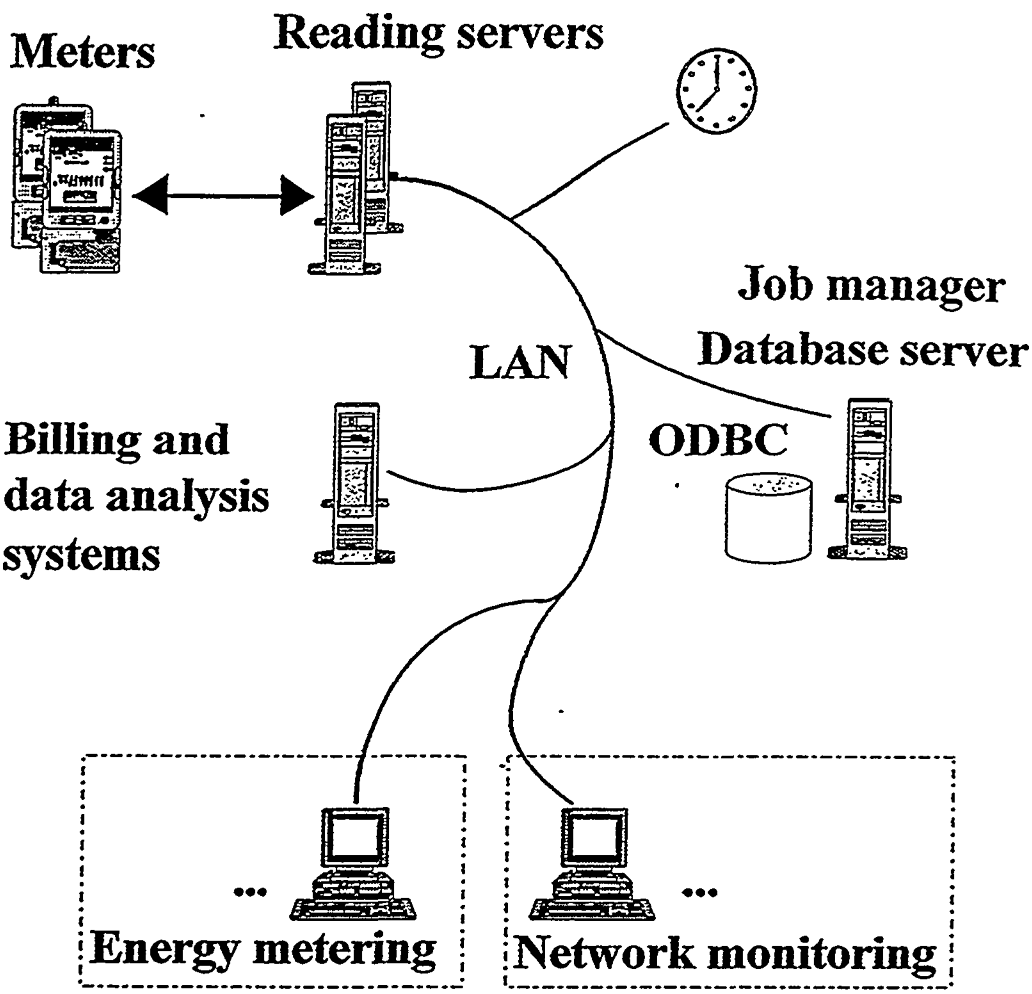


Fig. 33. Main structure of the new remote reading system at Helsinki Energy.

8 WIRELESS COMMUNICATION TECHNOLOGIES IN DISTRIBUTION AUTOMATION

Juha Takala, VTT Energy

The project is started in mid 1995 and will be finished in the first quarter of 1997. The project examines four different wireless communication technologies:

- GSM short message service
- NMT data calls
- packet radio network
- Autonet (Actionet) status message service

The targets for communication include:

- energy measurement, especially in the de-regulated electricity market
- secondary sub-station control
- fault indicators

The research concentrates on the usability of different communication technologies for different purposes. Data about response times, reliability, error rates, retry times, communication delays, costs etc. will be collected about each communication technology and comparative results will be analysed. Some field experiments and demonstrations will be made in energy measurement and distribution network remote control.

The project is divided into four tasks. Each task is described briefly.

8.1 GSM SHORT MESSAGE SERVICE IN REMOTE METER READING

The main target of this task was to find out if GSM Short Message Service is suitable for remote meter reading. The partners in this task are:

- Enermet Oy, a meter manufacturer, implements the interface between the kWh-meter and GSM phone
- Nokia Mobile Phones (NMP), a mobile phone manufacturer, provides data cards and accumulator expanders for easy interface between mobile phone and the kWh meter
- Radiolinja Oy, a telecommunication operator, provides access to the SMSC and short message traffic
- Espoon Sähkö Oy, a distribution utility, provides some customers for testing purposes
- VTT Information Technology makes the SMSC communication software

The principle of the operation is shown in Figure 34.

Short Messages are built into the kWh meter (or in the interface unit), and sent through the GSM network into the Short Message Service Centre (SMSC). The interface between the kWh-meter and GSM telephone is a Data Card Expander in the pilot, but should be replaced by Cellular Ware technology (the latter is more economical in larger quantities).

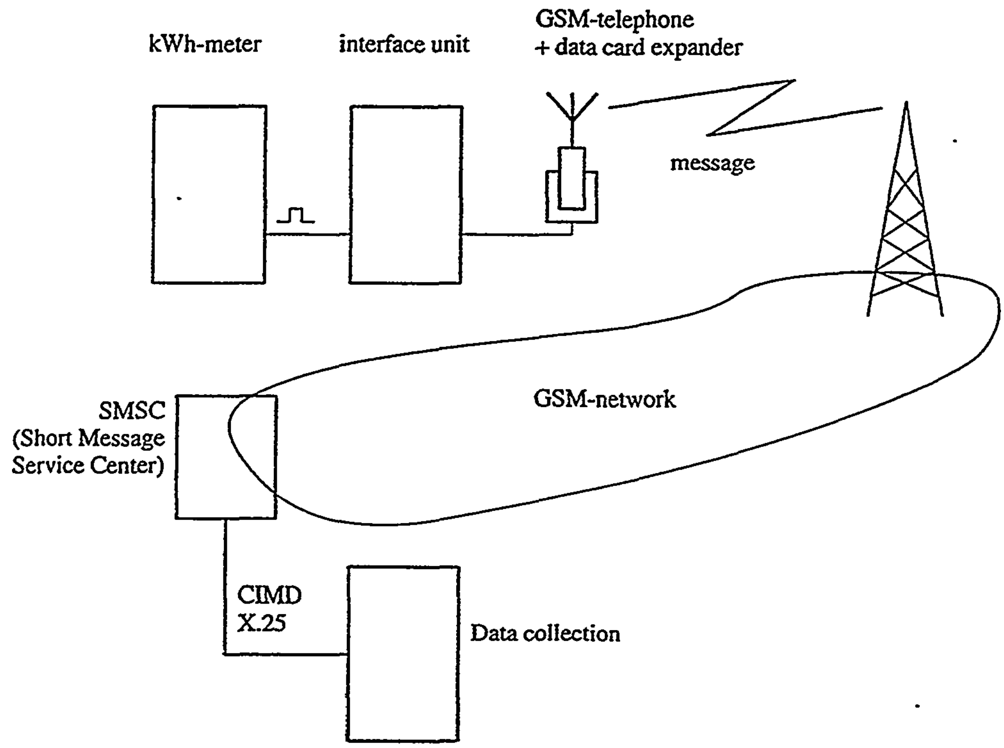


Fig. 34. Principle of using GSM SMS (Short Message Service) in remote meter reading.

The meter reading happens in two independent stages:

- Messages from different kWh-meters arrive to the SMSC; several meters may send at the same time, and the GSM network makes this possible. Each message contains a time stamp and information about its origin and the actual meter readings. Messages are received by SMSC and they get an additional time stamp at the moment of arrival..
- The messages are collected from the SMSC to the central system. The interface to SMSC in this pilot system is X.25. Several messages are collected in one session, quickly, one after another. Time stamps and information of origin will identify each message. The delay between the first and second stage does not matter.

A definition of message contents and structure was done at VTT in co-operation with Enermet Oy. Necessary modifications were made in Enermet Oy's terminal units so that the terminal units were able to communicate with the GSM phone's data card. The software in the terminal units is based mostly on existing products, only absolutely necessary modifications were made for the purpose of the main targets of this project. Field tests were carried out from October 1996 through January 1997.

The message structure that was developed, is designed in such a way that as much autonomous operation as possible is allowed. The spirit of protocol messages from central station to meter is often: "From now on, start sending hourly readings once a day, at 1:30 every night", or: "Starting at time xx, start to operate in such-and-such a way". This principle is designed to save communication costs, because each message costs. The message structure has been designed so that communicating once a day, preferably night time, per each meter, would be the main "operating mode".

When receiving a message from a meter, the central station always checks the time difference between the meter and central station. The variation of message transfer delay is eliminated, and if the times differ, a correction message is sent to the meter. The correction is sent as an offset, so that the variable delay in message transfer time does not affect the accuracy.

Results

There seem to be no known technical limitations that would prevent GSM Short Message Service from being used in remote meter reading:

- The limited size of one GSM Short Message (maximum 160 7-bit characters) is enough to transmit 24 hourly readings.
- The reliability of message transmission was found to be high enough.
- The variable delay in message transmission times does not matter in meter reading or time keeping.

The implementation in the pilot project uncovered some potential problems:

- The power consumption of the GSM phone should be as small as possible by avoiding communication as much as possible. The reason seems to be the re-charging algorithm in the GSM phone that tries to protect the battery against over charging. Stand-by re-charging seems not to be enough to keep the battery charged, if communication is done very often.
- In case of problems in the communication between the meter and GSM-phone, there is no way to reset the GSM-phone from the meter side. The reason for this is probably because the GSM phone was originally designed to be communication equipment for humans.

The indicated problems are not in the Short Message mechanism, but in the mobile phone equipment (hardware). The problems have been reported to the manufacturer, and it is expected that in future versions these will be corrected.

The final decision about using GSM Short Messages in remote meter reading will depend on prices of available mobile phones, interface with the meter, and the costs of messages sent (set by the operator).

8.2 NMT DATA IN REMOTE METER READING

NMT (Nordic Mobile Telephone) is a mobile communication technology, that is quite popular in Nordic (and some other) countries in Europe. It not expected to gain much more popularity, but the NMT network has a somewhat better coverage in Finland than the GSM network at the moment, especially in rural areas. The usability of NMT technology in remote meter reading is studied mainly for this reason.

The partners in this task are:

- Mittrix Oy, a meter manufacturer, implements the interface between the kWh-meter and NMT phone
- Enersoft Oy, a software company, is responsible for the meter reading software, and provides the logging information for this project
- Helsinki Energy, a distribution utility, has the meters and data collection system installed.

The principle of using NMT data calls in remote meter reading is shown in Figure 35.

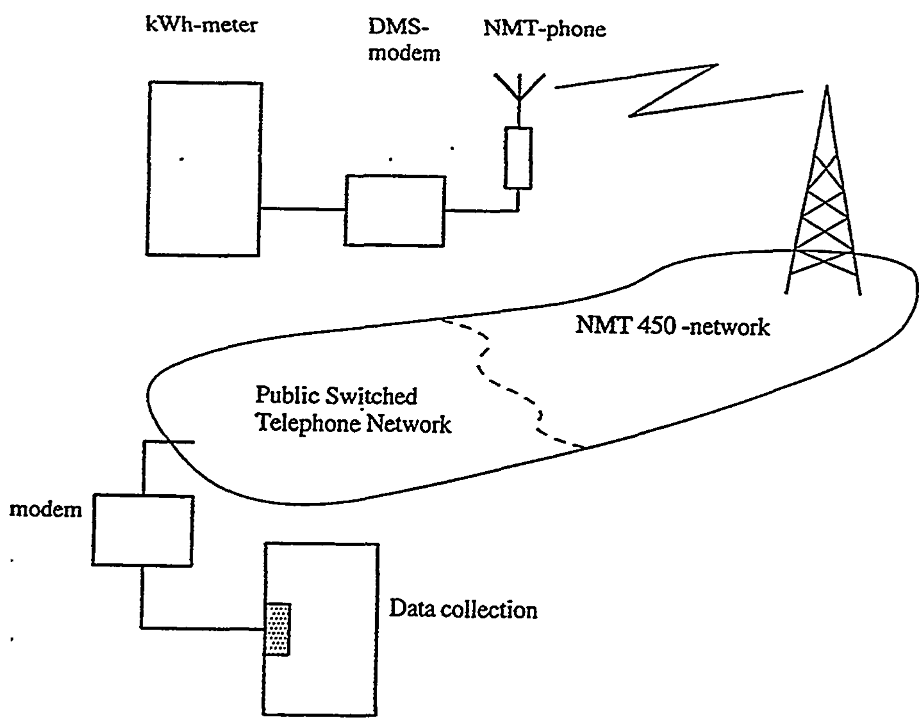


Fig. 35. The principle of using NMT data calls in remote meter reading.

.The meter reading is always initiated by the central station, and at most one meter can be read at any time.

The data collection software at the central station will make log entries containing time stamps of the following events concerning each remote meter:

- start of reading activity
- connection of NMT call established
- disconnection of NMT call
- end of reading activity

This data will be processed to get statistical quantities like averages, maximum and minimum values of connection time, throughput, error rate etc.

Field installation of these devices has been cancelled because of problems with modems at the meter end. It is believed that the problems are in the modem set-up and configuration.

An NMT telephone was connected with a modem into a computer at VTT, and connection set-up times were studied in such a set-up.

8.3 PACKET RADIO NETWORK IN DISTRIBUTION AUTOMATION

The partners in this task are:

- ABB Transmit provides technical support and documentation
- Keski-Suomen Valo Oy, a distribution utility, provides the distribution network where a packet radio network is used.

ABB has developed packet radio technology for distribution automation. The network is made of small power radio nodes, that operate all at the same frequency. The principle is shown in Figure 36. The message propagates in the network in "hops" from one node to another. The ABB Paknet operates in such a way, that the communication is always initiated by the central node, and the route of the message is contained in each message (other principles are also possible). Route management is done in the Paknet Control Computer (PCC).

In this project, PCC log files are generated that contain time stamps of message traffic. This information is processed to get statistical quantities like means, deviations, minimum and maximum values of turnaround times, retry times, etc. Also the routing will be varied to get information about how the hop length and hop count affect those quantities.

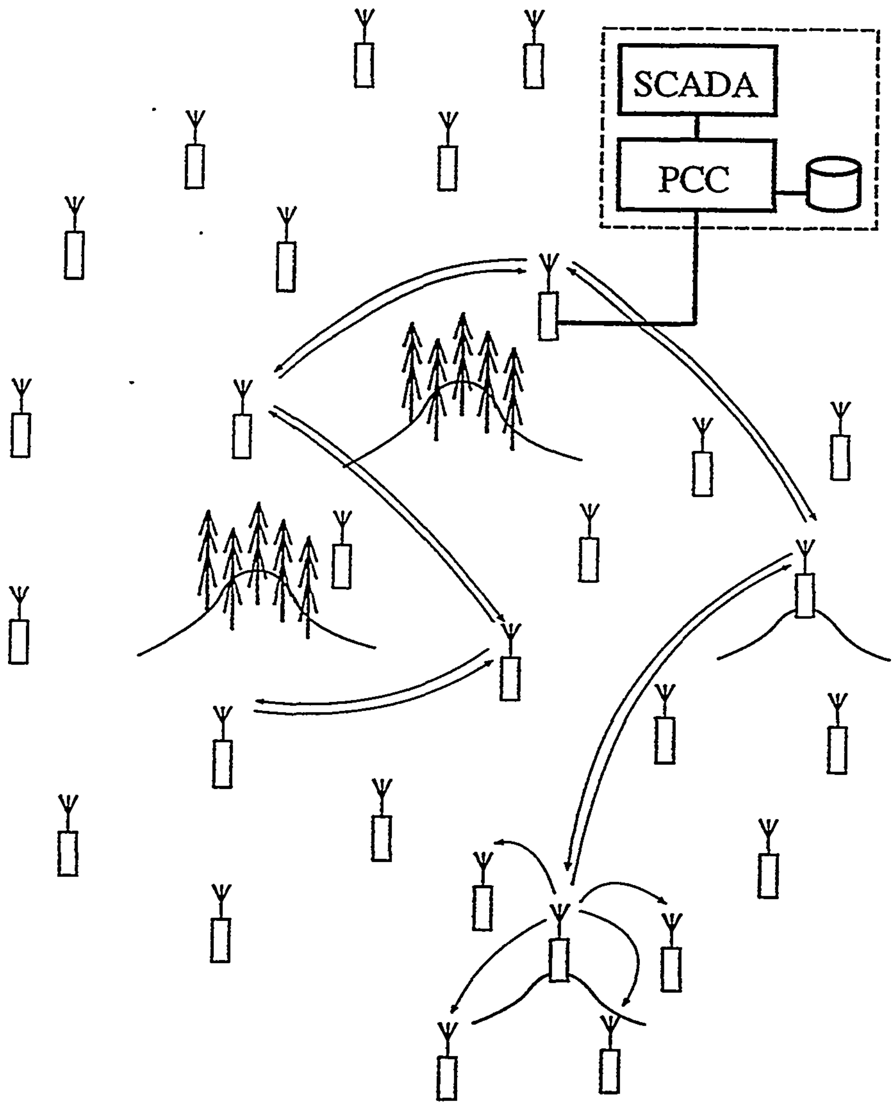


Fig. 36. Packet radio network in distribution automation.

Information about message transmission times may be calculated with some accuracy from the technical data, but measurements made in the live network are the final proof. To make this measurement, the routing of the radio network was temporarily modified so that a long chain of radio nodes was built. Short test messages were sent to each node in the network every five minutes, for a couple of hours, and the log file creation was activated. Afterwards the time stamps from the log file were collected, sorted by node, and the times calculated and tabulated. The results are shown in Figure 37.

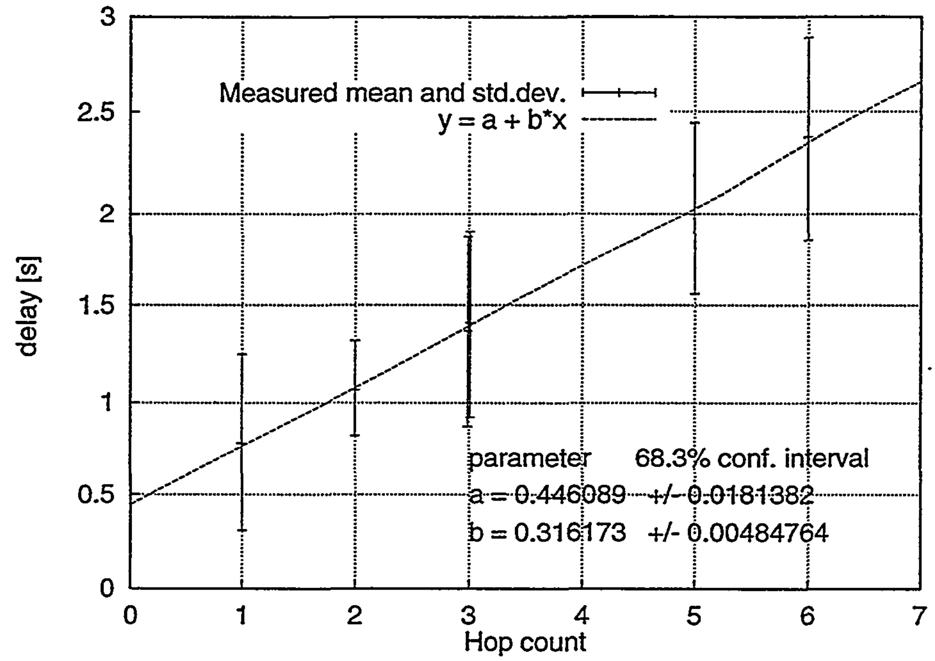


Fig. 37. Response time as a function of hop count. One radio hop increases the response time of short test messages by 0.316 seconds.

8.4 AUTONET/ACTIONET IN DISTRIBUTION AUTOMATION

Autonet is a mobile telephone service offered by a telecommunication operator. The network can transfer normal voice calls and it has a connection to a public switched telephone network (PSTN). The devices that are used to build the Autonet infra structure are also available from Nokia for building private networks, with the brand name Actionet. The radio units have a standard MPT 1327 that specifies the radio path, and MAP27 that specifies the interface between the radio unit and RTU, see Figure 38.

The Autonet/Actionet system is analogue technology in voice communication, but can transfer Status Messages in the signalling channel. In this project, the usability of the status messages for distribution automation is studied.

The coverage of Autonet in Finland is not very good, but the possibility to build private networks using the same devices makes this technology interesting. The project will study the response time, throughput, retry times, etc. of the message traffic.

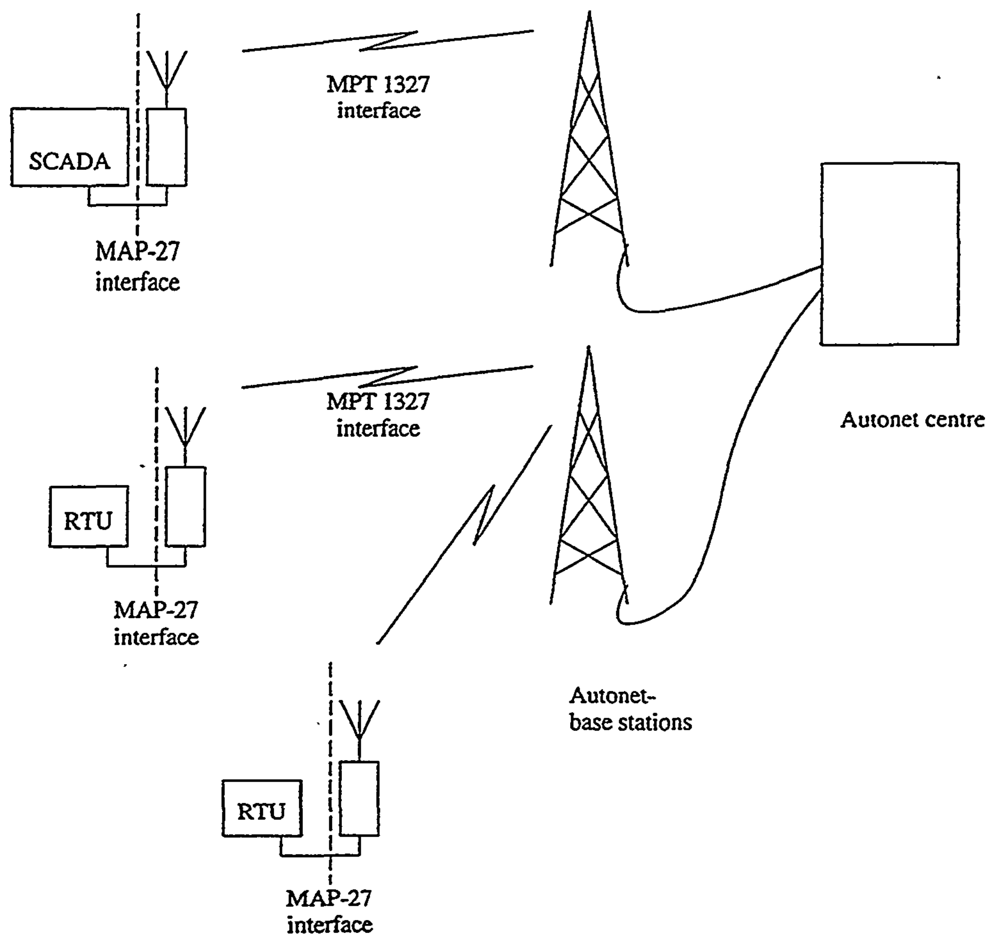


Fig. 38. Autonet / Actionet principle in Distribution Automation.

The partners in this task are:

- Nokia Private Mobile Radios (PMR), the manufacturer of the base stations and radio units, has provided radios, software and documentation.
- Helsinki Telephone Company, a telecommunication operator, has provided necessary phone numbers and permission to do communication in the Autonet network.
- Helsinki Energy has provided some test sites.

The communication software, provided by Nokia PMR, was modified at VTT so that the program sends and receives precisely time stamped test messages. The software was set to run on computer serial ports connected to MAP-27 radios and run for several days in different places. Test messages were sent from one computer and echoed back by the other computer and the turnaround time for this was calculated from time stamped log messages. Figure 39 shows hourly means and minimum and maximum values at one test site.

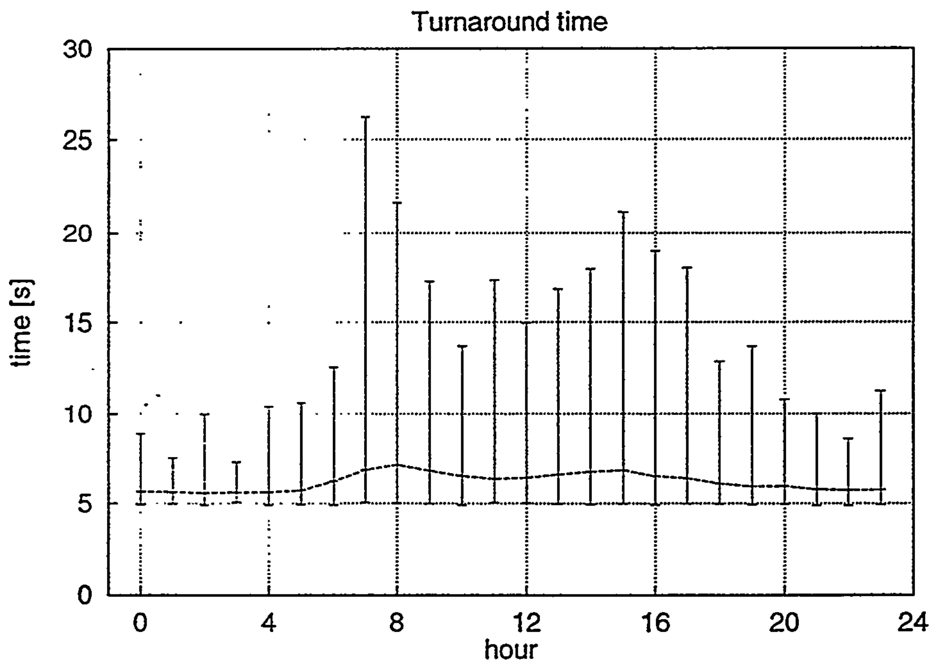


Fig. 39. Turnaround times in Autonet Short message test.

9 A SCHEME FOR A FUTURE DISTRIBUTION AUTOMATION SYSTEM IN FINNISH UTILITIES

Matti Lehtonen and Seppo Kärkkäinen, VTT Energy
Jarmo Partanen, Lappeenranta University of Technology

This paper summarizes the results of a project, the aim of which was to define the optimal set of functions for the future distribution automation (DA) systems in Finland. The general factors, which affect the automation needs, are first discussed. The benefits of various functions of DA and demand side management (DSM) are then studied. Next a computer model for a DA feasibility analysis is presented, and some computation results are given. From these, the proposed automation scheme is finally concluded.

9.1 GENERAL TRENDS IN POWER DISTRIBUTION

There is an increasing demand to restrict the environmental impacts and to reduce the emissions of energy production and energy use. In Finland the targets for the reduction of emissions into the environment by the energy sector by the year 2000 are /4/:

- to reduce sulphur dioxide emissions from the level in 1980 by 80 %,
- to reduce nitrogen oxide emissions from the level in 1980 by 30 % and
- to bring the increase in carbon dioxide emissions to a halt in the second half of the 1990s.

This calls for an efficient end use of energy. The official target is to reduce specific consumption figures by 10 to 15 per cent, alternately sector by sector, from the level of 1990 by the year 2005. The total effect of conservation in 2005 is calculated to reach 5 TWh (ca. 5 %) for electricity, compared to a consumption trend without conservation. In the case of medium and small size customers, it is the energy utility who has the best possibilities for promoting the energy efficiency. This can be done by distribution automation, appropriate tariff design, different types of campaigns, or customer consultation like energy audits, for example.

Environmental reasons will increase the use of non-fossil power generation, like wind power or solar power. These plants will be of small scale, and typically connected to the grid in the medium voltage distribution network level. The demand for energy efficiency will also increase the use of small scale co-generation of heat and electricity. For a full utilization of small scale generation it will be necessary that these power plants are remotely controlled and remotely metered, and that they also are connected into the automation systems of the utilities.

Due to the environmental interest of the public, the construction of new power distribution networks is also becoming more difficult and hence more expensive. This puts pressure on a more efficient use of the capacity of the existing distribution facilities. On the other hand, the energy losses of the distribution networks are large, in Finland about 1.6 TWh per year, which is worth 400 million FIM. Hence, if the operation practices can be improved, the monetary savings due to reduced losses can be significant.

Also the quality of the power supply is becoming of higher interest to the customers. The international standardization work is in progress, and it is expected that the supply quality will be strictly regulated in the future. The defining of electricity as a product also requires more responsibility from utilities on the quality of power. Improving the quality often requires large investments in the distribution network. Hence, it is not in the utilities interest to maintain too high a quality, but rather to optimize its level within the limits given by the authorities. For this, it is important to track the quality attributes (harmonics, voltage levels, flicker, etc.) on a more or less continuous basis in several network locations. This requires an extensive system for measurement and analysis.

In monetary terms, the most important quality factor is the reliability of the power supply. Power outages cause extensive economic damage in the form of production losses, broken equipment, spoilt raw materials, etc. The major part of outages experienced by the customers is due to faults in the medium voltage distribution networks. In Finland for instance, the estimated losses due to these outages are about 100 to 300 million FIM per year.

Today, one of the biggest changes and also highest challenges to the electricity distribution companies in Finland is the deregulation of the electricity market. The new electricity act including the free electricity market will most likely come into force in 1995. The businesses of electricity trade and distribution network operation must be separated from each other. Basicly the customers will have the right to choose between several suppliers of electricity, the network owner having the duty to transmit and distribute the energy on an equal basis. In the first year, the law is only applied to the customers having a peak power of 500 kW and more. After a one and a half year transition period, the free market will concern all the customers, regardless of their size.

From the DA point of view the establishment of a free electricity market will increase the need for energy measurements, especially remote meter reading, as well as the exchange and processing of the associated data and information. It also will drastically change the organization and the operation practices of the electric power companies.

9.2 BENEFITS OF DA AND DSM

The benefits of distribution automation and demand side management can broadly be classified into two categories: 1) direct benefits to the distribution utility itself or to the customers, and 2) better adjustment of the utility to the changes in and to the new demands of the operation environment.

In the first benefit category we have:

- reduction of outage costs
- savings in network investments
- reduced peak power demand
- reduced energy losses
- savings in labor costs

and in the second category:

- optimized voltage quality
- more efficient end use of electricity
- reduced environmental effects
- better competitiveness in the free electricity market

The basic difference between the two groups is, that the benefits in the second category are much more difficult to assess in monetary terms than those in the first one. It is clear, however, that they will, in the longer run, be of extremely high importance. In what follows, the benefits in the first category only are discussed in more detail.

In consideration of electricity saving for customers due to DSM, it might have both positive and negative effects on the economy of the utility depending on the local conditions of the utility and measures taken by the customer. Generally, electricity saving decreases the revenues of the utility, but on the other hand it also decreases costs in the purchase and generation of electricity as well as in distribution. These aspects are discussed in /25/, and in the following, only those parts of DSM are taken into account which have direct connections to DA (like load management).

The reduction in outage costs has so far been the major benefit of network automation. With the remote control of line switches of overhead line networks solely, the distance between the controlled points being about 15 to 20 km, the outage costs have been cut by about a half /27/. The outage costs can further be reduced by developing fault location techniques, i.e. fault indicators and computational fault location.

In the future, it will also be possible to detect and locate part of the temporary faults and the faults with high fault resistances. In this case, the critical fault type is a single phase to earth fault in overhead lines. The fault often begins with a very high resistance, and evolves only gradually into a fully established earth leakage requiring protective actions. This kind of fault can be detected well in advance by a careful analysis of neutral voltage, and in many cases the permanent fault and the corresponding outage can completely be avoided.

Typical costs of supply outages for different customer categories are given in Table 5. The values are taken from a recent Nordic study. The values for residential customers are based on the willingness to pay, whereas those for agricultural customers are defined according to the willingness to accept. The figures of the three other major classes are based on the direct evaluation of the costs and losses by the customers themselves. According to the study /33/, the costs of short outages are relatively high. It should also be stressed that the short repetitive outages (3 outages of about 1 minute within a period of 15 minutes) usually cause high monetary losses. Thus, such solutions a network automation should be favored, which not only shorten the outage time, but also reduce the number of outages. An example is the use of fault current indicators in the switching stations in line locations. By the use of the indicators, it is possible to reduce the number of trial switchings needed during the course of fault location.

Table 5. Typical values for average outage costs in different customer classes in Finland (DKK/kW) /28/.

Outage duration	*1s*	*3x1min*	*1h*	*4h*	*8h*
Customer class:					
Residential	-	-	5	20	73
Agricultural	-	-	38	-	409
Industrial	15	31	78	225	409
Commercial	13	30	88	232	478
Public	3	8	28	74	165

DKK = Danish Crown

The above discussion applies to the rural networks with overhead construction. In underground systems of urban areas the situation is somewhat different. According to the studies in Finland, the outage rates in underground cable networks usually are so low, that the remote control of line switches hardly is profitable. Some other solution must be found for medium voltage network automation in these cases. One of the most promising alternatives is the remote reading of fault current indicators, located in the MV/LV distribution transformer stations. This is a fairly inexpensive way to cut that part of the outage time, which is due to the location of the faulty line section /26/.

The savings in network investments is the other major benefit class. Due to distribution automation and also demand side management, investments can be reduced mainly for three reasons:

- better knowledge of load behavior, which allows a smaller margin between actual and rated loads
- reduced load flows during the peak demand
- more flexible use of the distribution capacity

A good example of the effect of rating margin is the distribution transformer. Thanks to the favorable cooling conditions in Finland, these devices can carry a peak load of 130% through 150%. Depending on the load factor, the most economical peak load of the distribution transformers varies around 80% of the rated load. However, in most cases the actual peak loads are well below this figure. This opens tempting possibilities for investment savings by increasing the average loading of these devices. The critical automation function with regard to this benefit is the distribution load estimation.

The load flows during the peak demand can be reduced by load control and other DSM functions, by appropriate voltage control and by reactive power compensation. The latter two functions are important especially in rural systems, where voltage drop is the limiting factor for distribution capacity. This is the case especially in abnormal operation conditions, where reserve connections are needed. If the switched capacitor unit is installed in the remote controlled line switch station, located in some line crossing or point of the network, the remote control of reactive power compensation can be used effectively to support the distribution voltage in various operating conditions. The effect of voltage control is to allow the utility to reduce active and reactive power flows in the peak demand period by temporarily lowering the supply voltage. Essential for this function is a good enough knowledge on voltages in the customers locations, so that the risk of violating the voltage limits set by quality standards is minimized.

Investment savings are to be expected also through more flexible operation of the distribution network, made possible by line switch remote control and effective computerized tools for switching planning. This is, again, of value especially in abnormal situations. Suppose, for instance, that the main transformer of a high voltage / medium voltage substation is temporarily out of operation. The automation system enables quick switching of outaged lines to the neighboring stations. Furthermore, the load of these stations can in turn be relieved by other adjacent substations. This reduces the investments needed for reserve connections in the medium voltage system.

Reduction in power and energy costs is to be expected through load control and other DSM functions and to a lesser degree thanks to reactive power compensation and network operation optimization.

Compared to the present situation, the performance of direct load control can further be improved by appropriate computerized optimization models. However, in the future, a better gain is expected through dynamic tariffs, which set the responsibility for control measures with the customers. The idea of dynamic tariffs is to change the electricity price flexibly according to the real production or purchase costs, but within mutually agreed limits. The best result is achieved, if the load shaving is based on the operation of the customers own automation system (e.g. home or office automation). For this, interfaces are being developed to integrate the utilities' and customers' automation systems.

Savings in labor costs are expected in operation and planning of the power system. Examples are routine switching and trouble shooting in the case of network faults. In some cases the labor cost savings are the largest benefit factor of the function. Among these kinds of functions are the remote reading of energy meters and the processing of telephone calls of the customers experiencing an outage.

9.3 ASSESSING THE COSTS AND BENEFITS OF DA AND DSM SYSTEMS

Both the costs and the benefits of various automation functions are partly overlapping. This makes the economic analysis of DA and DSM systems complicated and tedious. The feasibility analysis can most conveniently be made using a computer program. In this section a software package for this purpose, and the analysis results for a group of Finnish utilities, are briefly presented. The automation functions considered are listed in Table 6. The benefits, for which a monetary value is given, are shown in the second column of the table. The principal structure of the software package is illustrated in Figure 40. The input data is divided into four classes:

- the utility specific data
- general calculation parameters
- the configuration of automation functions
- general cost parameters

The utility specific data includes the information, which only is applicable to the distribution company concerned. In this file we have, for instance, statistical information of the utility and some average technical data of its network.

The general calculation parameters include such information, that is common to all the utilities, like the parameters of outage costs to different customer classes. Another example is the parameters, which control the efficiency of the automation functions, like the per cent reduction of outage times due to remote controlled switching stations, or the reduction of peak load due to a 1% reduction of the supply voltage. This data is often based on experience and must be collected from several sources.

The configuration of automation functions is simply a list of the functions that are taken into account in the analysis. The software package allows for any combination of functions mentioned in Table 6.

The general cost parameters include the data of the costs of the computer equipment, computer software packages, data transmission systems, automation related power equipment etc. The costs are further divided into purchase, installation, operation and maintenance costs.

The output data of the software system is correspondingly divided into two classes:

- intermediate results of technical computations
- results of cost/benefit data

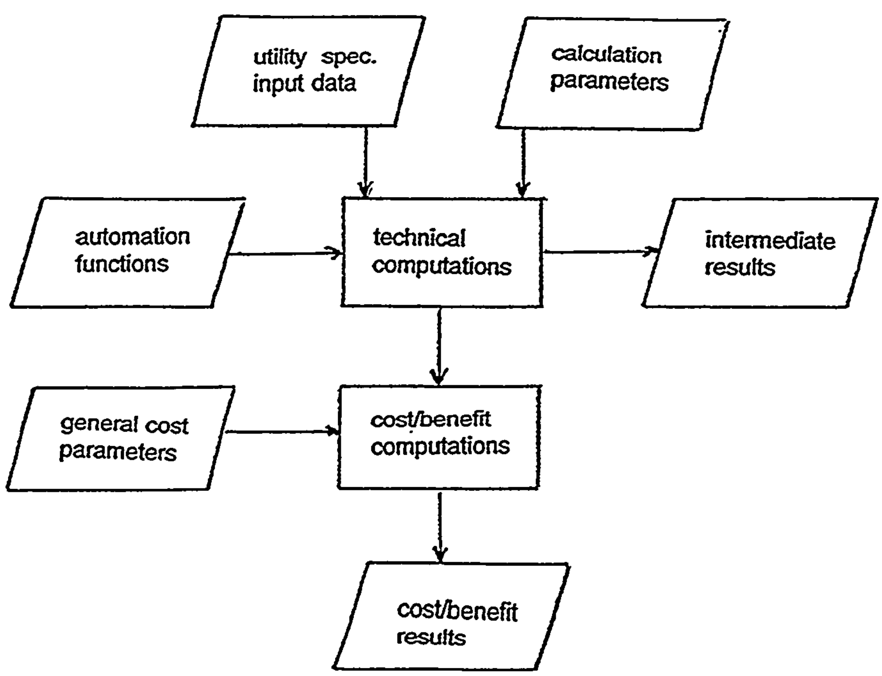


Fig. 40. The structure of the software package for DA/DSM cost/benefit analysis.

The intermediate results of the technical computations are used for checking the consistency of the input data and for assessing the quality of the analysis in general. Some important calculation results are also given, like the average optimum size of a compensation capacitor unit in the feeder positions, or the average ratio of maximum load current and the rated current of the distribution transformers. The final computation results are stored in a separate file. The results include the total costs and benefits for the given automation function configuration and their decomposition into various classes.

The costs and benefits of different automation functions, listed in Table 6, are presented in more detail in Appendix 1. The networks studied were two urban and four rural ones. The results can be summarized as follows:

- The remote control of line switches was justified for all the rural networks but not for the urban ones. The major part of the benefits, about 90 to 97%, comes through the reduced outage costs to the customers. In urban underground systems, the fault frequencies are substantially lower than in rural networks. Hence the outage cost reduction is also smaller.

- Fault indicators, at remote controlled line switches, mainly reduce the costs of repetitive short outages due to trial switching. The function is economical in most of the rural systems.

- Independent fault indicator stations, at locations in addition and separate from line switch remote control stations, are cost effective in all the four rural systems.

- Computational fault location, based on the integration of protective relays, substation telecontrol system and the distribution data management system, is justified in all the rural systems and also for one of the urban utilities.

- The remote control of fault indicators at the secondary substations, or ring main units, was found to be very cost effective for both the urban systems. Here it was assumed, that 20% of the indicators are equipped with communication.

- For the high resistance earth faults (in high impedance earthed systems), it was assumed, that 10% of the faults can be detected by neutral voltage analysis and by partial discharge based techniques. This function was found to be very cost effective for all the utilities.

- The reactive power compensation in MV line locations was cost effective for two rural systems only. Here however, the major part of the benefits were due to the voltage drop reduction, and hence the postponed reconductoring. The loss reduction alone was not enough to justify the investments.

- For voltage control, it was assumed that a part of the marginal between rated and actual voltage drop can be used for load control purposes, by reducing the supply voltage during peak demand periods. The benefits turned out to be very high compared to the costs.

- The costs and benefits of direct load control were studied for those utilities only, which already had implemented this function. The function was found to be cost effective in two of three cases.

- Load estimation is a function needed for several purposes, as for producing input data for various network operation and optimization functions. Here, when assessing the economy of this function, only the benefits due to the reduced marginals between rated and actual loads of the network components, were taken into account. The function was found to be very cost effective in five cases.

- Switching planning and network topology optimization are functions, which reduce the power and energy losses in the distribution network. For these, the benefits are very high compared to the costs in all the analyzed cases.

- Remote metering and the use of dynamic tariffs must be implemented at the same time. This application is very cost effective in the utilities, where direct load control is also used. This is because the central equipment (distribution line carrier) can be shared by the two applications. In this analysis, it was assumed that 15% of the customers in industrial, commercial or the public sector are metered remotely.

Table 6. *The distribution automation and demand side management functions considered in the software package of VTT for DA/DSM cost/benefit analysis. The abbreviations for benefits are: OC for outage costs, L for labor costs, INV for investments, P for peak demand, E for energy demand and losses and Q for supply quality. (Those benefits in parenthesis are not assessed in monetary terms).*

Functions	*Benefits*
Medium voltage switch control and fault clearing *-- line switch remote control* *- fault indicator remote reading* *- fault distance computation*	*OC,L*
High resistance fault detection	*OC,(L)*
Voltage control and reactive power control	*P,E,INV,(Q)*
Direct load control	*P,(E),INV*
Distribution load estimation and component load monitoring	*INV,(L)*
Switching planning and topology optimization	*P,E,(INV,L)*
Remote metering and dynamic tariff application	*P,(E),L*

9.4 THE PROPOSED SCHEME FOR FUTURE DAS IN FINNISH UTILITIES

The proposal for a future distribution automation system in Finnish power companies can be deduced from the above cost benefit analysis and from the general factors stated before. The proposed functions are as follows:

<u>Computer systems in control center</u>

HV/MV substation telecontrol system system:
- remote control of substation switches
- remote control of line switches
- feeder current monitoring
- busbar voltage monitoring
- on-load tap-changer control
- transformer load monitoring
- weather data
- equipment condition monitoring
- interface to the protective relay system

Distribution data management system (DMS):
- network diagram updating
- network topology updating
- network monitoring by computations
  - fault currents
  - voltages
  - load flows
- network planning
- maintenance planning

Support system for MV network operation (NOP):
- network operation optimization
  - volt/var control
  - network topology optimization
- distribution load estimation
- alarm processing
- customer trouble call processing
- fault location and supply restoration
- operation report generation
- demand forecasting

Distribution energy management system (DEM):

- load model updating (load research)
- load forecast
  - short term
  - long term
- energy balance updating
  - technical
  - commercial
- load control optimization
- tariff design
  - fixed tariffs
  - dynamic tariffs
- electricity trade monitoring and optimization
- spot price forecasting
- metering for billing
- energy purchase optimization
- small scale production monitoring and control
- demand side management (DSM) planning
- DSM impact verification

<u>HV/MV substations:</u>

- fault distance computation
  - short circuit faults
  - earth faults
- remote equipment monitoring
- voltage control (on-load tap-changer)
- high resistance earth fault indication
- current and voltage measurements
- energy measurements

<u>MV switching stations (overhead systems):</u>

- line switch remote control
- var control
- fault indicator monitoring
- measurements (U,I,P,Q)

MV fault indicator stations (overhead systems):

- fault indicator monitoring
- measurements (U,I,P,Q)

MV/LV secondary substations (urban systems):

- fault indicator monitoring
- var control
- distribution transformer monitoring
  - load
  - condition
- voltage quality monitoring
- MV and LV measurements

LV network and customers:

- remote metering
- supply voltage quality monitoring
- dynamic tariff application
- measurements for load research
- DSM information to the customers
- interface to customer automation

Of the computer systems at the control center level, SCADA and DMS are already well established with regards to both the functions and the techniques of implementation. Here the most important item of development is the data exchange between these systems and other computer systems of the utility. In the future, the mutual role of these systems may also change so that SCADA takes over such DMS operations which have high requirements for response times.

With regard to the computer systems, the biggest demand for development is in the NOP and DEM systems. According to the feasibility analysis, the benefits of a NOP system are relatively large compared to the costs. These benefits mainly come through two types of functions, network operation optimization and network component load monitoring (state estimation). A DEM system is of extremely high importance to the electricity selling business in a deregulated environment.

In the field of MV network automation, the most important item of research and development is fault location and fault indication. In rural overhead systems, independent fault indicator stations should be developed. In urban systems, the most important function is the remote monitoring of MV fault indicators located at the secondary substations. Together with these applications, as many measurements as possible should be implemented, in order to produce raw data for the network optimization and state monitoring functions.

At the LV system level, the customer related functions are the most important. The use of dynamic tariffs can be very cost effective, provided that equipment costs are shared with the direct load control. If the energy meter or remote terminal unit has plenty of excess processing capacity, the functions for supply voltage quality monitoring are also worth implementing.

10 DISTRIBUTION LOAD ESTIMATION (DLE)

Anssi Seppälä and Matti Lehtonen VTT Energy

10.1 GENERAL

The load research has produced customer class load models to convert the customers' annual energy consumption to hourly load values. The reliability of load models applied from a nation-wide sample is limited in any specific network because many local circumstances are different from utility to utility and time to time. Therefore there is a need to find improvements to the load models or, in general, improvements to the load estimates.

In Distribution-Load Estimation (DLE) the measurements from the network are utilised to improve the customer class load models (Fig 41).

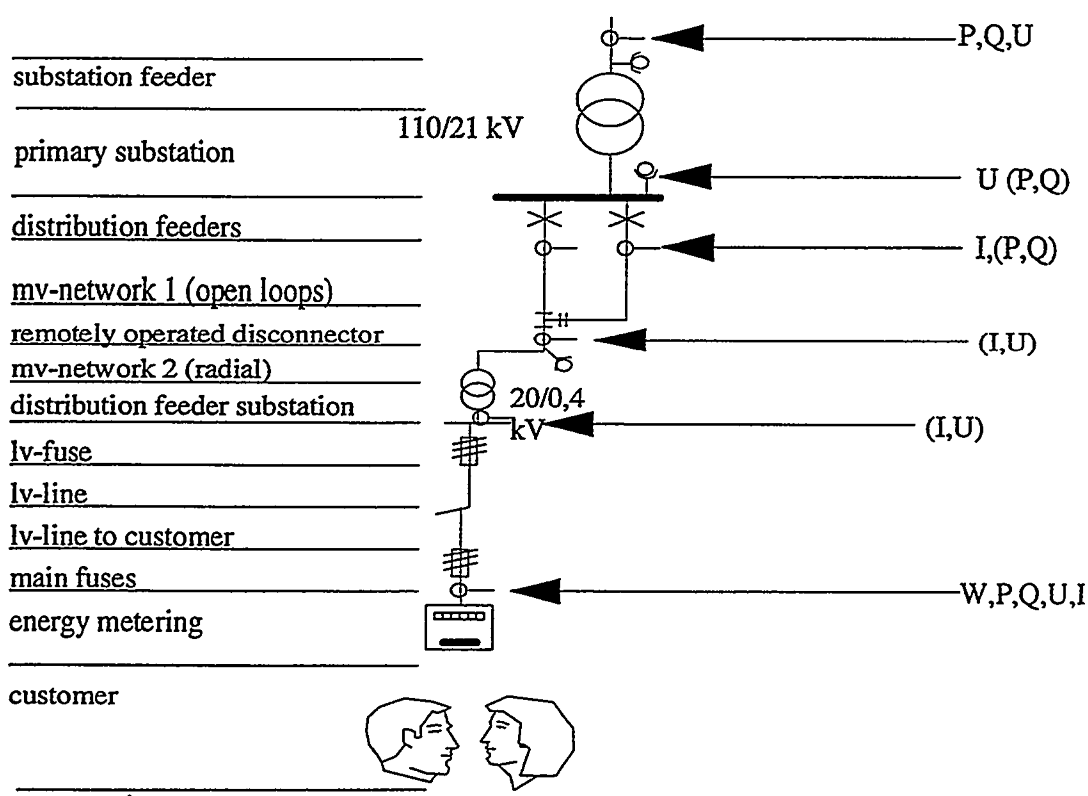


Fig. 41. Possible measurements in distribution network.

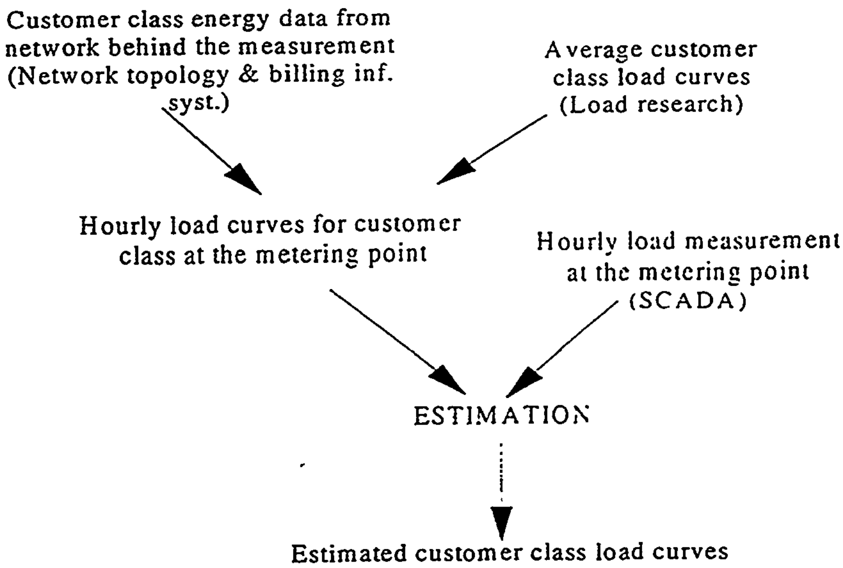


Fig. 42. The data flow of distribution load estimation (DLE) process.

The results of DLE will be new load models that better correspond to the loading of the distribution network but are still close to the original load models obtained by load research. The principal data flow of DLE is presented in Fig. 42.

10.2 THE ESTIMATION PROCEDURE

10.2.1 Definition of weighted least squares estimation

We assume that the distribution network is radial operated. Each meter measures the load for a specific part of the network. Usually the load metering points are at the primary substations, but also metering can exist deeper in the network (Fig. 41). The medium voltage feeders are usually equipped with current metering and the substation primary feeder is also equipped with active power metering. Fig. 43.

To calculate the hourly load estimate for each customer class we use the simple customer class load model where the customer class hourly loads are obtained from annual energy consumption by:

$$\overline{P}(t) = L_c(m(t), d(t), h(t)) \cdot W_a \tag{6}$$

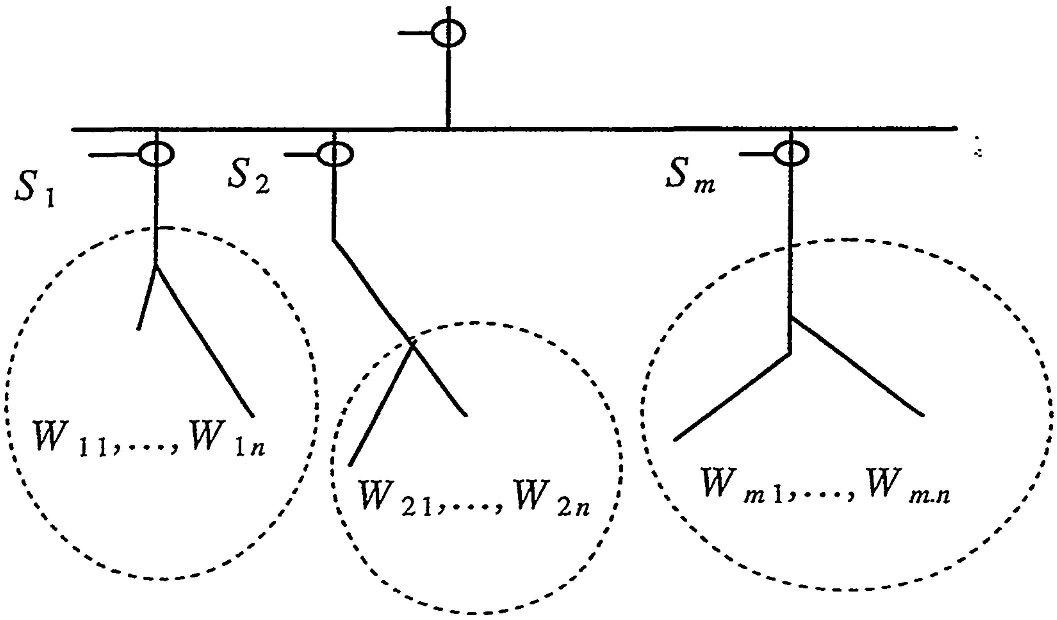


Fig. 43. Distribution station with feeder measurements $S_1 \ldots S_m$. Over an area i the total annual energy of a customer class j is W_{ij}.

In the following mathematical manipulation, the load model is briefly presented as the equation

$$z = xW \tag{7}$$

where z denotes the customer class' one hour's expected load $\overline{P}$ derived from the model, W corresponds to annual energy W_a and x corresponds to the factor L_c, which represents the relationship of customer's hourly load to the annual energy consumption.

The annual energy in different areas of the network is represented by W_{ij}, where i defines the area and j defines the customer class.

In the distribution network, the total load is a sum of the loads of distinct customer classes $1 \ldots n$. The total load of the customer class in the network is z_j. The total annual energy of each class j in the network is presented briefly as W_j

$$W_j = \sum_{i=1}^{m} W_{i,j} \tag{8}$$

The total annual energy consumption of customer classes $1 \ldots n$ over areas $1 \ldots m$ are (Fig. 43).

$$\begin{cases} W_1 = W_{11} + \cdots + W_{m1} \\ \vdots \\ W_n = W_{1n} + \cdots + W_{mn} \end{cases} \tag{9}$$

The equation between the actual customer class load and the load obtained from the model can be written adding an error term v_j:

$$\begin{cases} z_1 + v_1 = W_1 x_1 \\ \vdots \\ z_n + v_n = W_n x_n \end{cases} \tag{10}$$

The matrix form of the equations between customer class loads and customer class load models is

$$\begin{bmatrix} z_1 + v_1 \\ \vdots \\ z_n + v_n \end{bmatrix} = \begin{bmatrix} W_1 & \cdots 0 & 0 \\ \vdots & \ddots & 0 \\ 0 & \cdots 0 & W_n \end{bmatrix} \cdot \begin{bmatrix} x_1 \\ \vdots \\ x_n \end{bmatrix} \Leftrightarrow \mathbf{z} + \mathbf{v} = \mathbf{W}_z \mathbf{x} \tag{11}$$

where **z** is one column matrix with the number of rows equal to the number of customer classes. $\mathbf{W}_z$ is a diagonal matrix of total annual energies of customer classes in the network. **x** is one column matrix of load model parameters.

For each load measurement S_i in the network we can write equations, where the value of the measured load is the total of the loads of customer classes in the corresponding area. The equations can be written adding an error term e_i

$$\begin{cases} S_1 + e_1 = W_{11} x_1 + \cdots + W_{1n} x_n \\ \vdots \\ S_m + e_m = W_{m1} x_1 + \cdots + W_{mn} x_n \end{cases} \tag{12}$$

The error term also includes the network losses unless the losses are defined as one customer class. The matrix form of the equations is

$$\begin{bmatrix} S_1 + e_1 \\ \vdots \\ S_n + e_n \end{bmatrix} = \begin{bmatrix} W_{11} & \cdots & W_{1n} \\ \vdots & \ddots & \vdots \\ W_{m1} & \cdots & W_{mn} \end{bmatrix} \cdot \begin{bmatrix} x_1 \\ \vdots \\ x_n \end{bmatrix} \Leftrightarrow \mathbf{S} + \mathbf{e} = \mathbf{W}_S \mathbf{x} \tag{13}$$

S and **e** are one column matrixes where the number of rows is equal to the number of measurements. $\mathbf{W}_S$ is a matrix where the number of rows equals the number of measurements and the number of columns equals the number of load classes. $\mathbf{x}$ is one column matrix where the number of rows equals the number of customer classes.

The two matrix equations 11 and 13 presented together now describe the total system of customer class load models. The load models describe the customer class loads in the network $\mathbf{z}+\mathbf{v}=\mathbf{W}_z\mathbf{x}$ and the relation between the measurements and load models is described by the equation $\mathbf{S}+\mathbf{e}=\mathbf{W}_S\mathbf{x}$. Combining these equations we get an equation of partitioned matrixes

$$\begin{bmatrix}\mathbf{z}\\ \mathbf{S}\end{bmatrix}+\begin{bmatrix}\mathbf{v}\\ \mathbf{e}\end{bmatrix}=\begin{bmatrix}\mathbf{W}_z\\ \mathbf{W}_S\end{bmatrix}\mathbf{x} \tag{14}$$

Now we want to find $\mathbf{x}$ that minimises the error $\begin{bmatrix}\mathbf{v}\\ \mathbf{e}\end{bmatrix}$.

For this kind of optimisation problem with several parameters, we will use the method of Weighted Least Squares Estimation (WLSE), which is widely utilised in the state estimation of transmission networks.

The WLS estimate for $\mathbf{x}$ in eq. 14 is then

$$\hat{\mathbf{x}}=\left[\begin{bmatrix}\mathbf{W}_z\\ \mathbf{W}_S\end{bmatrix}^T\mathbf{R}^{-1}\begin{bmatrix}\mathbf{W}_z\\ \mathbf{W}_S\end{bmatrix}\right]^{-1}\begin{bmatrix}\mathbf{W}_z\\ \mathbf{W}_S\end{bmatrix}^T\mathbf{R}^{-1}\begin{bmatrix}\mathbf{z}\\ \mathbf{S}\end{bmatrix} \tag{15}$$

10.2.2 Definition of the weights

The weights in $\mathbf{R}^{-1}$ are inverses of the variances of models and measurements. This leads to a solution where the estimates of the load models and measurements of higher variance are subject to greater changes than those with lower variance.

Now the question is to select which model of variance should be used. One choice is to use the square of the standard deviation s_P of the load model and the other choice is to use the square of the standard deviation of the sum of k customers ($s/\sqrt{k}$). While the load research data is from different times and usually different population, the variability of the model error at the specific hour is not only a function of the number of customers. While we have no information from the other factors of error variance we rather apply similar simple customer class model for standard deviation

$$s_P(t)=s_{Lc}(m(t),d(t),h(t))\cdot W_a \tag{16}$$

to evaluate the variance $\sigma^2=(s_P)^2$. The value of standard deviation of load models in general ranges between 30 % ... 100 % from the mean.

For the network measurements the standard deviation needs to be approximated. One practical method is first to approximate the maximum error. The distribution of the error is unknown, but assuming the error to be roughly normally distributed, the standard deviation is about 1/3 of the maximum error.

For example, when we have a current measurement, the evaluation of active power from current includes an error (the cos ϕ is usually unknown and needs to be estimated too) which may have a standard deviation of 10 % from the absolute value of the measurement. In the case of direct active power measurement the error could be 1 % or less. Thus the direct measurements have smaller error variance than the load models. Also the resolution of the SCADA communication between the remote terminal and central computer bring some error to the registered measurement values.

Only relative differences between weights in $\mathbf{R}^{-1}$ are important. When in practice the measurements get much smaller variances, the solution will more likely change the load models than the measurements.

10.2.3 Application of estimation

Finally with the help of the result $\hat{\mathbf{x}}$ we can solve the new customer class load estimates $\hat{\mathbf{z}}$ and the load at the points of measurements $\hat{\mathbf{S}}$:

$$\begin{aligned} \hat{\mathbf{z}} &= \mathbf{W}_Z \hat{\mathbf{x}} \\ \hat{\mathbf{S}} &= \mathbf{W}_S \hat{\mathbf{x}} \end{aligned} \tag{17}$$

The network losses can be taken into account in two ways. The losses may be defined as one load model; otherwise the total losses will be included in the error of the models and measurements. The definition of a load loss model for estimation should be a subject for further studies.

10.3 A DLE EXPERIMENT WITH FOUR SUBSTATION FEEDER MEASUREMENTS

The previous DLE method will be dealt with here with some substation feeder data. Load current measurements from four 20 kV distribution feeders and the customer class information has been used to build the equations presented in the previous chapter. The measurements and load models of the feeders are presented in Figures 44 and 45.

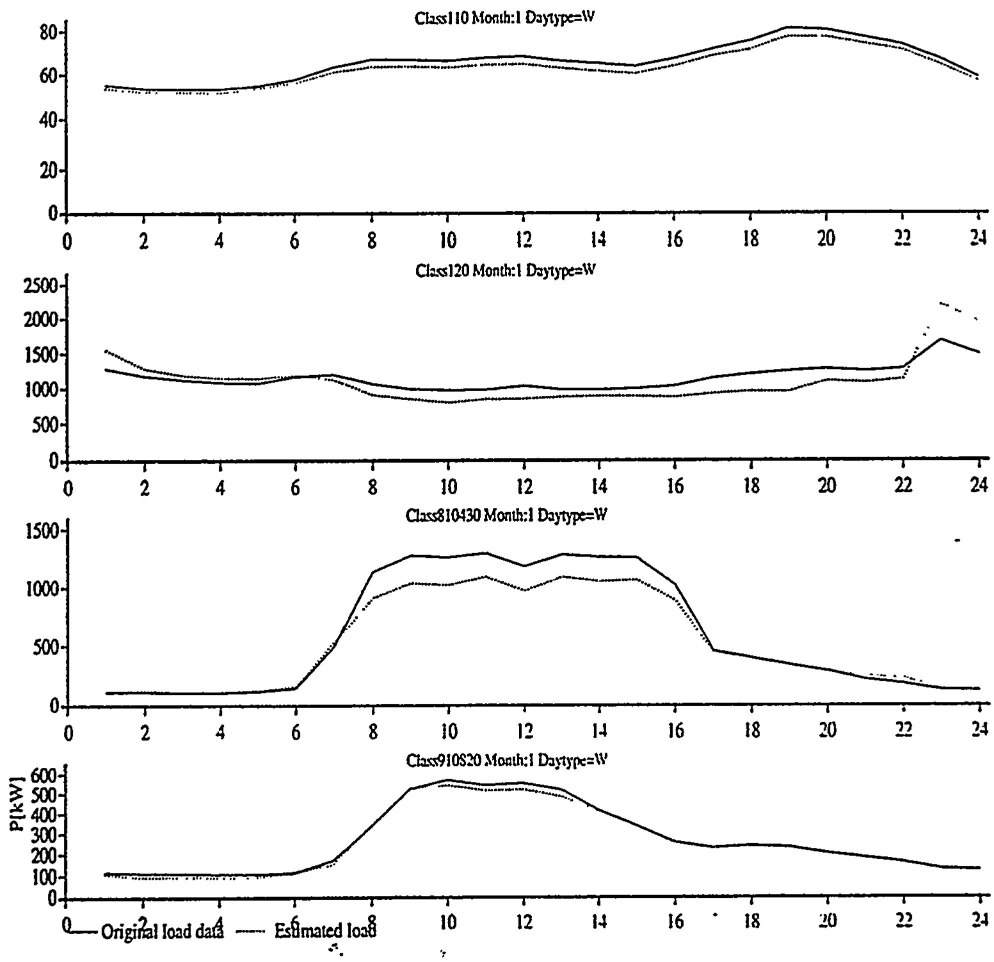


Fig.44. Examples of how estimation affects customer class load models (z_j). The result of estimation is represented by a dotted line and the original load model is represented as a solid line. 110 = direct electric heating, 120 = direct electric heating with storage water boilers, 810430 = 1 shift industry (textile) and 910820 = service (private sector). Average values for working days over January.

Figure 44 shows an example of how the models change on an average in one month according to estimation with the four substation current measurements. The error is shared between models and measurements depending on how large a share of a load model is represented in one measurement and how high the model variance is. This also means that the small or negligible customer classes are not affected in estimation.

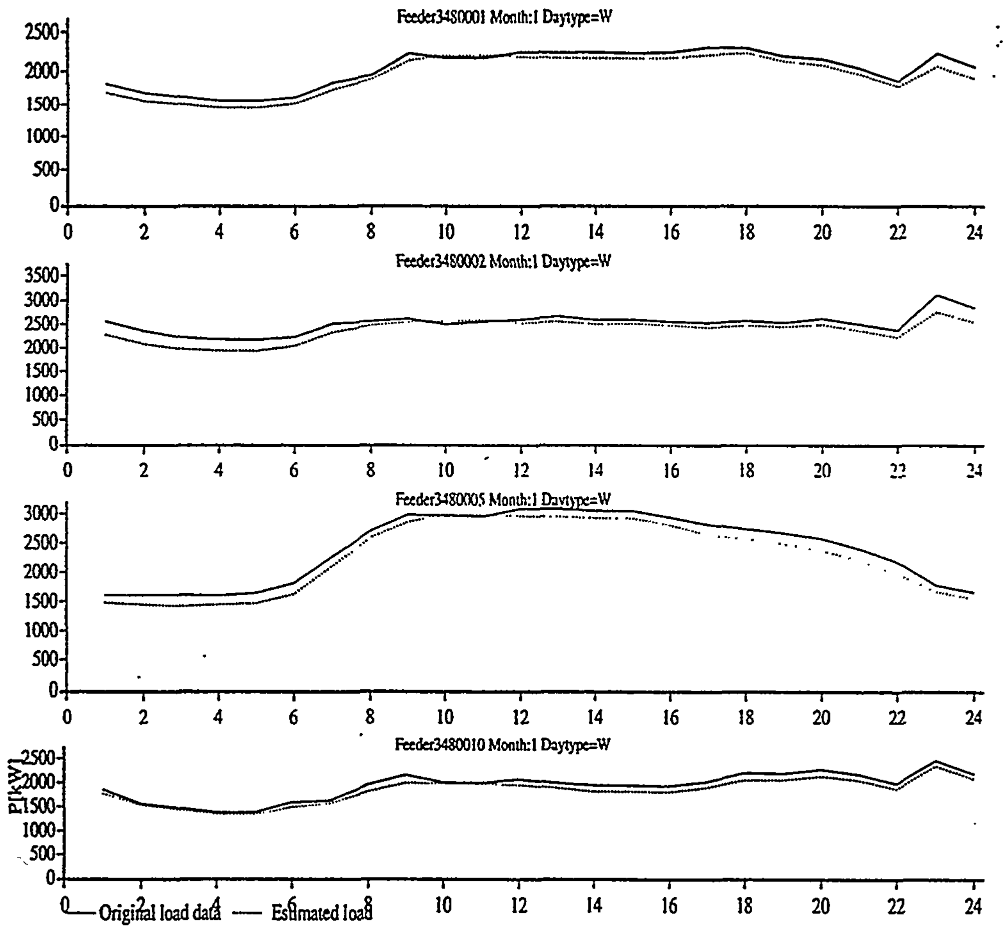


Fig. 45. Feeders from Meriniitty and Perniö substations (nr. 3480001, 3480002, 3480005 and 3480010) are the measurements (S_i) . The result of estimation is represented by a dotted line. The feeder measurement, where the values are transformed from current to active power, is represented by a solid line. Average values for working days during January.

The curve of the customer class "Electric heating with storage boilers" in Figure 44 is interesting because it shows exactly the actual situation where the utility controls the boilers simultaneously and the peak is caused by the boilers which are switched on the same time (at 22.00).

10.4 LOAD ESTIMATION WITH ONE MEASUREMENT

The simplest case of DLE is one measurement in the feeder of a radial network . Here we analyse the special case more to see if it would be possible to formulate a simpler form of load estimation for the special case of one measurement in a radial distribution network. However this result can be generalised to any radial network split to areas of one meter in the feeding point.

The form of the state equations in DLE recalling (14) is

$$\begin{bmatrix} \mathbf{z} \\ \mathbf{S} \end{bmatrix} + \begin{bmatrix} \mathbf{v} \\ \mathbf{e} \end{bmatrix} = \begin{bmatrix} \mathbf{W_z} \\ \mathbf{W_S} \end{bmatrix} \mathbf{x} \tag{18}$$

Now the $\mathbf{S}$, $\mathbf{e}$, $\mathbf{W}_s$ are one-row matrixes and the equation with one measurement can be written simply

$$\begin{bmatrix} z_1 + v_1 \\ \vdots \\ z_n + v_n \\ \sum_{j=1}^{n} \left(z_j + v_j \right) + e \end{bmatrix} = \begin{bmatrix} W_1 & 0 & 0 \\ 0 & \ddots & 0 \\ 0 & 0 & W_n \\ W_1 & \cdots & W_n \end{bmatrix} \cdot \begin{bmatrix} x_1 \\ \vdots \\ x_n \end{bmatrix} \tag{19}$$

In practice the error between the original customer class models and the measurement is known as value e'

$$e' = \sum_{j=1}^{n} v_j + e \Leftrightarrow e = e' - \sum_{j=1}^{n} v_j \tag{20}$$

For model parameters x we get the estimate for $\hat{x}_j$, $j = 1 \dots n$ in the form

$$\hat{x}_j = \frac{1}{W_j} \left(z_j + \frac{\sigma_j^2}{\sigma_S^2 + \sum_{i=1}^{n} \sigma_i^2} e' \right) \tag{21}$$

This result is useful for many practical distribution applications, where for example, the voltage drop of the radial distribution feeders is calculated separately. This result states that when the WLSE method is used the error between the loads and metering are divided in proportion to their variances.

EXAMPLE:

From a 20 kV feeder a current of 20 A was measured on Wednesday, the 15th March, 1995 14.00-15.00. The bus voltage was 20.7 kV. From the network information system we receive the information that the feeder was feeding five customer classes according to Table 7.

From the load models from load research we obtain the relation between annual energy and the corresponding hour's load as shown in Table 8.

This information was obtained from the published files of the Finnish load research project. The structure of the model is from the calendar year 1990. Thus we apply the day, March 14th, which was a Wednesday in 1990.

Table 7. The annual energies of the measured feeder.

Customer class	*[MWh/year]*
1. 1-shift industry	*1000*
2. Agriculture	*200*
3. Residential with direct electric heating	*1000*
4. Residential with storage heating	*400*
5. Residential, no electric heating	*1800*
Total	*4400*

Table 8. Customer class load models, expected load P_j and standard deviation s_j.

Customer class	Lc [W/MWh]	slc [W/MWh]	Pj [kW]	sj [kW]
1. 1-shift industry	297	133	297	133
2. Agriculture	90	64	18	12.8
3. Residential with direct electric heating	135	81	135	81
4. Residential with storage heating	24	15	10	6
5. Residential, no electric heating	101	70	182	126
Total			642	

Table 9. Class loads, variances, error/correction v_j and new estimated value.

Customer class	Class load Pj [kW]	Variance σj^2 [kW^2]	Error νj [kW]	Estimate Pj[kW]
1. 1-shift industry	297	17689	33	330
2. Agriculture	18	4096	8	26
3. Residential with direct electric heating	135	6561	12	147
4. Residential with storage heating	10	225	0.5	10.5
5. Residential, no electric heating	182	4900	9	191
Total	642	33471	62.5	704.5

From the feeder current metering we get the active power by assuming first that the load factor $\cos\phi = 0.9$. Thus $P_S = \sqrt{3} \cdot 0.9 \cdot 20 \cdot 20.7 = 710\text{kW}$. The standard error of the measurement σ_P will be approximated as 7 %, thus $\sigma_P = 50$ kW. The error between models and measurement $e = 710 - 642$ kW = 68 kW will be shared relative to the variances of the models and measurements. The result is shown in Table 9.

This shows how the difference between the total of models and the measurements can be quite easily shared between models. This method takes into account both the difference in the sizes of the customer classes and the uncertainty of the model and measurement expressed in the variances of the models and measurements.

10.5 UTILISATION OF DISTRIBUTION LOAD ESTIMATION

When integrated into the utility's information systems and SCADA the DLE does not require any additional investments. The DLE can be utilised in the distribution automation in several ways

- The output of DLE is a selection of load curves for customer categories and load classes. These curves can be utilised in forecasting purposes.
- DLE brings the possibility of continuous load research where the need of customer level recordings is reduced compared to conventional load research.
- When the electricity markets are free from regulation the DLE brings on-line information from the loads when the final load values are not available due to the time consuming clearing between producers and sellers. With the help of DLE the utility can calculate their energy balance reliably on an on-line basis.

From the DSM point of view, the DLE can be utilised in several ways, for example:

- The accurate knowledge of feeder load gives the indication for the need of DSM at a specific time (load management, real-time pricing) and site,
- the better estimates of load curves of different customer classes can be utilised in the operation of the load management system (actual timing of the load control) and estimation of the effects of load management on the total load.

The benefits of DLE can be achieved from optimal utilisation of the distribution network capacity

- maximum utilisation of network components
- finding the most profitable targets for network investments and service.

The integration of DLE to the utility's information systems is a task which requires some further experiments. The basic problem is which form of information is needed in further applications. The suggested DLE method results in new load values for each hour. Such information is handled on line and requires applications capable of accepting on line information.

Another alternative is to collect the estimated load information to a database where the data will be retrieved for further study. When large differences to applied load models occur the reason for the difference should be analysed and the current load model changed. Some of the distribution network computation applications (at least Tekla, Tietosavo and Versoft) support a load model editor which can be used to update the load models according to the information retrieved from load estimation.

The estimation algorithm is very general and brings a lot of possibilities to develop applications. For example, the results of estimated loads could be used recursively in further estimations. Such variations and improvements should be targets for further analyses especially when there is a continuously running DLE installation available to test with live data.

11 DEM - DISTRIBUTION ENERGY MANAGEMENT

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11.1 INTRODUCTION

The electricity market was de-regulated in Finland at the end of 1995 and the customers can now freely choose their power suppliers. The national grid and local distribution network operators are now separated from the energy business. The network operators transmit the electric power to the customers on equal terms regardless from whom the power is purchased (Fig. 46).

The Finnish national grid is owned by one company Finnish Power Grid PLC (Fingrid). The major shareholders of Fingrid are the state of Finland, two major power companies and institutional investors. In addition there are about 100 local distribution utilities operating the local 110 kV, 20 kV and 0.4 kV networks. The distribution utilities are mostly owned by the municipalities and towns.

In each network one energy supplier is always responsible for the hourly energy balance in the network (a "host") and it also has the obligation to provide public energy prices accessible to any customer in the network's area. The Finnish regulating authorities nominate such a supplier who has a dominant market share in the network's area as the supplier responsible for the network's energy balance (Fig. 47). A regulating authority, called the Electricity Market Centre, ensures that the market is operating properly. The transmission prices and public energy prices are under the Electricity Market Centre's control.

For domestic and other small customers the cost of hourly metering (ca. 1000 US$) would be prohibitive and therefore the use of conventional energy metering and load models is under consideration by the authorities. Small customer trade with the load models (instead of the hourly energy recording) is scheduled to start in the first half of 1998.

In this paper, the problems of energy management from the standpoint of the energy trading and distributing companies in the new situation are first discussed. The topics covered are: the hourly load data management, the forecasting and estimation of hourly energy demands, optimisation of energy production, short-term trade management, retail tariff design and planning of power purchase from the markets.

A computer system for Distribution Energy Management (DEM) is being developed. Several modules of DEM are prototyped in co-operation with three Finnish electric utilities and ABB Transmit Oy and some modules of the DEM system have already been developed for commercial use.

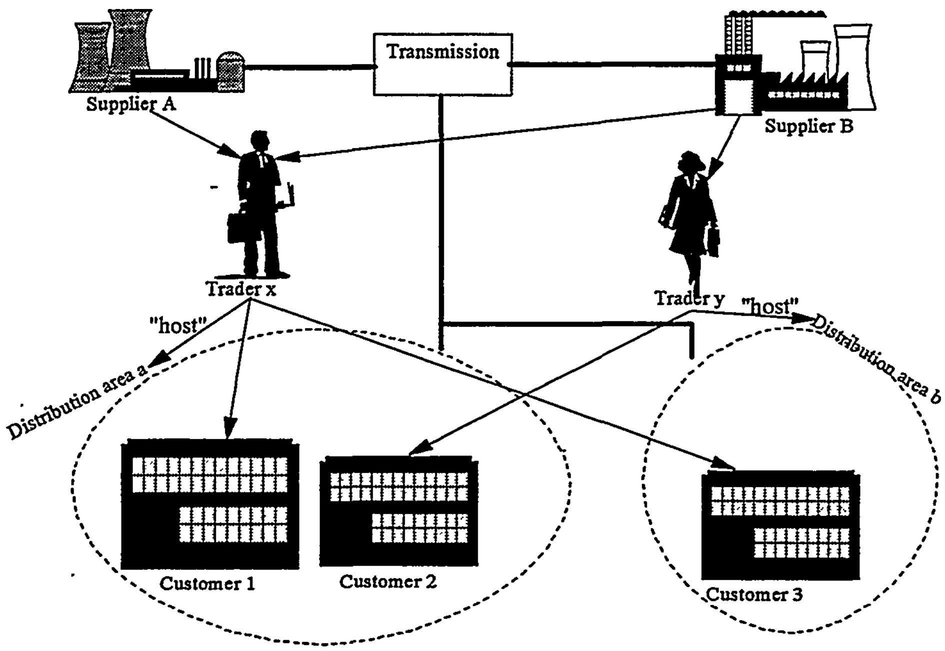


Fig. 46. In the de-regulated power market, the businesses of electricity generation, trade and transmission and distribution are separated. The network companies will remain as monopolies, but they are obliged to transmit the power, sold by any trading company, to their customers.

11.2 MOVING THE ELECTRICTY BUSINESS TO DE-REGULATION

The introduction of the free electricity market has affected the power purchase practices by bringing new facilities for power trade. It is now possible to exchange energy in the spot market either by bilateral contracts or via the Finnish power pool El-Ex (now owned by Fingrid). The participation in the Nordic power pool NordPool is also now possible.

Most of the former power purchase contracts in Finland were long-term open contracts. The distribution utilities and largest customers purchased their energy from two major Finnish power producers with quite complicated long term contracts (even 10 years). These contracts set quite a high fixed price depending on maximum power demand and various time dependent energy prices which are bound to the market prices of primary energy resources. Such arrangements will fade into history, but meanwhile some part of the energy purchase will, for few years be, based on these contracts and the new types of contracts will replace the old ones step by step. Therefore one of the first problems after the de-regulation is to manage the mixture of the old and new types of power contracts.

All participants in the market must maintain a balance between their power purchase and consumption. To maintain the balance all participants in the market need one open contract from a supplier and the open contracts between suppliers must form a direct chain to the power regulators on the national grid level.

The organisation of the national load balance settlement in Finland is such, that the local distribution utilities are responsible for maintaining daily the hourly energies for each competitive power seller in their distribution area. The energy for the distribution network's "host" supplier is derived from the network's total transmission, subtracting the other trader's energies. These local balances will then be cumulated on a national level. The hourly energy is finally settled after one month and can no longer be changed.

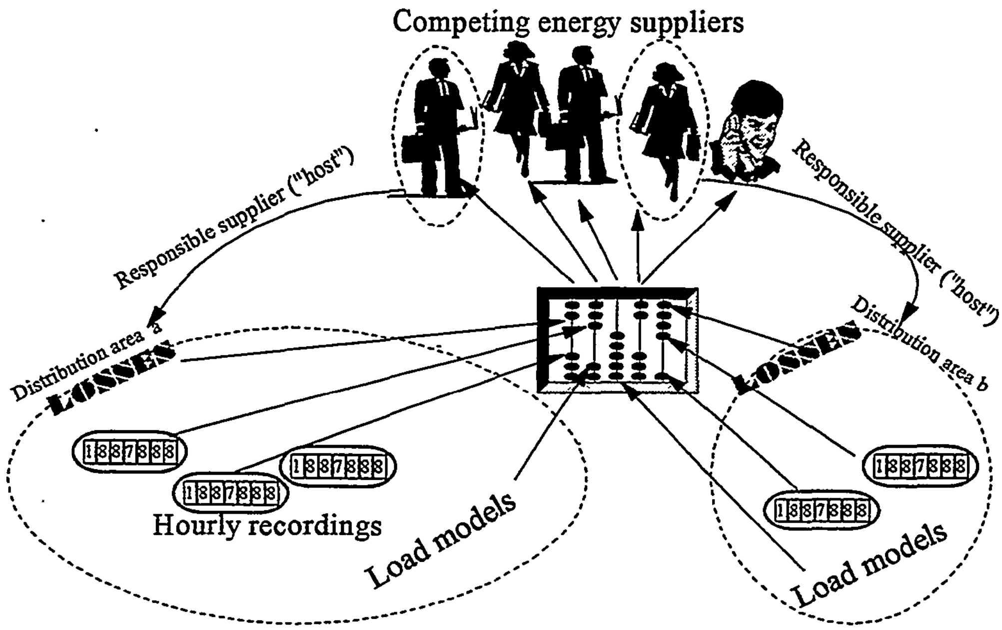


Fig. 47. The distribution networks maintain the first level of load management. The load in each network is settled between competitive suppliers and the responsible "host" supplier who provides the energy to settle the balance between traders and total transmission to the network.

The problems in this new situation have their economic and technical aspects.

The major economic challenge of the market players is to maintain the balance between purchase and sales each hour with maximum profit by making short term contracts and controlling their own generation. The planning of this task will become more difficult as the customers may change in the future. Also a difficult new problem in general is to manage the portfolios of several types of contracts.

Economic problems are also related to the risk inherent in the differences between the forecasted and realised future loads and prices. The load depends not only on the customers' load variation but also on the customers' existence as a customer in the future. The variability of energy price is strongly related to the total production, resulting in high prices during high load. Another major source for uncertainty and risks is the annual and seasonal variation in hydro power resources.

Also the technical challenges of managing load data are numerous. The customers come and go unevenly and the hourly metered data must be collected from various sources. One of the technical difficulties is to handle energy data coming from several, and often rather unreliable asynchronous data sources (remote metering, other operators, etc.) (Fig. 48).

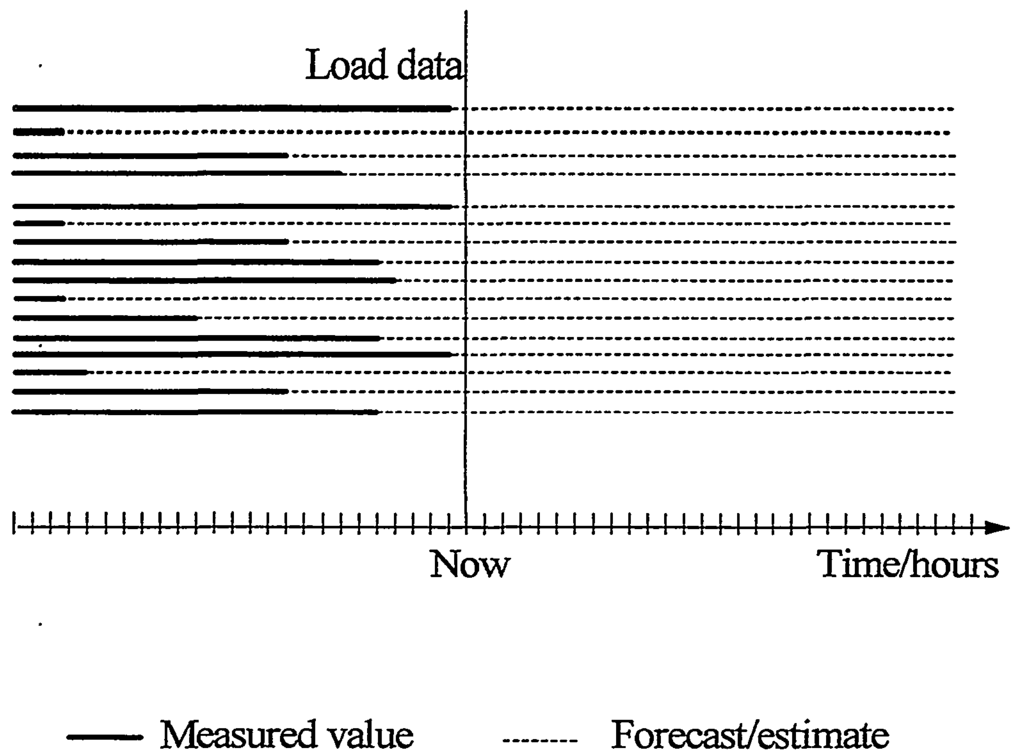


Fig. 48. The electricity market load data is available after various delays and the load data management must manage the situation by replacing missing meter readings by forecasts or estimates.

11.3 ENERGY MANAGEMENT IN THE FREE MARKET

The Estimation of Loads

There are over 100 distribution networks and currently about 100 energy suppliers. Among all of them the hourly energy data must be calculated to settle the balance between the participants. The Electricity Market Act specifies the general requirement to network owners and market partners to provide needed information to settle the hourly trades.

The knowledge of loads is essential for the trader's optimisation of power generation and electricity purchase. However, all the customer loads which participate in the competition are not metered by real time. The hourly demands are obtained only afterwards, on the next day or possibly after a delay of several weeks. When making estimates for the trader's entire power for the past hours there is available some on-line data from the network but the delayed load data must be substituted by forecasts until the actual meter readings arrive to the data management system.

Because customers also may change suppliers at any time the load forecasting must be done for individual loads and then the individual forecasts are aggregated according to the momentary contract positions (Fig. 49).

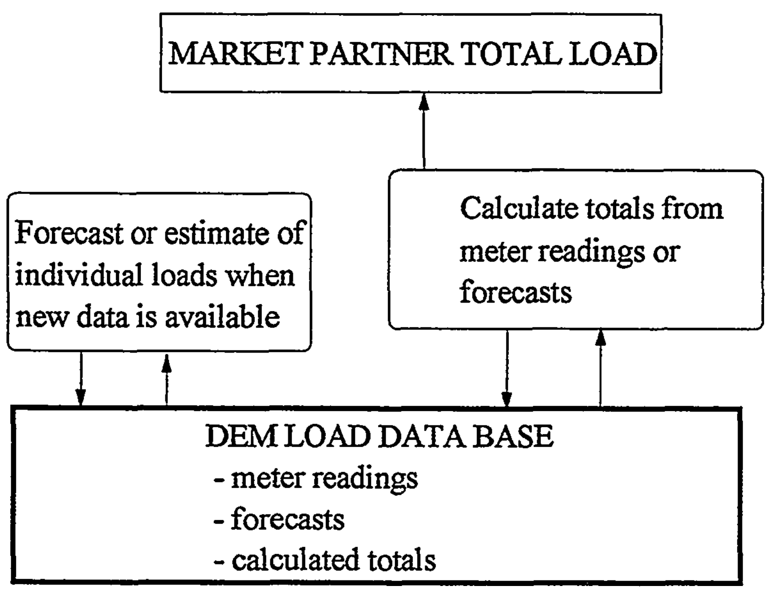


Fig. 49 . Forecasting and load estimation scheme fo the free electricity market.

Customer Class Load Estimation

In addition to the single customer loads and the system total load, quite many applications need data from customer class loads. Customer class loads can not be obtained by direct measurement, but using the data from the distribution network and load research, such application is integrated into the DEM system.

The estimation of customer class loads utilises the past recordings of the hourly loads, customer class load models and, if available, on-line measurements in the distribution network. As shown in Fig. 50, a typical example of on-line measurements are the loads of primary sub-stations and medium voltage feeders.

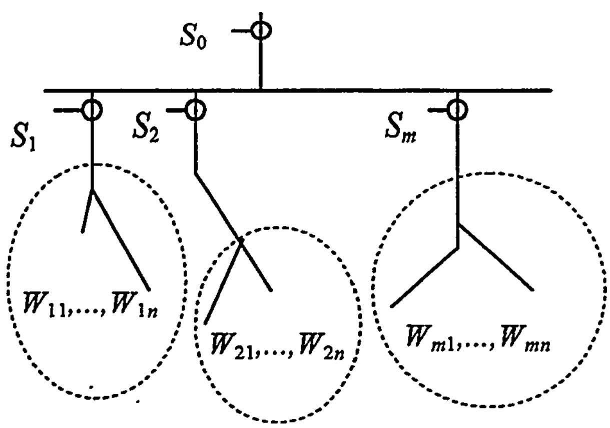


Fig. 50. The information needed for on-line load estimation of customer class loads includes the power measurements (S_0 ... S_m) at the substation and corresponding annual energies for different customer categories (W_{11}... W_{mn}).

An estimate for customer class loads can be calculated by combining the available measurement data with the load models. Such computations are most suitable to the network company, who has the access both to the network and to the customer related measurements /42/.

The Load Data Management Solution in DEM

The requirements of load data management are best met by an integration of two different types of information systems, the Supervisory Control and Data Acquisition (SCADA) and the Relational Database Management System (RDBMS). The on-line data is handled by a fast response SCADA system which can interact with several remote metering systems at intervals of a few seconds. The hourly data from the on-line system is stored to a RDBMS application where it is possible to handle meter readings, settled load values, forecasts, estimates and load models in a uniform manner for a large amount of objects and over a long time period (Fig. 51).

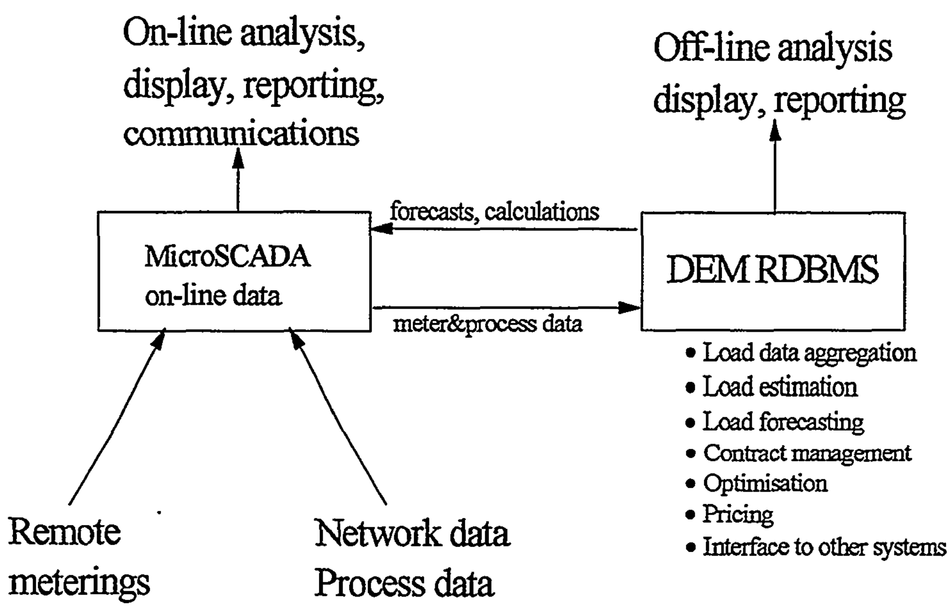


Fig. 51. The DEM system as it is implemented with the ABB MicroSCADA system.

The DEM system utilises the relational data model to store the time series objects. The time series objects are called Day-Time-Series (DTS). One DTS object stores one day's load data in addition to several versions of the data. The different versions are needed to store long, medium, short term forecasts, estimates and subsequent sets of revisions before the load is settled to it's final value. The ability to manage several versions of any DEM time series bring flexibility needed when estimating loads from several asynchronous data sources.

11.4 THE DEM SHORT TO MEDIUM TERM FORECASTING METHOD

The forecasting method is available to any time series in the DEM and the load calculations can easily benefit from the forecast where the actual measurement is not available.

A pilot system of DEM load data management is now running in two electric utilities.

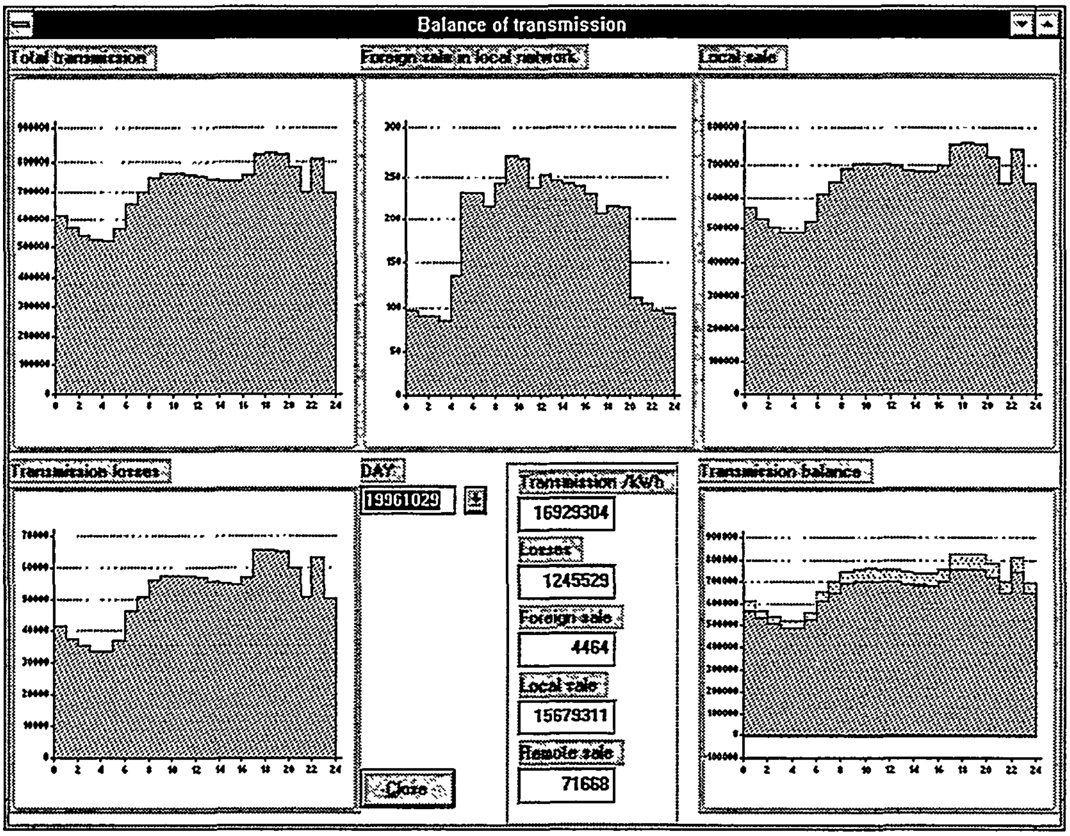


Fig. 52. An example of the graphical interface of the technical energy balance management function in the DEM system.

The Main Criteria for Forecasting

Several criteria were set up for a suitable forecasting method:

- It has to be of general use for all kinds of loads from single customer to groups of customers, without any mandatory user help or input. However an optional parameter-based control of the forecast process is an advantage.
- It has to be able to forecast using historical data of various lengths, maybe from only part of the time and with missing days and values. Likewise it has to be able to forecast for example one year ahead with only a minimum, for example one week, of historical data.
- It can't rely on the previous hours' and days' historical data, as the data in many cases wouldn't be available.
- It must be possible to forecast any load without previous knowledge of its behaviour, temperature dependency etc. From this follows the necessity for a dynamic outside temperature correction method requiring no user-controlled temperature dependency analysis in advance.
- It has to be possible to fully automate the forecasting, which means no obligatory user-controlled analyses as well as no parameter determinations.

- It has to be possible to forecast the past in a similar way as the future. Therefore the forecast may use only historical data ending the day before the forecasted day, and may not use later data even if it becomes available.
- An interactive mode of the forecast program is required in addition to the embedded, fully automated mode. It is essential to have a graphical display of results in the interactive mode. The DEM forecasting program's result display is shown in Figure 53.

The Forecasting Method

The DEM forecasting method developed is a modular time series approach, with detached on-line regression analysis and temperature correction. It is based on the assumption that most loads follow a similar day, week and year cycle.

The modular time series approach is based on using whole days as entities, the Day-Time-Series (DTS) format. Suitable comparison days are dynamically selected from the DEM historical database according to a day type and seasonal distance criteria.

The next step, regression analysis, is optional. It is done in regard to one regressor only. Temperature is recommended as the regressor, as in Finland it is the main factor for explaining load variation besides time dependency. Regression analysis is done separately for daytime and night-time, and then only on hours with similar load levels. If a high enough temperature correlation is found, the power values will be corrected to suit the forecasted regressor values. The forecasted value for a given hour is then the average of the comparison days' values for that same hour of day.

The DEM forecasting method is in pilot use in Turku Energia company. It is used to predict several electricity consumption related targets seven days ahead, but it is also used to predict the total consumption one year ahead for optimisation purposes. Several other types of targets have been tested and found to be quite predictable using the DEM forecasting method, including district heat - Figure 53 shows the forecasts and actual values of district heat for 15-28.2.1992 - and even EL-EX spot price.

Experience has shown this forecasting method to be satisfactory. However there is also some need for a short term adjustment when forecasting large loads only a few hours ahead. Because of the modular structure of DEM time series management such special needs are easy to add where needed.

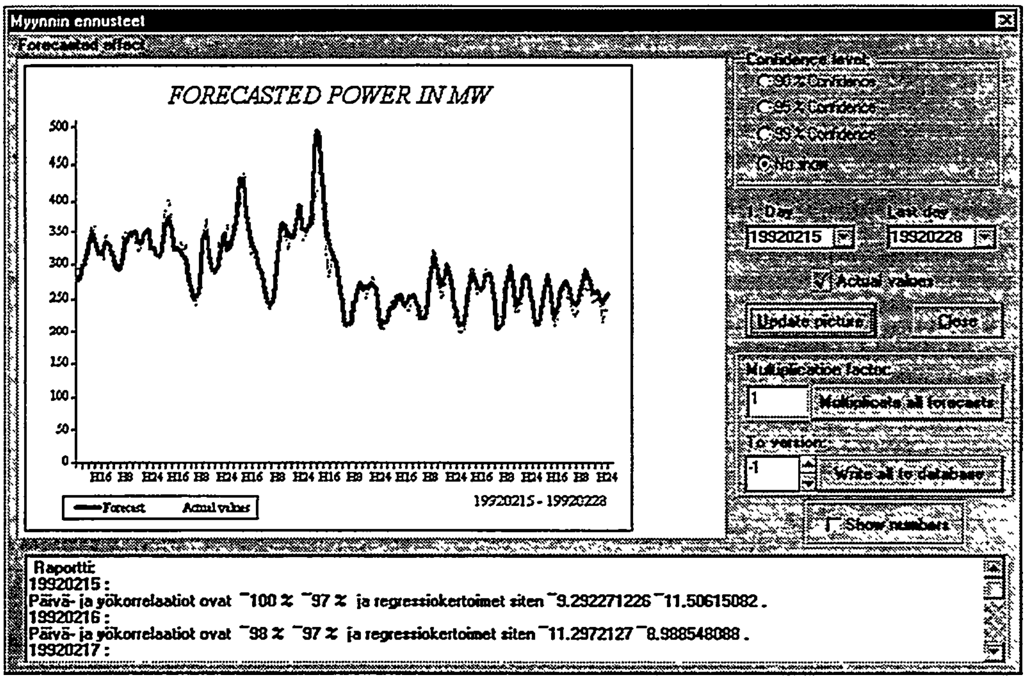


Fig. 53 . Result display of forecasting program in interactive mode. The forecast target is the district heat consumption of Turku Energia, and the time is 15-28.2.1992.

11.5 DEM Optimisation

General

DEM Optimisation is based on a mathematical method, which splits a given energy demand into its power components, so that the operational costs will be as low as possible. DEM application uses the optimisation subsystem in many different ways. Using the energy demand forecast, the optimisation gives a directive on how to produce and purchase the forecasted amount of energy. Taking the supplied hourly energy, the optimisation divides the amount to relocatable purchase components. The optimiser also can be used interactively as a planning tool, especially in the spot market trade.

There are some typical circumstances, where the results of DEM Optimisation are extremely valuable. In combined heat and power production systems it is quite a complicated task to decide, how to produce two different energy products with different demands in the same production units. Water reservoirs, heat storage and spot trade can be used separately to balance energy demand variations. DEM Optimisation is able to take into consideration all the influences together at the same time.

The Optimisation Problem

When the energy demand and production and purchase alternatives are known, the optimisation task is to determine, how to allocate production and purchase, which leads to minimum costs. The input data consist of energy demands, production and purchase alternatives and prices. The output data gives production and purchase dispatch divided into different components, and operational costs. Figure 54 is an example of a typical electricity production and purchase dispatch , where the normal load closely follows a given electricity demand, except for a certain amount of spot market trade which is more profitable.

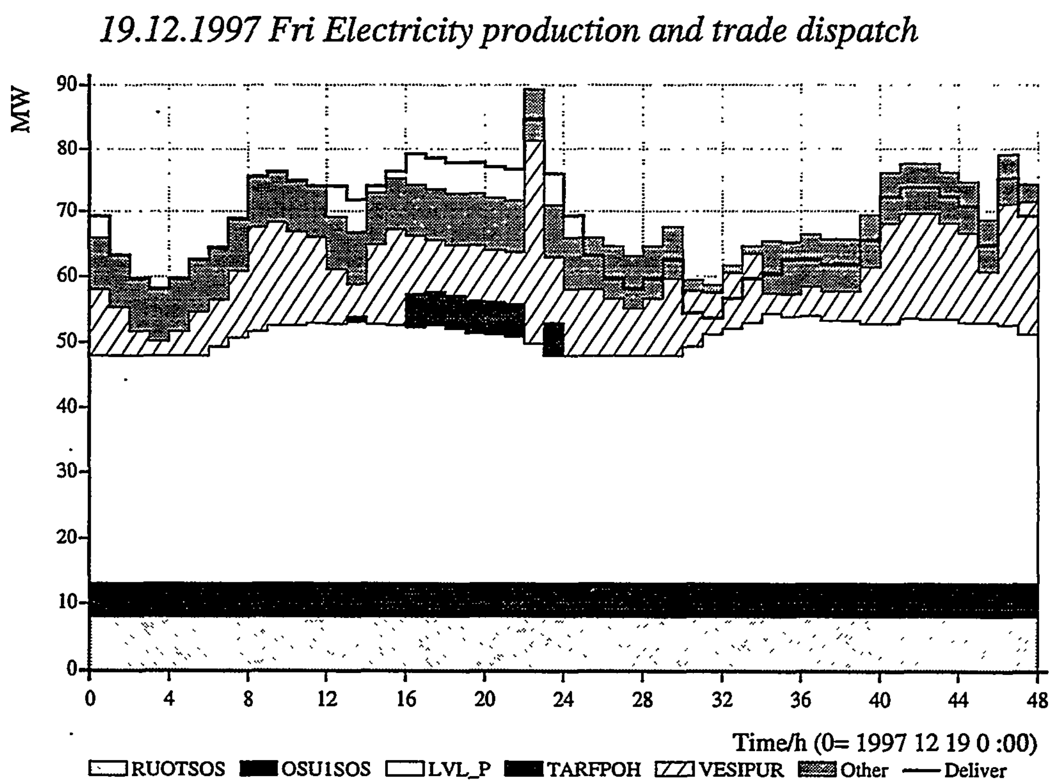


Fig. 54 . Optimal energy production and trade dispatch.

The Optimisation Method

The DEM Optimisation problem is formulated to the form of a Linear Programming (LP) model, which is solved optimally. The LP approach is selected, because it is easy to computerise and solve within reasonable running time, and the model is easy to understand and maintain; but its disadvantages might be inaccuracy in some situations and the inability to solve too complicated problems. Inaccuracy could be handled in many cases by including more details in the model. But if it is impossible to get the mathematically optimal result within an acceptable time, the method should be replaced by one, which searches only for " a reasonably good" solution instead of optimal.

Energy input alternatives are composed using the LP component library, which includes many different models for power plants, trade contracts and spot trade.

A basic part of the model is a static time point e.g. a one hour situation, which is supposed to be constant as related to official balance calculation. The model generation subprogram constructs the basic model to the dynamic LP structure, which consists of the time invariant basic part and the time dependent constraints and prices represented in the form of DEM Day Time Series (DTS) objects.

As a side product of the LP technique, the marginal costs of constraints are given as output data. These marginal prices can be used independently in spot trade and sales planning, but they also give important information concerning capacity constraints. A design tool for long term tariff purchase contract planning is based on this approach, and is available in DEM optimisation tools.

Use of the Optimisation

The required models are defined in the DEM installation phase. These models represent the energy production and purchase system. A model includes all available sources to purchase energy. A model generation is done by using the previously mentioned LP component library. Customising includes defining the values of parameters. Actual parameter values are maintained in DEM RDBMS, and a part of the data is time series data stored in the DEM data base as DTS objects, like energy demands, time of day prices and availability of power plants and other components.

As a background process, DEM Optimisation maintains a directive on how to produce and purchase the amount of energy demanded. This directive is based on the best available forecast of medium term (one year) and short term (one week) forecasts. The directive usually suggests some amount of spot trade based on forecasted spot prices, but if the user wants to contemplate the situation more carefully, the interactive mode is available.

The interactive usage mode includes some predefined optimisation tasks, which can be used to assist decision making:

- Annual planning and budgeting
- Long term purchase agreement planning
- Short term planning
- Spot trade planning
- Sales planning
- Afterwards evaluation

DEM Optimisation also produces additional information like production costs, marginal prices and key rations for business management assesments.

11.6 RETAIL SALES PRICING OF ELECTRICITY

Design of the sales tariffs for the retail customers is based on marginal production costs or forecasts of the market price. The output is then the minimum price that brings no income to cover the operational costs. Adding then the profit requirement together with the estimated customer load (which may include several distinct load points) an application seeks the best pricing scheme for the offering and compares it with the known competitors' prices (Fig. 55).

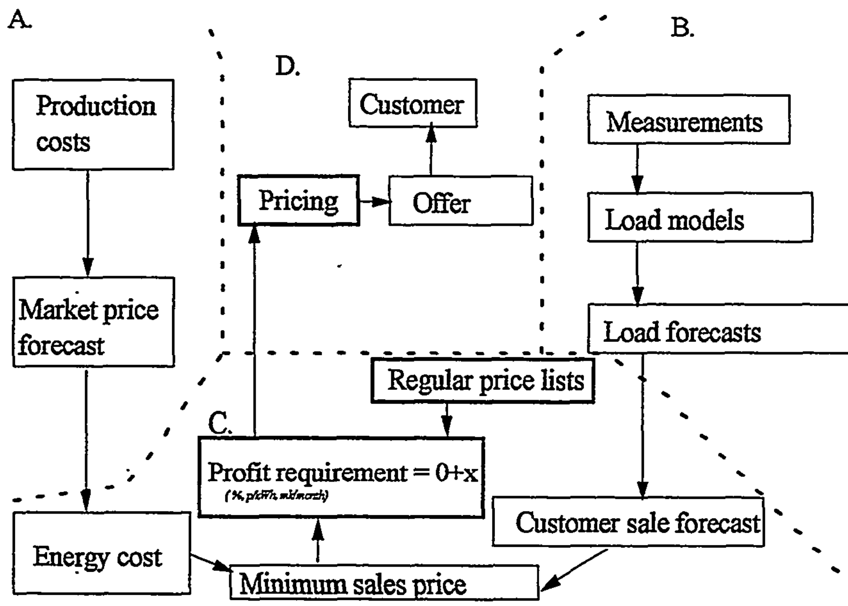


Fig. 55 . The process to define customer sale pricing with a given profit requirement.

11.7 CONTRACT SIMULATION AND RISK ANALYSIS

The free electricity market has brought with it new features and freedoms in trading electric energy. A utility's electricity sales can be nation-wide, with a fast changing total demand. Both the Finnish (EL-EX) and the Swedish-Norwegian (Nord Pool) electricity exchanges offer the utilities possibilities for short and medium term trades, buying and selling. Both the utility's power and price related risks are increasing, due to customer mobility and increased market options and possibilities.

A contract simulation and risk analysis concept has been developed in this respect. To get an overall picture of one's contract situation, power and price information of concerned contracts as well as market price are all compared on an hourly basis, as DEM day-time-series (DTS) objects. The concept features effective ways to achieve DTS-objects for different kinds of contracts and entities (energy and money) with relatively simple to use inputs, but dynamic and complex results. The main concept in contract portfolio assessment is described in Fig. 56.

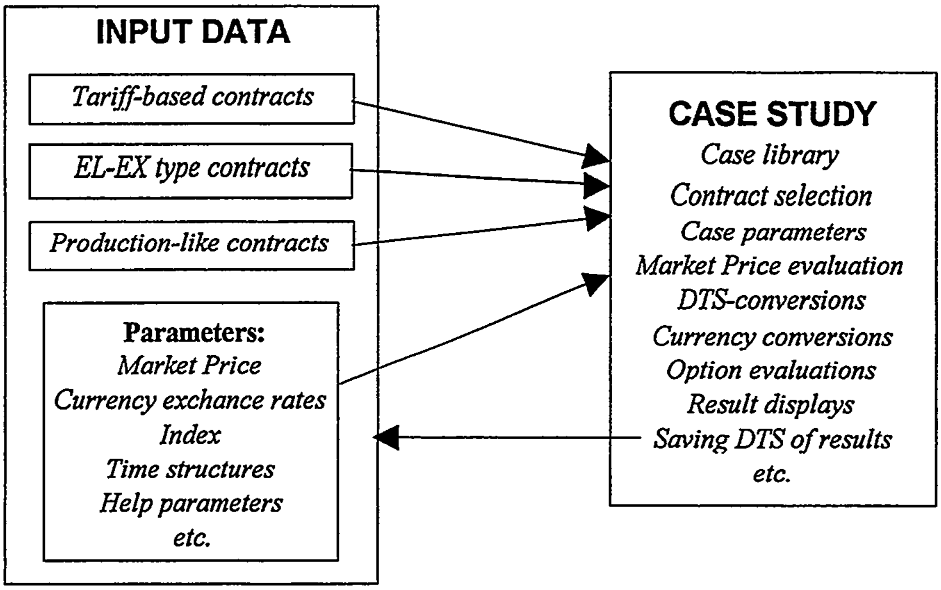


Fig. 56. The concept for risk analysis and contract portfolio assessment. The concept has two main sections: data input and case study.

There are four different types of data input, of which three are directly sale/purchase related:

- Week-based EL-EX-like contracts: Options or forwards, different currencies, workdays with the possibility to separate daytime from weekends and night time, freely chosen reference price for options etc.
- Tariff-based contracts: Different energy prices for different calendar times defined with an advanced time structure generator. Power constraints: either an option with maximum value, constant, load curve type or formulas which use parameters.
- Production-like contracts: Price need not be tariff like, it can also be a time series, constant or formula. Power input is equal to tariff-based contracts. DTS is a convenient way to get DEM optimisation results or forecasts to be utilised in the contract management concept.
- Parameters. The parameter is essential for the dynamic handling and creating of time series. The parameters can be time series or constants or formulas. And formulas can refer to parameters and time series.

A case study consists of choosing a group of contracts, buy and sell, and to calculate powers and prices for each to reflect the main parameter, the Market Price. Case study calculations include converting contract price and power information to DTS. The contract to time series (DTS) conversions include, among others currency conversions, option evaluations, and calculations of formula chains. The results are shown graphically or numerically as either single contracts or as groups, focusing on either costs or energies, and with different time aggregation levels. The concept includes management of different cases for more expedient analyses of different scenarios, making contract and risk assessments that much easier.

11.8 FUTURE RESEARCH

The original concept of DEM included functions listed in Table 10.

Table 10. The main functions of the DEM system for Distribution Energy Management.

1. *Electrical load estimation*
2. *Load forecast, short, medium, long term*
3. *Technical energy balance estimate (on-line)*
4. *Commercial energy balance management*
5. *Load metering management for billing*
6. *Selling / buying contract management*
7. *Monitoring and control of distributed generation*
8. *Electricity purchase optimisation*
9. *Pool price forecasting*
10. *Short-term (spot) electricity trade optimisation*
11. *Tariff design and retail sales planning*
12. *Load control optimisation, direct and indirect*
13. *DSM planning functions*

While most of these functions are have been studied already, in future research more emphasis should be put on functions 7, 12 and 13.

Monitoring and control of distributed generation: This function manages the remote metering and remote control of distributed, small scale generation. The types of power plants considered are wind generators, diesel generators and small hydro power plants. Also the generators owned by a third party can be monitored here.

Load control optimisation, both direct and indirect: The direct control primarily includes the control of electrical space heating, whereas the indirect control is based on the application of dynamic tariffs. For indirect control, this function includes both the design of the tariffs and the optimisation of their short-term and long-term use.

DSM planning functions, planning of demand side management activities beyond the direct and indirect load control: The data used for planning includes marginal purchase costs, load models for various customers and DSM impact models, for instance.

Table 11. The main interfaces of the DEM system to other computer systems and the other counterparts of the electricity trade.

1. *Metering systems*
2. *Substation SCADA*
3. *Distribution data management systems*
4. *Customer information system*
5. *Network automation systems*
6. *Distributed generation plants*
7. *Power pool*
8. *Brokers, generators, etc.*

In addition to the operational functions, an extensive selection of interfaces to other computer systems and other counterparts of the power trade will also be developed. These are listed in Table 11.

For the retail sales operation, the most important is the interface with the metering systems and with the substation telecontrol, or SCADA system. These interfaces produce the measurement based information, which is necessary mostly for load estimation and energy balance management. The role of the distribution data management system and network automation systems is to further increase the demand related information. The communication between these systems and the DEM system will be arranged on an hourly basis.

The customer information system also incorporates many functions and data necessary for the proper operation of the DEM-system. Among these are the metered hourly loads, energy consumption information for different customer groups and the basic data of the customers, including for instance the customer type and the tariff chosen and length of the power contracts.

11.9 SUMMARY

In the de-regulated electricity market, the power trading companies and transmission companies have to face new problems. The big challenges are caused by the uncertainty in energy prices and the load magnitudes. In order to minimise the risks in power purchase and also in retail sales, the power traders should have sufficient price information and an accurate estimates for the hourly demands of their customers as possible.

New tools have been developed for the distribution load estimation and for the management of energy balances of the trading companies. These tools are based on the flexible combination of the information available from several sources, like direct customer measurements, network measurements, load models and statistical data. These functions also serve as an information source for higher level activities of the electricity selling companies. These activities and the associated functions have been studied in the prototype system called DEM, which is now being developed for use by the Finnish utilities in the newly de-regulated power market.

12 DEVELOPMENT OF METHODS FOR DSM AND DISTRIBUTION AUTOMATION PLANNING

Seppo Kärkkäinen, VTT Energy, Veikko Kekkonen, VTT Energy and Pekka Rissanen Tietosavo Oy

12.1 THE AIM OF THE PROJECT

Demand-Side management (DSM) is usually an utility (or sometimes governmental) activity to designed to influence energy demand of customers (both level and load variation). It includes basic options like strategic conservation or load growth, peak clipping. Load shifting and fuel switching. Typical ways to realize DSM are direct load control, innovative tariffs, different types of campaign etc.

Restructuring of utility in Finland and increased competition in electricity market have had dramatic influence on the DSM. Traditional ways are impossible due to the conflicting interests of generation, network and supply business and increased competition between different actrors in the market. Costs and benefits of DSM are divided to different companies, and different type of utilities are interested only in those activities which are beneficial to them. On the other hand, due to the increased competition the suppliers are diversifying to different types of products and increasing number of customer services partly based on DSM are available.

The aim of this project was to develop and assess methods for DSM and distribution automation planning from the utility point of view. The methods were also applied to case studies at utilities.

12.2 DSM ANALYSIS AND DEVELOPED PLANNING TOOLS

The methods and tools developed in this project can be used in the analysis and simulation of different type of DSM activities, and assessing the costs and benefits of DSM programs or DSM based customer services. Methods were developed in co-operation with VTT Energy and Tietosavo Oy so that general structure and cost/benefit analysis system was developed in VTT Energy and distribution network related tools in Tietosavo Oy. Both developed systems can be used individually although most comprehensive studies can be carried out by using both tools.

Figure 57 gives the general structure of DSM planning and the role of the tools in the procedure. Network model described in the figure is actually a very large development environment for decision support in distribution system planning and it is.described more detail later in Figure 59.

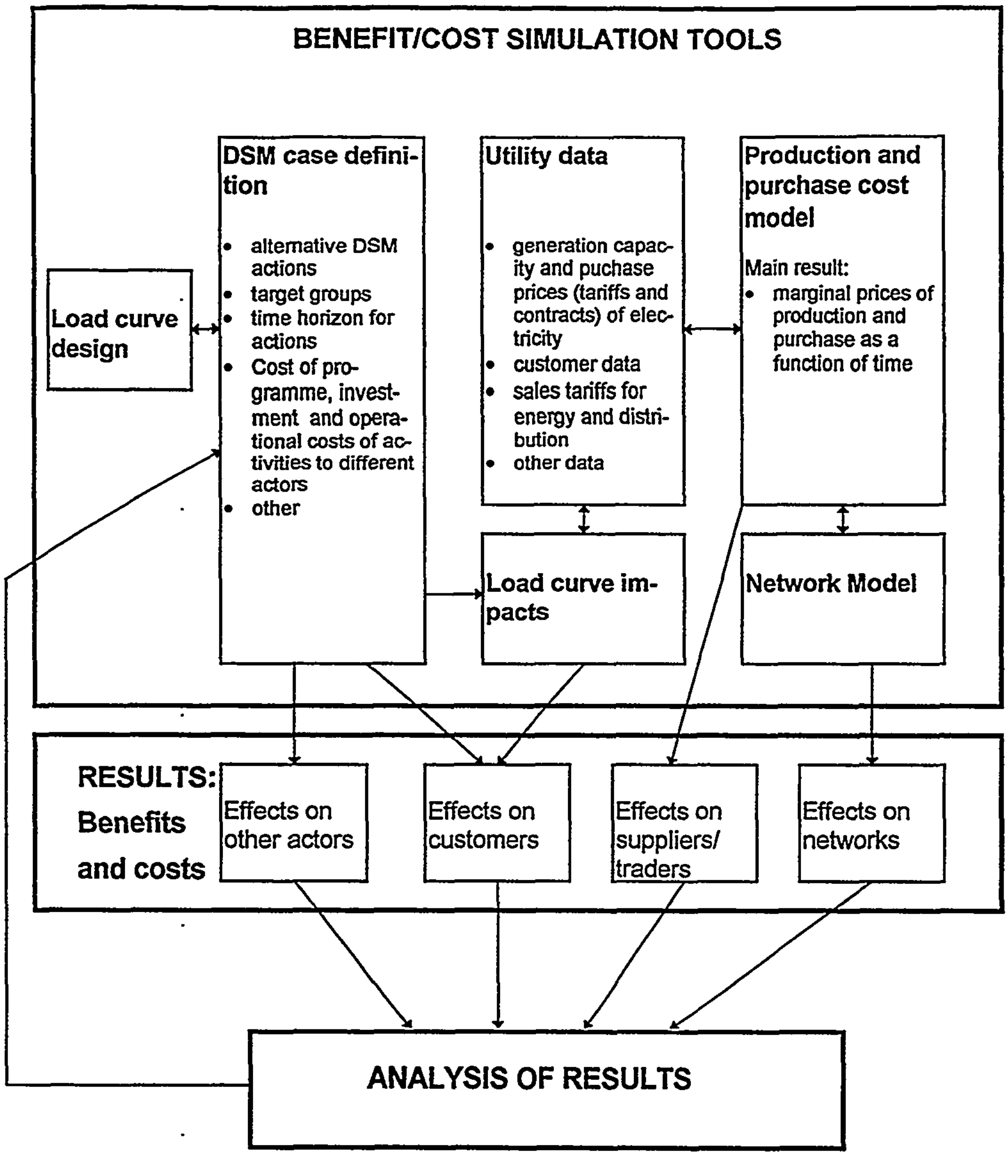


Fig. 57. Interactions between planning tools in DSM analysis.

12.3 BENEFIT/COST SIMULATION

12.3.1 General procedure

A developed and computerised Benefit/Cost Analysis Method reviews to a given DSM project, and calculates, which financial benefits or costs are to be detected for different levels of participating sectors. A given DSM project may include one or more DSM activities. A DSM activity is defined in terms of this planning method as a change of total load curve impacted by DSM functions, applying for ex. electricity saving appliances, and as a distribution of investment costs between perspectives involved.

The volume of DSM project is freely scaleable, and it can be focused to certain parts of network or to the whole area of electricity company, and it can be focused to any customer class or their combination.

The electricity company is defined as its total load curve, the profile of purchase and production costs, retail energy tariffs and retail distribution tariffs.

The Benefit/Cost Analysis will be done like a simulation calculation. A given DSM project will be computed, and impacts will be given as results. The adapted simulation algorithm is quite accurate, a calculation is done for the whole year using one hour time step in order to get the peak load impacts as precise as possible. A typical analysis includes results for the first year, for the most intensive year and an estimation for the whole life cycle of the DSM project.

All this mess demands a lot of input data. Thus the data management and user interface is done by using MS Access Data Base development system. The proper simulation is processed by c-language program, which is based on an extensive function library just developed for the DSM simulation purposes.

The Benefit/Cost Analysis tool has been used for the analysis of some special DSM technologies, like advanced illumination, hot water accumulators, sauna stoves etc. It has been found rather difficult to discover a DSM technology, which will be profitable to all participated levels. Mostly they may be cost effective just to the customers but unprofitable to the sales and transmission companies or vice versa.

12.3.2 Load difference curve planning

To maintain input data to the Benefit/Cost Analysis system a Load Curve Planning tool was developed. This method formulates and reshapes load curves, which represent the demand differences between normal load and DSM impacted load. An idea is to utilise the shortage of available information and refine it to the form of detailed index series.

The format of load difference curve is the one, which is traditionally used in the field of load research, the two week index series. In this representation the year is divided into 26 two weeks periods, which include $3 \cdot 24$ h values, one for workdays, the second for eve day and the third for holy day. This relative index series is scaled so that multiplying a value by annual energy consumption (MWh) the hour base average effect (kW) will be given. Figure 58 presents an example of a DSM related load difference curve as an index series.

Change to hot water accumulator

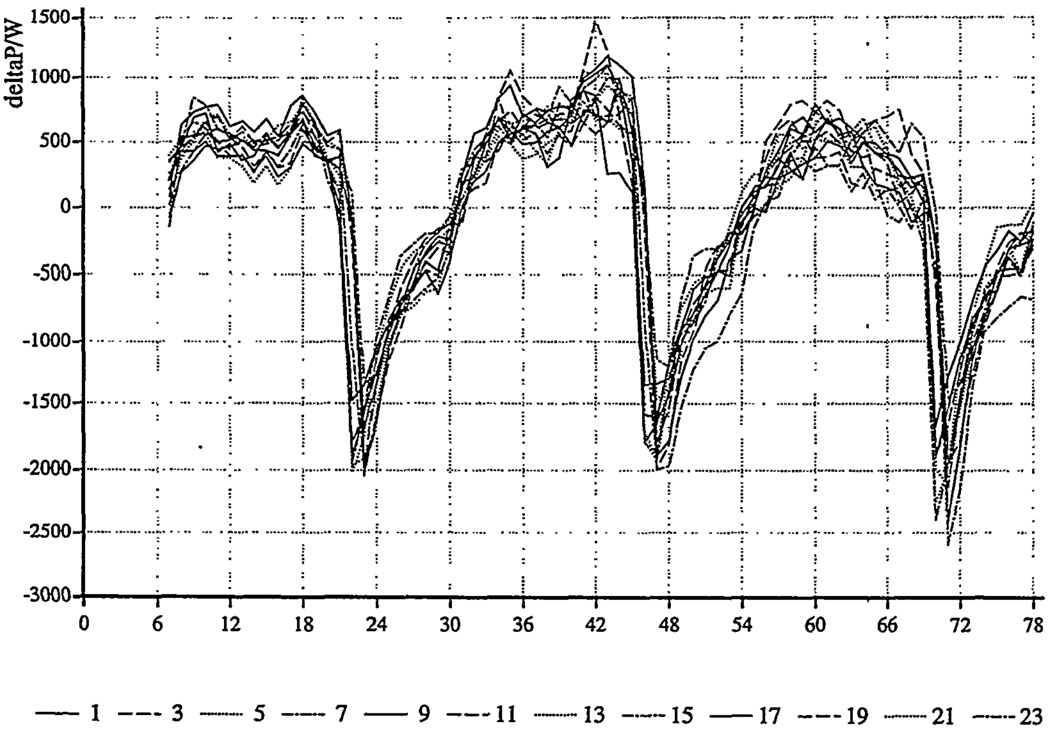


Fig. 58. A DSM load difference index series, presented in watts per applience.

The tool is implemented using APL programming language, which is developed for easy processing of vectors and matrices. This tool utilises the results of Finnish load research as a collection of load curves for most characteristic consumer types, which can be loaded to basic data. The data can be modified by using APL-functions, which reshape, rescale, combine, cut, copy and paste index series as desired.

Index series produced by this planning tool can be directly used as input data to the Benefit/Cost Analysis and Network Planning Tool. Contemporary the Benefit/Cost Analysis itself can produce combined index series, where several DSM-activities are combined to areal and customer class distributions.

12.4 DEVELOPMENT ENVIRONMENT FOR DECISION SUPPORT IN POWER DISTRIBUTION SYSTEM PLANNING

12.4.1 Introduction

The first versions of the DSM methods are developed and implemented for power distribution system. Different methods for estimating profitability of the distribution automation and communication technologies are developed parallel.

Tietosavo Oy is a software house producing systems for the Finnish power distribution companies. In this project we have worked in cooperation with Tietosavo Oy's customers Pohjois-Karjalan Sähkö Oy and Savon Voima Oy.

12.4.2 Objectives

The purpose of this part of the project is to create environment for different planning methods in power distribution. Different investment plans must be set side by side and the best combination of the plans will be selected. Eventually this environment will be expanded to support the Integrated Distribution Planning in the power distribution utilities.

On the other hand the methods will be developed and applied for practical purposes in power distribution utilities. The development of calculation methods for DSM-options is the most important area of this project.

12.4.3 Environment

Different databases and planning practices create the basic environment for the decision support. Figure 59 represents the basic connections in this setting. In the following the development work for different areas are briefly summarized.

Schedule of implemented investments

Estimated and realized costs with all necessary classification data are collected in a database called Scheduled investment projects. This database was updated in Pohjois-Karjalan Sähkö Oy about two years.

From this database we have performed an Access-database for different classification purposes. Using normal database operations the planner can see the real investment flow of the last years and estimation for the next year.

For further classification and optimization purposes we made a small neural network application. From the database the planner can filter appropriate data for the teaching algorithm. In this first prototype we used Kohonen's algorithm for unsupervised competitive learning. Here we must proceed carefully because the useful time span is still reasonably short.

During the last two years this environment is changed radically. The investments are in the relational database at the moment. For further purposes whole the production control system including much more details than the basic system of the investment schedule can be used.

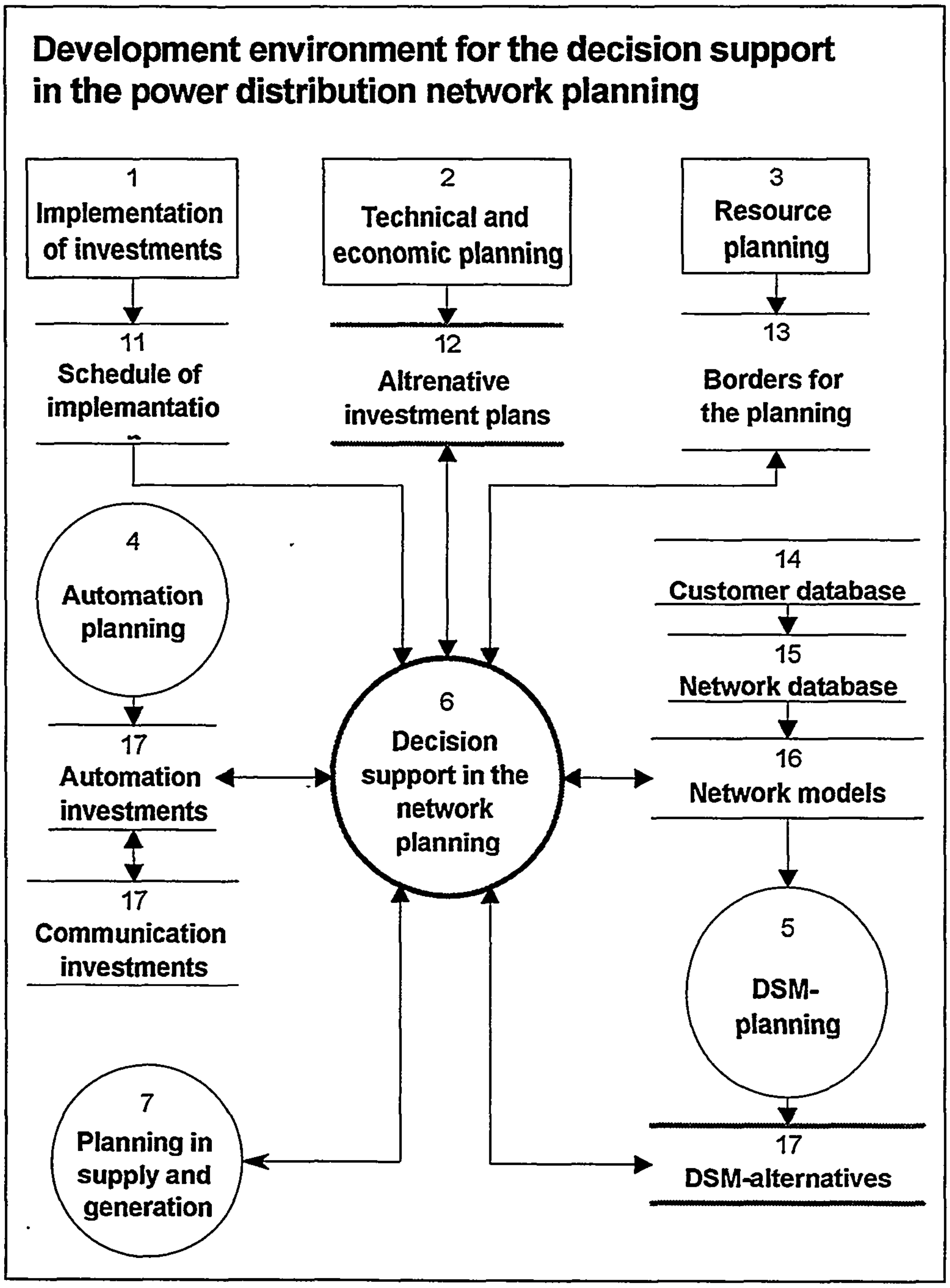


Fig. 59. Basic connections between different parts in the planning process of a distribution company.

Network models

The customer database and power distribution network database form the basis for different planning purposes. These databases are very large. When we must control, for example, the whole distribution system, it requires data collection from databases and being included it in the **network models**.

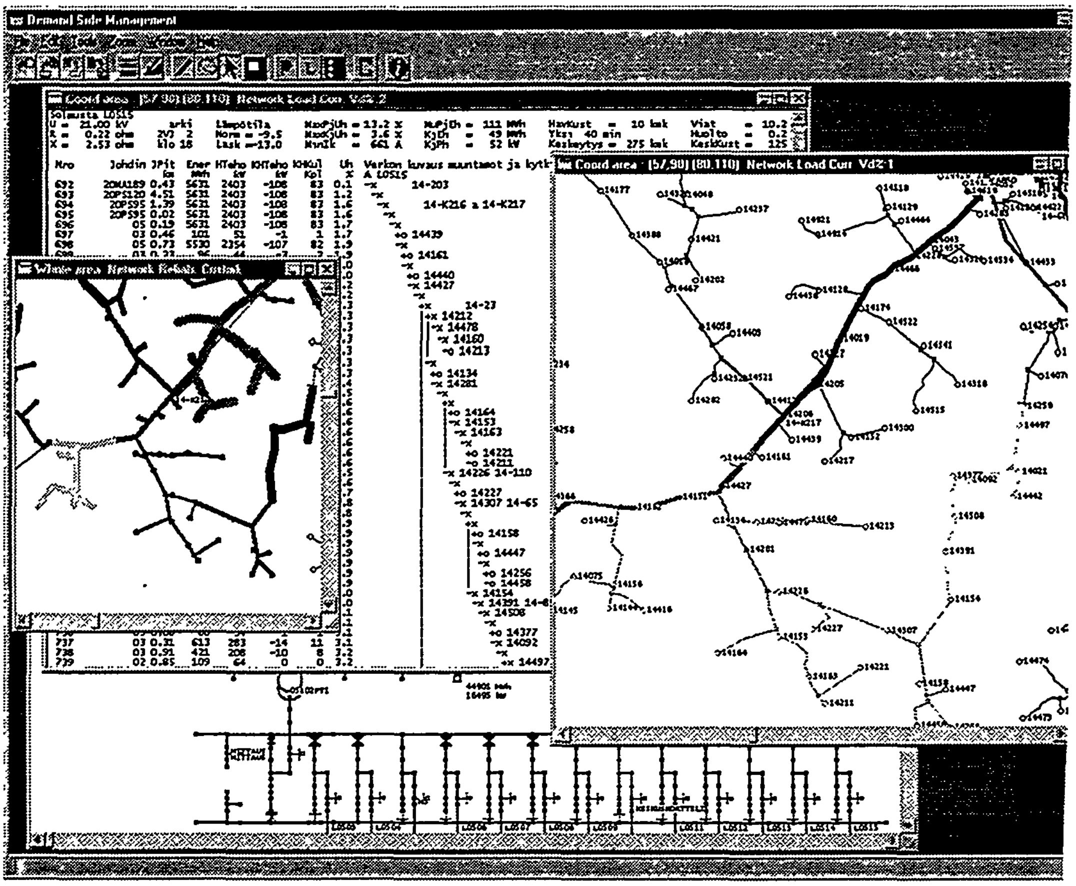


Fig. 60. Displays for the network section model, network model and power station model. The numerical details of the calculations can be followed from parallel views.

In this environment we have used the **network section model** which serves the DSM-planning and the distribution network automation planning. The basis for this model is in reliability calculations where the network is divided into fault sections. The circuit breakers divide the distribution network into sections. The load curves and consumption of customers are collected in the sections. The distribution network in the section is modeled as an equivalent network if needed.

At the moment network calculations seems to be fast enough so that equivalent network calculation is not necessary. Calculations are performed using a real medium voltage network and the section model is used only for the reliability calculations and hiding details of the network display.

This model can be used when we want to see the consequences of different DSM-plans in the distribution network. In cooperation with the technical and economic planning system we are going to develop decision support methods by witch we can select the best combination of DSM- and distribution system investments.

A prototype of network model and network section model is programmed in C++ language and the connections to the databases are implemented using ODBC-interface. Formerly medium voltage network calculations including reliability calculations were programmed in these models.

User interfaces

Figure 60 describes the basic display for the network calculations. Here is an example of network section model and medium voltage distribution network model.

These displays we can use for optimization varying, for example, switching and out door temperature. Here we can see the technical result: voltage drops, protection situation in faults and estimated outage cost. The colors and the widths of lines give quick information of current calculations.

For DSM-planning the calculation of the loads is performed for every hour of the year. So we can display, for example, the peek power of a certain point or sum of points in a power distribution network. From these displays we can see the worst times of the year and from a different list we can see what kind of consumption there is.

The details of hourly power calculation results can also be used for other application purposes (Figure 61). Calculating the selected network with and without the DSM-options we can see the differences, for example, in peak powers. So we can select the most appropriate DSM-methods for these loads and this distribution system.

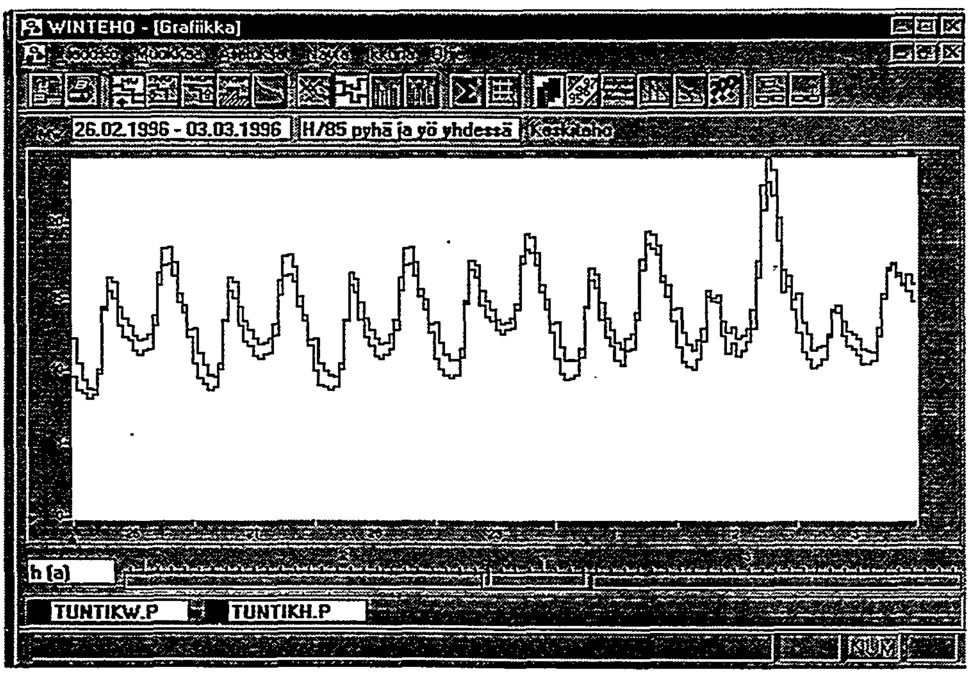


Fig. 61. Medium peak powers of a week from Monday to Sunday on a certain distribution area with and without the DSM-option. The load change curve is in Fig 60.

These knowledge we can use when we decide where and for which consumption the DSM-efforts should be focused. After applying some DSM-option for certain consumption group on certain distribution area we can estimate the impact in power demand.

The temperature correction for the load curves is applied in the calculations. This is important in electrically heated areas. Using estimated temperatures we can see the impacts of a DSM-option on that kind of peak time.

DSM-calculation in power distribution network

The impact of a DSM-option for a certain load type is calculated creating first the basic **load change curve** for this option and this load type. Then we estimate the yearly average change in energy consumption for this type of customer. After that the change in power is calculated in the same way as the power from the normal load curve. The deviation for the load change is expected zero. The load change curve may have negative values too, which means load shifting.

Table 12. The impacts of DSM-options to certain customer types (load types). An example.

Microsoft Access - DSM-options : Table

OptionName	LoadType	ChCurFile	ChEnerMWh	Penet%1	Penet%2	Penet%3	Penet%[illegible]
Water Heating (Reserve)	7	whres	2.6	50	80	80	80
Water Heating (Continuos)	10	whcont	2.6	50	100	100	100
Filament Bulb Change	23	bulbch	0.5	100	100	100	100
Sauna Heater (Continuos)	7	sauna	3	20	40	60	80

In Table 12 there are some examples of DSM-options for different load types. This table includes the most important values for DSM-options. LoadType-column tells the customer group for which the option is focused. ChCurFile-column includes the change load curve file used. ChEnerMWh-column includes the yearly energy change for one customer. The last columns include the penetration factors for the next years. These values estimate the speed of the DSM-option applied in this customer group.

In this way we can estimate and compare the DSM-options with the investment in power distribution system. Can we avoid some investment or only postpone the investments some years selecting first the DSM-investment?

The DSM-option for a certain customer will be managed on its own way. It is possible to create a load change curve for a DSM-option and use this for a certain customer. Individual load change methods will be developed if needed.

DSM-planning

Savon Voima Oy is applied as a DSM case-project whose purpose is to avoid network investments for a certain distribution area. The results of this case-project, together with other DSM case-projects in Finnish power distribution companies, will be a focus for the development work of the models.

First we have defined an interface between power distribution network planning and DSM-planning. From network planning we estimate the area where the DSM-actions should be focused. What kind of consumption is there and how much of that consumption should be moved or saved? Further we must estimate the value of the investments, which should be avoided or postponed.

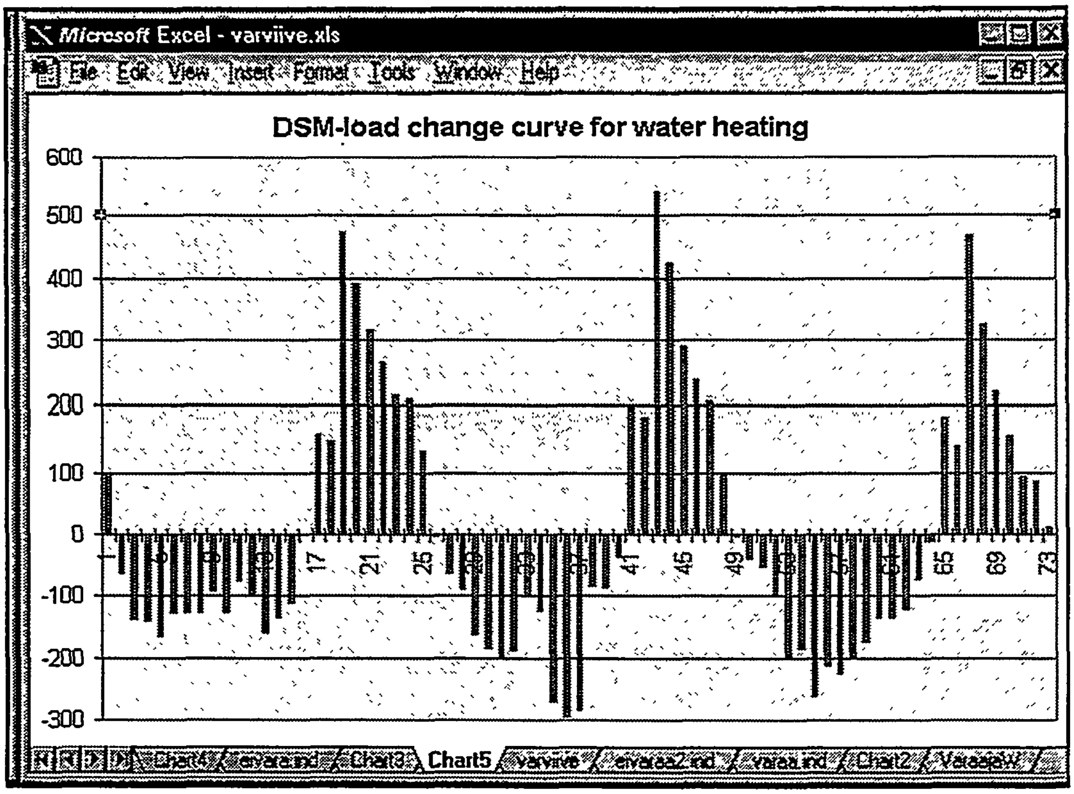


Fig. 62. Load curve changing hourly indexes for different day types. 2/3 of the heating power is delayed two hours at 11 PM.

Within these limits DSM-planning tries to select the best combination of actions, which promote the needs of the distribution network planning. At the same time the DSM-planner must consider the other impacts of the planned actions. What is the impact on power production and what is the value of possible incentives for these actions? Furthermore, what does it means to the consumers?

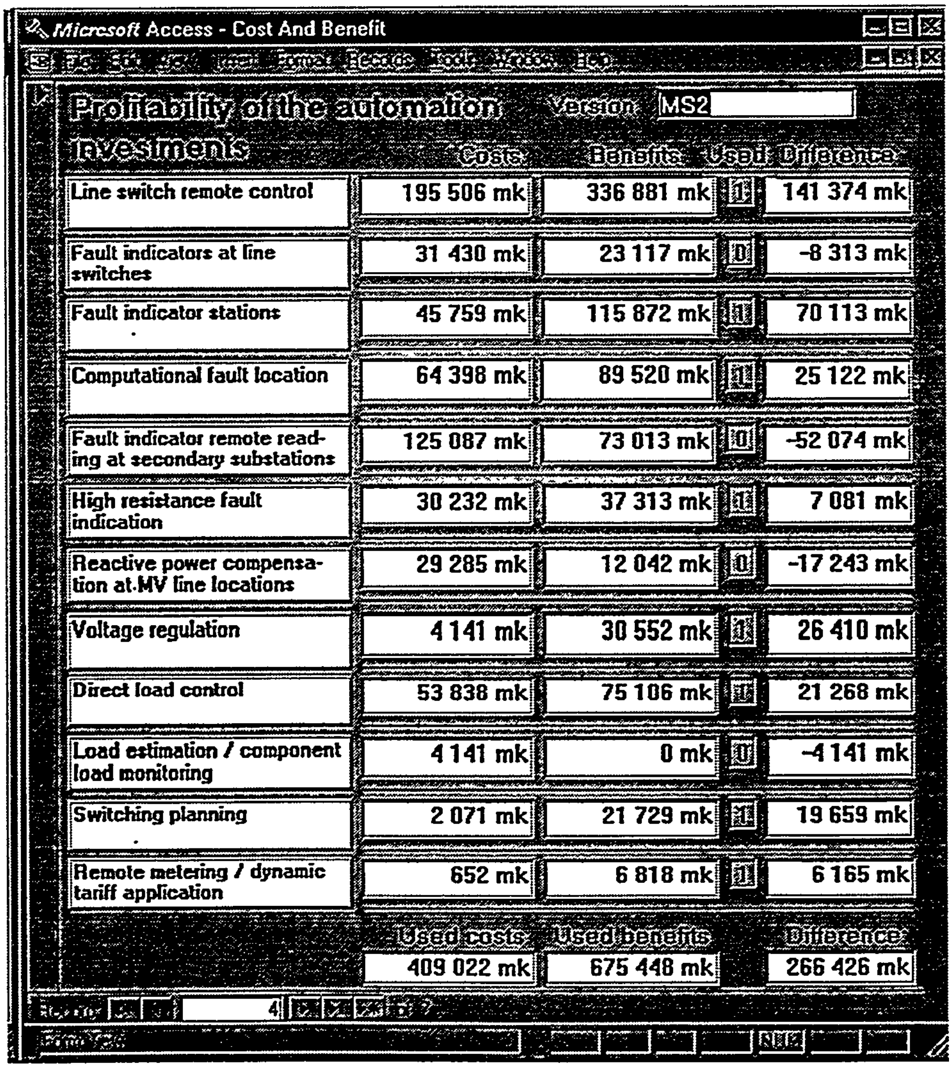
After the DSM-planning we can define the impacts for different load curves and how much of the required needs we have reached by planned DSM-actions.

The results come back to the network planning and we can add the load curve changes in network planning. The network will be calculated using these new load curve changes. This result is then basis for the investments in power distribution network or we can define new goals for the DSM-planning and start the interaction again.

In Figure 62. is an example of load curve change. This change will be added to the customers in focus. From the network calculation displays in Fig. 60 we can see the impacts for the power distribution system.

Automation planning

Profitability calculations for different Distribution Automation systems have been designed in the EDISON-project. The returns from the investments in automation have been programmed in ACCESS-database model as seen in Figure 63.



Investments	Costs	Benefits	Used	Difference
Line switch remote control	195 506 mk	336 881 mk	1	141 374 mk
Fault indicators at line switches	31 430 mk	23 117 mk	0	-8 313 mk
Fault indicator stations	45 759 mk	115 872 mk	1	70 113 mk
Computational fault location	64 398 mk	89 520 mk	1	25 122 mk
Fault indicator remote reading at secondary substations	125 087 mk	73 013 mk	0	-52 074 mk
High resistance fault indication	30 232 mk	37 313 mk	1	7 081 mk
Reactive power compensation at MV line locations	29 285 mk	12 042 mk	0	-17 243 mk
Voltage regulation	4 141 mk	30 552 mk	1	26 410 mk
Direct load control	53 838 mk	75 106 mk	1	21 268 mk
Load estimation / component load monitoring	4 141 mk	0 mk	0	-4 141 mk
Switching planning	2 071 mk	21 729 mk	1	19 659 mk
Remote metering / dynamic tariff application	652 mk	6 818 mk	1	6 165 mk
	Used costs	Used benefits		Difference
	409 022 mk	675 448 mk		266 426 mk

Fig. 63. An example of the assessment of distribution automation investment.

The basic data of the network will be accessed from the databases of the distribution utility. The network section model will be used suitable. Finally the profits of these investments will be compared with other investments' profits.

Communication planning for DSM

In this project we have followed the development of communication investments defining project in IEA-project (Annex II). These investments are important to the automation and DSM-options. The investments will be partly overlapping.

The present values of the costs and benefits of DSM- and the communication investments will be added to the automation investments considering the overlapping.

Conclusions and further development

The DSM-investments are difficult to make profitable without incentives at the moment. In straining economic environment the DSM-investments will become useful alternatives in cooperation with other investments.

The previous pilot models and prototypes create the basis for the future application development. The final decision support system will include parts from the different planning environments of the power distribution utility. Independent applications for different purposes will then be performed to collect data from planning areas and balance the plans.

13 COMMUNICATION TECHNOLOGIES FOR DEMAND SIDE MANAGEMENT

Pentti Uuspää, VTT Energy

13.1 SCOPE

The scope of this research is data communications for electric utilities, specifically for the purposes of Demand Side Management (DSM).

Demand Side Management has the objective to change the customer's end use of energy in a manner that benefits both the customer and the utility. For example, peak demand may be reduced, and the peak demand may be relocated to off peak periods. Thus additional investments in generation and network may be avoided.

A number of Demand Side Management functions can be implemented if a communication system is available between the Electric Utility and the Customer. The total communication capacity that is needed, will depend on several factors, such as the functions that are chosen for DSM, and on the number and type of customers. Some functions may be handled with one-way communications, while some other functions need to have two-way communication.

13.2 CUSTOMER/UTILITY FUNCTIONAL NEEDS AND COMMUNICATION TECHNOLOGIES

For the DSM-related functions, the functional needs of the electric utilities have been investigated in ten participating countries. The approach has been to collect the information using a questionnaire that was sent to Utilities, and then combining the responses obtained.

There are about one hundred utilities in Finland in 1997. The number has been gradually decreasing over the last few years.

Ten utilities in Finland were asked to respond. These utilities represent various types of utilities. Each one of them has a different size, location, and customer mix. Some of them were serving urban areas, and some of them rural areas.

Data collection has been carried out in each one of the participating countries in a corresponding manner.

To justify the cost of a communications system between the Utility and the Customer, one may consider all of the potential communications needs for DSM, and to check whether these could be included, and handled by the communications system being planned.

Some of the electric utilities are actually energy utilities that deal with other products and services besides electricity. Communications needs for the other services should also be assessed. These other services were included in the questionnaire.

Combining the data communications needs of electric utilities with those of other utilities such as gas and water utilities, has also been considered. So far these combinations are not common in practice. In the future, Automated Meter Reading of gas, water, and heat meters is foreseen. Common communication standards could be useful for several utilities.

The communication functions of an electric utility may also be combined with a selection of other telecommunications services for households. Some electric utilities have bought cable television networks and may be able to communicate various types of messages, as well as to provide home entertainment to their customers through a cable television channel also.

The communications services, that are needed, could be offered by the utility or by a company controlled by the electric utility. A very natural choice can also be an outside telecommunications company acting as a partner to the electric utility.

An inventory of the communications technologies has been made. This survey includes systems that are being used in prototype experiments, and also systems used in full-scale installations in the field.

13.3 DEVELOPMENT AND ANALYSIS OF CUSTOMER/UTILITY FUNCTIONAL NEED AND COMMUNICATION TECHNOLOGY SCENARIOS

When the functional needs of DSM and other possible associated services are known, one can define the message sizes and determine how often the messages would be sent when these functions are implemented. From message size and frequency, the average data rates required to support these functions can be calculated. Data rate requirements can be compared with the capacities of the channels, that may be based on one or several communications technologies. For the several possible communications technologies, the feasibility of implementing a selection of DSM functions can be investigated.

Penetration of a function is another variable parameter to be considered. Penetration means the percentage, from zero to hundred, that describes how large a fraction of a given customer group has chosen to have a particular function implemented. Penetration is considered in the range from a previously defined minimum to a maximum. Here maximum refers to the ultimate number of users of a given function. The maximum percentage is chosen in a manner that represents the estimated willingness of the customers to choose a given service. One may vary the percentage value of penetration in a stepwise manner, and examine how the data rates are affected.

The technologies considered, include Power Line Carrier (PLC) or Distribution Line Carrier (DLC), Telephone or other cable connection, Cable TV (CATV) and Radio. Several combinations of these technologies are possible too.

Hierarchically, one can divide the communication task into two layers, and choose a technology for each layer independently. Also within one layer, reasons may arise for adopting communication systems with several technologies. Then each technology will reach a part of the customers. The various technologies chosen, will carry part of the data communication load in a parallel fashion.

Communication systems may be designed with one-way or two-way communication. One-way communication can be used, for example, when an electrical company wishes to tell the customer information about electricity prices or other useful advice about electricity. Some of the more advanced DSM functions require two way communication. With a two way communication system, the customer can respond and customer data can be collected.

13.4 STANDARDS

There are communications standards specifically for electrical power applications.

There are also commonly used communications standards that can be useful for many applications. Some of these general purpose standards will also be used for the electric power applications.

An inventory has been made of standardization working groups, their current topics, and participating persons in each country.

Standardization takes place in working groups that consist of experts in the subject matter. These working groups produce the material for the standard proposals. Formally, international standards are confirmed by international standard bodies. International Electrotechnical Commission (IEC) is important in the electrotechnical field. Also, the European standardization activities within CENELEC and CEN are being observed.

Standards are sought for Meter Reading and Data Processing of electrical energy and electrical power. Meter reading is also needed in the gas and water utilities. To save effort, meter reading standards that can be used for several commodities, that is, for electricity, gas, and water, may be developed in the future.

There is an interest to try to affect the standardization process in such a manner that standardization would benefit from the findings of the current Communications Technologies research project. Creating good standards takes time. It is generally felt that standardization is a fairly slowly moving activity. Starting a new standardization work item with a good draft document can make the standardization process to make faster progress.

13.5 PRIORITIES FOR FUTURE RESEARCH

Topics for future research have been investigated. New emerging communications technologies and services, such as some form of the Information Superhighway, have attracted interest.

There are numerous new technologies within communications that have been presented recently. The ones that are likely to survive, are becoming more common in many application areas. Thus Electrical Utilities are likely to choose the communications media that will reach a large number of the customers, and especially the domestic households, in the future.

Two new topics for further research have been chosen. A project plan has been made.

13.6 TECHNICAL EVALUATION AND COSTING MODEL

A data communications needs, functions, and technologies model for technical evaluation of the communication systems has been developed. The model has been implemented on a personal computer. This model is intended to be used for communication system investigations in each participating country.

A model that allows examining also the cost of communications systems for electric power company and demand side management purposes, has been developed. The cost evaluation is done from the data that the technical evaluation model has generated.

The costing model should make it possible to assess the economic aspects of various communication systems. Thus the economic feasibility can be assessed, and the cost of systems can be compared.

The scope of each study or each scenario is the geographic area supplied by one primary substation.

The network properties can be entered and stored in a data base. The data consists of the sizes of secondary substations as well as customer types and subtypes. The secondary substations can be populated with the various customer types either manually or automatically.

The communications technologies to be used, will be attached to the network structure that has just been created.

The functions of demand-side management can be chosen. For each customer group and for each communication technology, the relative volume of functions, that is, the share of customers that have this particular function, can be chosen.

The software has been tested as a beta version, and the comments and recommendations that come out of this testing process have been used for the final version.

The results of the calculations consist of the data rates in bits per day, both upstream and downstream in the network tree. The data rates are calculated for the segment between the primary substation and the secondary substation, and also for the segments between the secondary substation and the customer.

The model can be used to evaluate and to assess the communications systems that are planned or that are currently in use.

A communication system can be built over a time period of many years. The model makes it possible to define the annual investment plan of the communication system and to calculate the total costs.

Case studies have been done in four countries to study the feasibility of the software. These countries are Japan, Spain, France and Norway.

Applicability of the communications model in a case study in Finland is also being investigated.

13.7 FURTHER RESEARCH

Topics for further research and development have been surveyed with the questionnaire. Based on this questionnaire and the present project, two project plans have been made: Development of customer gateway specification, and Strategies for narrowband to wideband communication media migration.

Also within Annex II, requirements have been identified for DSM, Energy Efficiency and related functions in several countries.

The objectives of the Customer gateway specification are to define preferred packages of functions for demand-side management, Energy Efficiency, and related functions, communication media, and operational protocols and hence to specify one or more forms of standard customer equipment.

The objectives of the Strategies for narrowband to wideband communication media integration are to investigate the wideband communication penetration, identify the most probable routes to providing wideband channels to customers, and the time scales. The requirements and costs of carrying out fairly low data rate functions, using wideband one way and two way communication channels will be investigated.

Note: This research is a Finnish part in an international research project on Demand Side Management, with ten participating countries under an International Energy Agency (IEA) Implementing Agreement on Communications Technologies for Demand Side Management, Annex 2. The Operating Agent is EA Technology in Chester, the United Kingdom. The ten participating countries are: Australia, Finland, France, Italy, Japan, the Netherlands, Norway, Spain, Switzerland, and the United Kingdom.

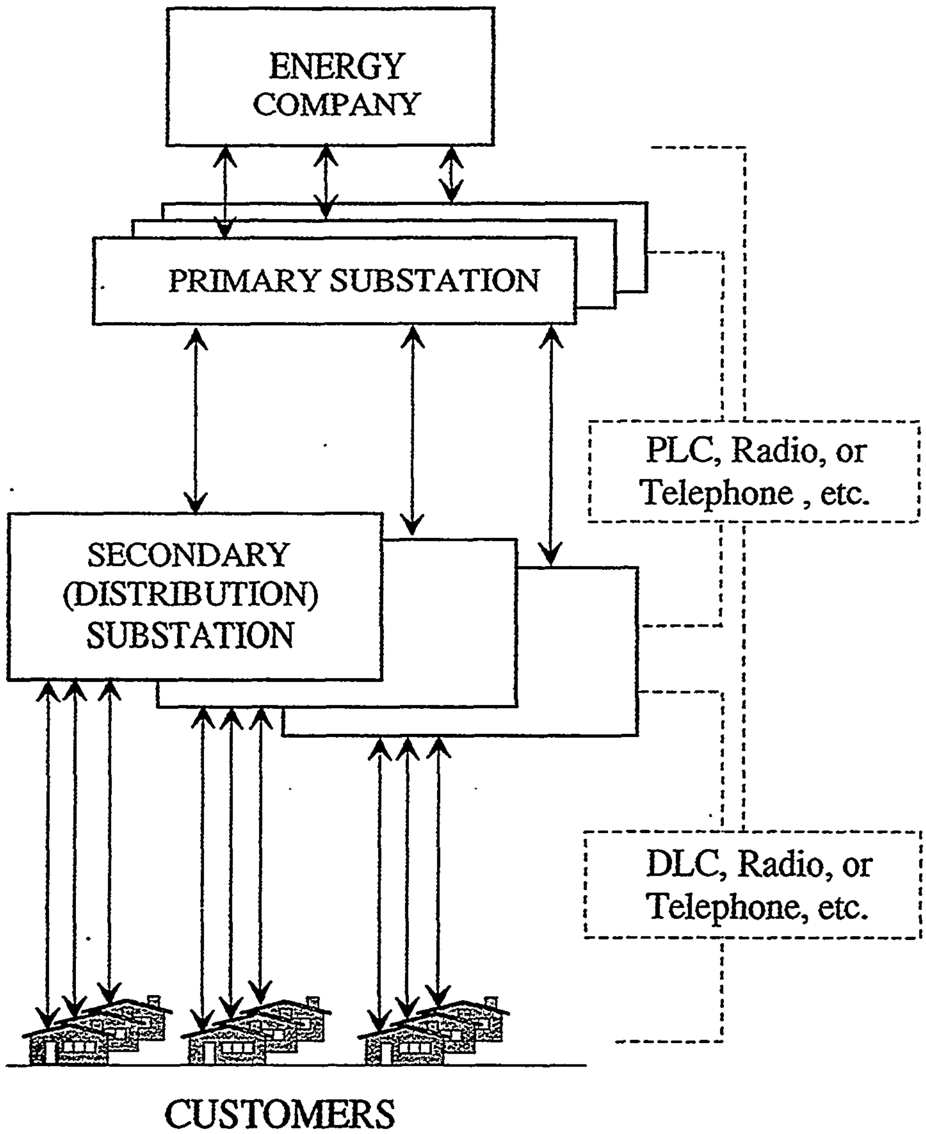


Fig. 64. Communication systems for Demand Side Management may consist of a hierarchical structure. Communication between the Primary Substation and the Secondary Substation can use one technology, while communication between the Secondary Substation and the Customer may use the same technology or other technologies.

14 COMMUNICATIONS ARCHITECTURE FOR AN ELECTRIC COMPANY, EUROPEAN UTILITY COMMUNICATIONS ARCHITECTURE, EURUCA

Pentti Uuspää, VTT Energy

14.1 SCOPE

The scope of this research is integration and interoperability of various information systems and data communications for electric utilities.

14.2 OBJECTIVES

Utility Communication Architecture refers to an overall view of the communications needs and communication systems in an electric utility. The objective is to define and specify suitable and compatible communications procedures within the Utility and also to outside parties.

14.3 UCA

Utilities Communications Architecture (UCA) was a project for developing a communications architecture that covers the whole scope of communications needs for utilities.

The UCA project was coordinated by the Electric Power Research Institute (EPRI). The work produced UCA Version 1 which was completed in 1991. Documents of UCA Version 2 have been published in 1997. UCA activities have been moved to IEEE in 1997. IEEE now organizes the UCA Forum, which was earlier the MMS Forum.

The principal business areas of a utility are served by local area networks. The separate areas and networks that are recognized in the UCA model are:

- Power Plant Network
- Control Center Network
- Transmission Network
- Distribution Automation Network
- Customer Interface Network
- Corporate Network

These local networks are connected by a Company Wide Area Network.

There are also connections to External Wide Area Networks. Thus there are communications available to external organizations, such as other utilities, vendors, regulatory agencies, power pool, Independent Power Producers, and other power plants.

The seven-layer Open Systems Interconnection (OSI) model is often used as a reference framework when communications protocols are discussed. For the UCA, OSI-model has been chosen as a basis.

Standards which cannot work within an OSI framework cannot be incorporated into the UCA.

14.4 EURUCA ORGANIZATION

EURUCA is a European joint project for developing communications architecture adapted for the European utilities.

The EURUCA (European Utility Communications Architecture) Project is managed by KEMA in the Netherlands. EURUCA draws background material from the Utility Communications Architecture (UCA) which was studied in the United States coordinated by EPRI.

There are a number of Utilities from the Netherlands participating. These include both production companies and distribution companies. Some of the Dutch distribution companies are quite large.

Contributions from other countries have come from EDF in France, Vattenfall in Sweden, and VTT Energy in Finland with interviews and expertise from some Finnish Electrical Companies.

14.5 RESULTS OF PHASE 1.

In the first phase, the project has carried out an inventory of the

- locations,
- business processes,
- data flows, and
- characteristics of the data flows of the Utilities

for the European situation. An extensive survey was made about the data flows and about their requirements for data communication.

14.6 PHASE 2: TECHNICAL DEMONSTRATOR

The second phase of the EURUCA project includes a demonstration of the utility communication systems. Existing systems are used, in cooperation with manufacturers, to demonstrate compatibility and integration of systems. A selected set of functions is chosen for the demonstration.

A technical demonstration has been organized at a seminar in Amsterdam October 13, 1997, next to the DA/DSM Europe 1997 Conference.

14.7 OBJECT MODELING TECHNIQUE (OMT)

Object Modeling Technique can be used for analyzing, designing, and implementing information systems. Object Modeling helps in analyzing systems especially when there are existing systems, and new systems that need to be integrated.

14.8 USE CASE METHOD

Use Case approach analyzes user's tasks, and identifies, which applications the user needs to access.

Use Case Method has been discussed in detail by Jacobson and coauthors.

14.9 FRAMEWORK BASED ENVIRONMENT (FBE)

Framework Based Environment (FBE) is a method that is based on Rumbaugh's Object Modelling Technique (OMT), and on Jacobson's Use Case Method.

14.10 CORBA (COMMON OBJECT BROKER ARCHITECTURE)

CORBA is a technique for interconnecting applications to work together.

CORBA looks like a common data-bus, that has been done in software, instead of hardware.

An interconnection to CORBA system will be developed for each application, including the existing "legacy" systems.

14.11 RESULTS

Two Scoping and Assessment Workshops and a review session have been organized for Modelling of information systems.

A number of Use Cases for electric utilities have been defined and examined for the purposes of a Technical Demonstrator.

The Use Cases considered, included the following:

- Customer has no power
- Contract problem of Domestic Customer
- Customer Gateway report
- Peak Shaving
- Using Customer Gateways for Load Estimation

A technical demonstration has taken place in 1997.

Note: This summary describes Finnish participation in an international research project, the EURUCA project, with participants from Finland, France, the Netherlands, Sweden, and Switzerland. EURUCA project is managed by KEMA in Arnhem, the Netherlands. VTT has participated in the project until mid 1997.

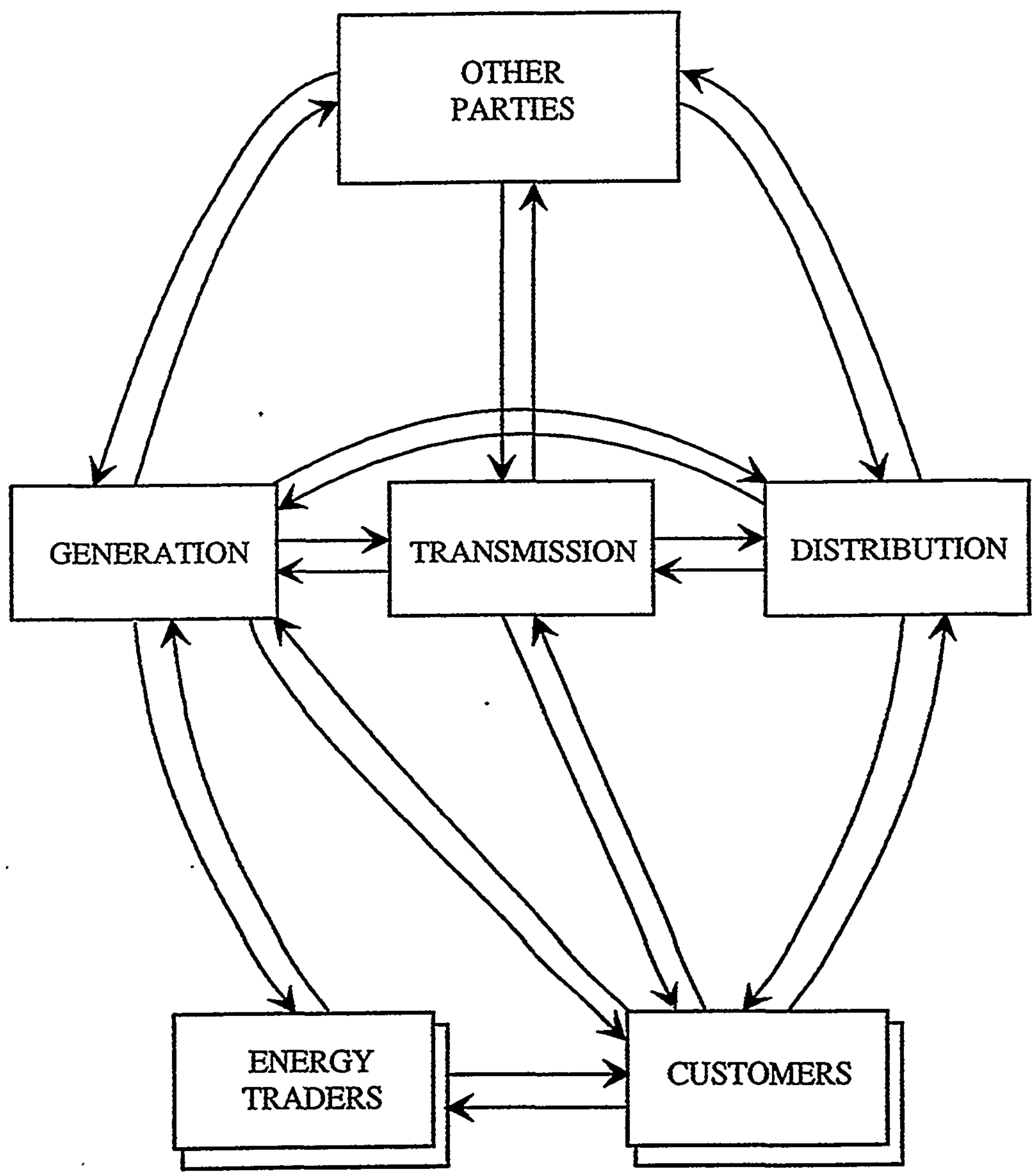


Fig. 65. European Utility Communications Architecture (EURUCA) project models the locations, business processes, and data flows for an Electric Utility. The model has a hierarchical structure in the sense that the items "Production", "Transmission", and "Distribution" have been further divided into their components as well.

15 OPTIMISATION OF LOAD CONTROL

Pekka Koponen, VTT Energy

15.1 INTRODUCTION

Electricity cannot be stored in large quantities. That is why the electricity supply and consumption are always almost equal in large power supply systems. If this balance were disturbed beyond stability, the system or a part of it would collapse until a new stable equilibrium is reached. The balance between supply and consumption is mainly maintained by controlling the power production, but also the electricity consumption or, in other words, the load is controlled. Controlling the load of the power supply system is important, if easily controllable power production capacity is limited. Temporary shortage of capacity causes high peaks in the energy price in the electricity market. Load control either reduces the electricity consumption during peak consumption and peak price or moves electricity consumption to some other time.

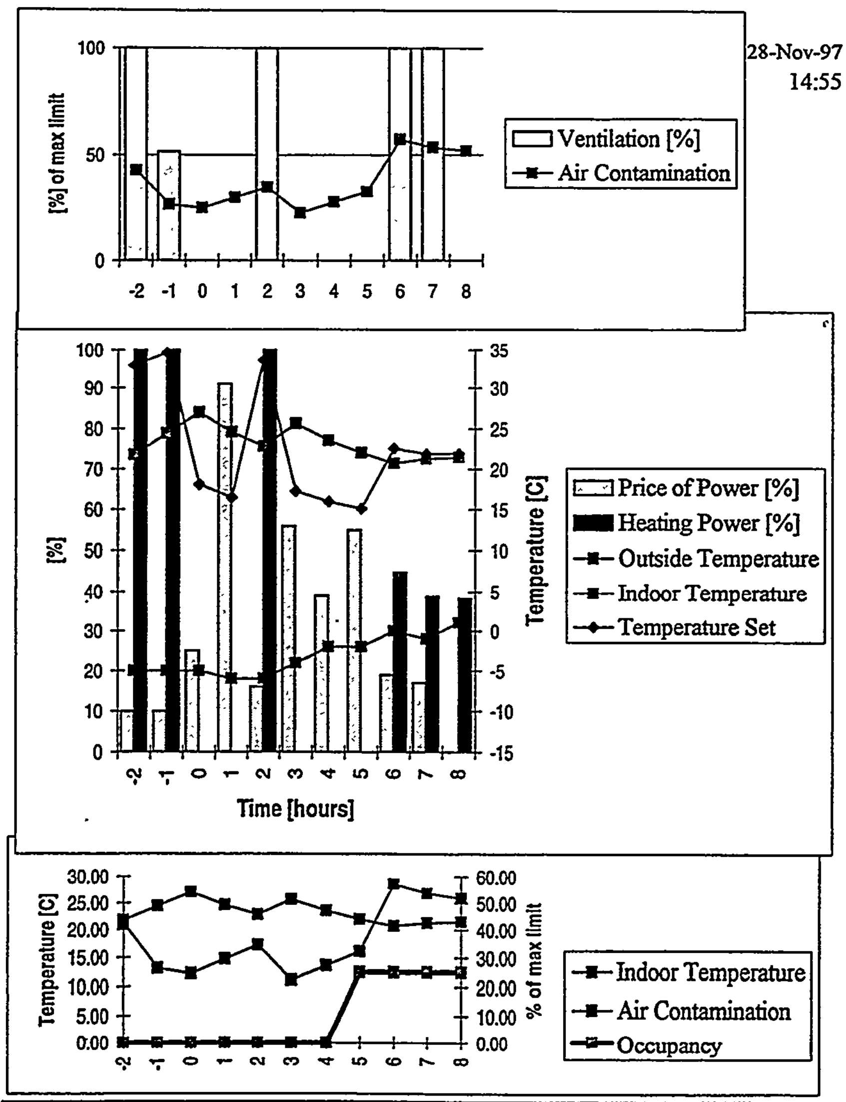
The project Optimisation of Load Control is part of the EDISON research program for distribution automation. The following areas were studied:
- optimisation of space heating and ventilation, when electricity price is time-variable
- load control model in power purchase optimisation
- optimisation of direct load control sequences
- interaction between load control optimisation and power purchase optimisation
- literature on load control
- optimisation methods
- field tests and response models of direct load control
- the effects of the electricity market deregulation on load control.

An overview of the main results is given in this paper. In /17/ the results are explained in more detail.

15.2 OPTIMISATION OF SPACE HEATING WITH TIME VARIABLE PRICES

Optimisation of energy use for space heating was demonstrated and studied by simulations. A simple differential equation model of heat flow and storage of a building was constructed. The variables of the model were indoor temperature, wall temperature and inside air contamination (CO_2 content). In addition to two uncontrollable input variables, occupancy and outside temperature, the model has two controllable input variables: space heating power and ventilation. The time variations of the control inputs were optimised. Loss of comfort in the building and energy costs were minimised using a constrained non-linear optimisation method. This task is reported in reference /16, p 749 - 752/. Figure 66 shows an example solution in a possible user-interface.

It was observed that the potential to reduce energy costs by optimisation increases considerably, if ventilation, direct heating and heat storage can be controlled separately. The customer can take advantage of dynamic tariffs much better. When the number of time steps was increased to 16, the method became too sensitive to the starting guess. However, about 48 time steps would be ideal for the problem. The model could be made more realistic by adding the heat flow between the ground and the building and a heat storage, which represents the internal walls and other internal masses of the building.



	Power Costs	Comfort	End State	Total Criterion
Weights	100	80	240	
Costs	3627	836	190	4653

Fig. 66. An example of heating and ventilation load optimisation.

15.3 LOAD CONTROL MODEL IN POWER PURCHASE OPTIMISATION

A simple space heating load model with linear dynamics was developed and added to a power purchase optimisation program that has been developed in VTT Energy Systems. The load control model represents a space heating customer with dynamic price control. The model includes time variable constraints on state and control variables. The performance of the optimisation system with the new model was tested only with simulations. The power purchase model was based on data from a distribution utility that has its own thermal power plant and contracts to use the production of some other power plants. In the test runs an imaginary power sales price was successfully used to tune the characteristics of the load control solution.

This approach has some limitations:
- The ventilation rate cannot be varied in the model, because it would make the model non-linear. It would be possible to construct a linear approximation near the normal operating point, but this was not tried.
- The load control model could only be used for day or week optimisations and not in the optimisation of the power dispatch of a year. The optimisation program includes two methods. One is normal Linear Programming (LP) and the other is a special method for large dynamic LP problems and is called DLP. DLP solves the power purchase plan for each hour of the year in about the same time as normal LP solves the same problem for a week or two. The load control model introduced often caused convergence problems to the DLP solution. With the normal LP the model works fine.

The model helps the power purchase optimisation to anticipate the load control response and its effect on the marginal power prices, see Figure 67. Thus it will improve the interaction of the power purchase optimisation and the optimisation of load control.

The model enhances the use of the power purchase optimisation as an interface between the electricity spot market and load control. The spot market cannot directly deal with dynamic interactions such as the after-peak of load control. The model takes care of the energy storage effects. In the power purchase optimisation both purchase and sales can be presented as standard spot market products. Thus it is also possible to sell load control capacity to the spot market.

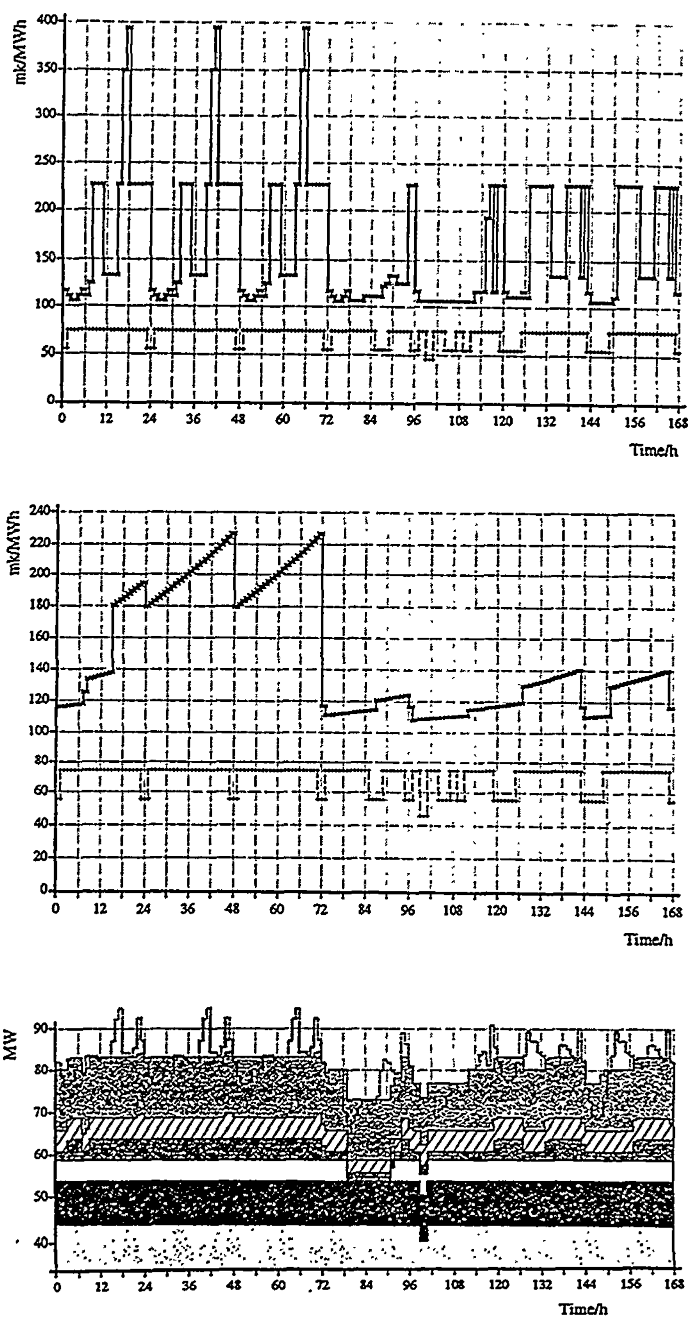
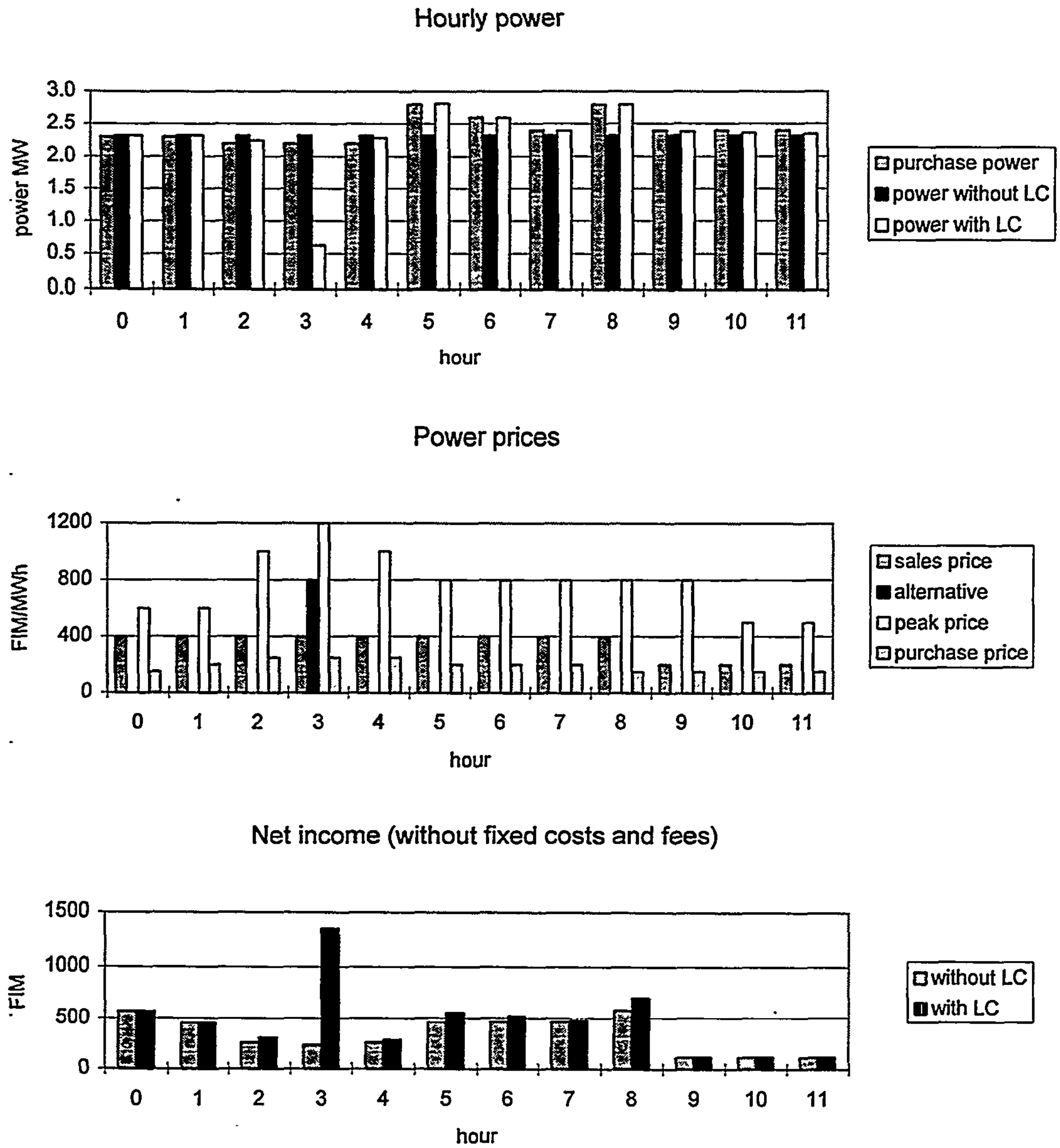


Fig. 67. A simulation example of power purchase optimisation with a load control model. In this case the amount of controllable load is exaggerated. Explanation:

Top: Marginal prices of electricity and heat without load control
Middle: Marginal prices of electricity and heat with load control
Bottom: Electricity production and trade plan with load control,

the dotted line is the total demand without load control.



	Without LC	With LC	Difference
Total	4098	5572	1473 FIM

Fig. 68. An example of load control sequence optimisation; the problem was solved using evolution strategies.

Top	*Purchase power and power with and without load control*
Middle	*Prices*
Bottom	*Net income without and with load control.*

15.4 OPTIMISATION OF DIRECT LOAD CONTROL SEQUENCES

Most existing load control systems for space heating are implemented in a way that requires the use of control sequences. Thus the optimisation of these sequences is needed. This type of direct load control system is very simple to install, but can only partially utilise the load control potential of space heating. By using a little more advanced load control it is possible to save significantly more in the power purchase costs without losing more comfort. Also total shutdowns and after-peaks could be eliminated and with them most of the need to optimise the sequences. However, the change of the customers' terminal units would be too expensive.

Many utilities in Finland have systems for direct load control of electric space heating. These systems send, via the distribution line, commands to shut down the heating for a specified time. Typical for this type of control is that immediately after the shut down period there is an after peak in the load, because the inside air temperature is heated as soon as possible back to its set-point value. The re-heating of the structures of the building is much slower and has a time constant of one to several days.

To limit the load control induced loss of comfort experienced by the customers, the load control agreements contain limitations on the length of the control periods and minimum intervals between them. This type of modelling of customer comfort is very rough because the temperature drop in the house depends on other things such as: outside temperature, ventilation, activities in the house and the possible use of other forms of heating.

In these direct load control systems the loads are divided into load control groups for the following reasons. 1) Different buildings have different responses and different allowed control times and recovery times; thus within each group the buildings should be similar. 2) After-peak is smaller, when load controls do not end at the same time; otherwise the network might be overloaded. 3) By controlling the loads in a sequence it is possible to shift the load over to a much longer time without breaking the agreed rules.

Enermet has built a prototype program for the optimisation of direct load control sequences. The executable of this program was received. The program consists of several separate heuristic methods and a method based on dynamic programming. The heuristic methods are faster, but also the dynamic programming method solves the problems fast enough, because it optimises each load control group only separately. Thus the dynamic optimisation method does not reach the optimal solution of a combination of several groups. In order to know how far the solutions are from the global optimum a suitable reference method is needed. The interfaces of the prototype still need much development.

Also our own optimisation experiments with this problem have been carried out. The purpose has been to get some reference solutions for the evaluation of the Enermet prototype and possibly a method with a more straightforward interface to the load control response models. Two evolutionary optimisation methods were tested, because they are suitable for searching for the global optimum. With these methods it is also easy and flexible to add heuristics, which limit the search space. It is necessary to limit the search space somehow to keep the solution time acceptable. The methods are evolution strategies and genetic algorithms.

It was learned that evolution strategies is suitable for finding reference solutions. However, so far it has not been fast enough for normal online use. Tests using genetic algorithms have also been started. In addition mixed integer programming (MIP) as in reference /37/ or non-linear constrained optimisation could be used to solve direct load control scheduling. The scope of this project is too wide and resources too limited for thorough study and evaluation of all possible approaches.

In Figure 68 there is an example of a load control sequence optimisation. Loads with and without load control are compared. The load is close to and sometimes even above the purchased power, when there is no load control. It is assumed that when exceeding peak power it can be bought from the electricity spot market. In addition there is an opportunity to sell electricity to the market at a good price in this case. The prices in the test case are arbitrary. The solution uses the different possibilities to maximise the net income.

15.5 INTERACTION OF LOAD CONTROL OPTIMISATION AND POWER PURCHASE OPTIMISATION

Load control consists of two optimisation problems with different objectives. One minimises the purchase costs of the needed power and the other maximises the comfort or the profit of the customer, see Figure 69. Alternative interaction principles are needed depending on the characteristics of the loads and control systems of the customers. Description of this interaction problem, different alternative configurations, previous work and some simulations were reported in /16/. The simulations of price control comprised the following basic cases: 1) space heating and ventilation, 2) other continuous processes and 3) a series of interconnected batch processes. Especially dynamic price control requires that the consumers of electricity have adequate automation systems for control, scheduling and operation planning of their processes. The production, operation and maintenance plans created by these automation systems also give the planned electricity consumption of the process or building. These forecasts of consumption are useful for power purchase optimisation. Also the interaction with systems for direct load control was considered.

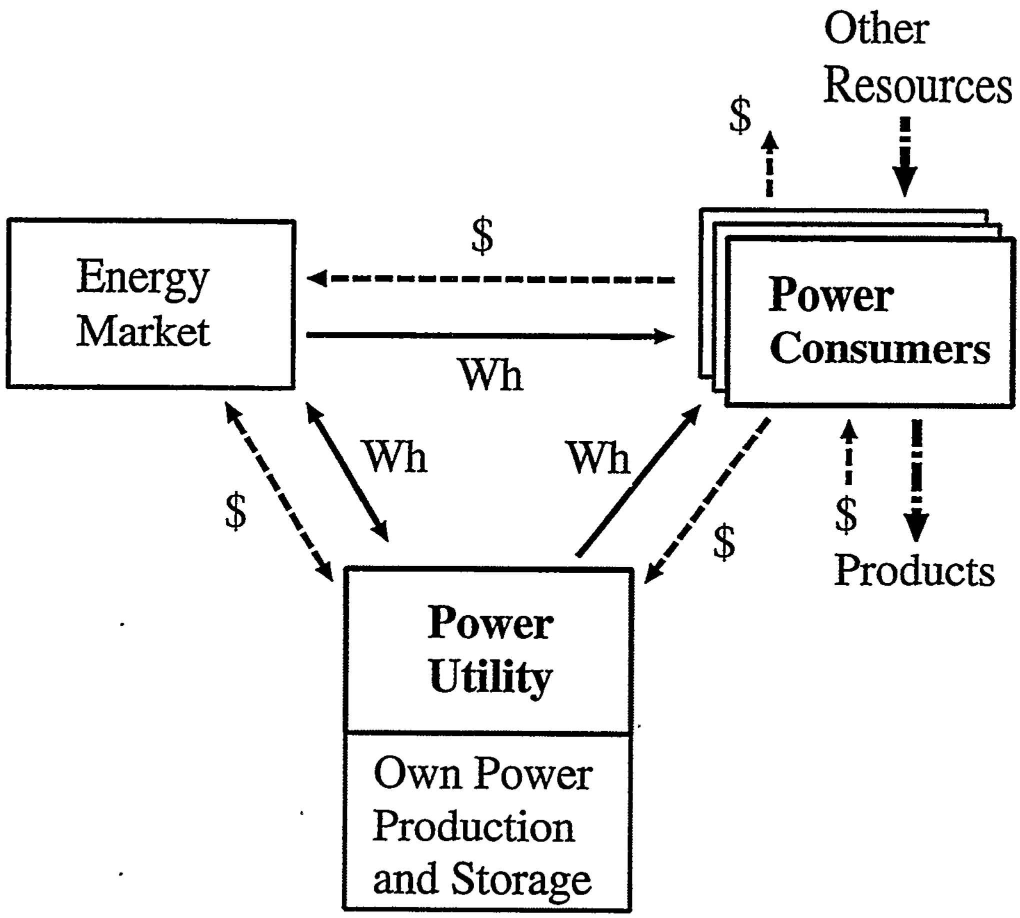


Fig. 69. The interaction of the utility and its customer in load control.

15.6 FIELD TESTS OF DIRECT LOAD CONTROL RESPONSE MODELS

Accurate response models of load control are very important for the success of load control optimisation. In order to verify and develop these models, field tests with direct load control systems were carried out. During the tests, in two utilities (Koillis-Pohjan Sähkö and Oulun Seudun Sähkö) the power measurements were collected from substations and in one (Keski-Suomen Valo) only the total utility load was recorded. In /18/ the field tests and our new load control response model are documented and compared to a previous model of /40/. Also a literature review on response models for direct load control is included.

The field tests started on 16 December 1996 and ended 24 January 1997. An example of measurement data is shown in Figure 70. (After 15:00 a data communication failure and half an hour later a system failure are shown. The ripple in the data is caused by the rather large measurement pulse size.) The weather conditions were not good for load control tests, because the cold periods were too short. It was impossible to identify the parameters of our traditional load control response models with required accuracy directly from this data. However, the plan was also to test a new physically based model structure and it worked well. The new load control model has more parameters, but this is compensated for by its ability to use advance information on the properties of the houses. The effect of outside temperature is also built into the model structure.

In Figure 71 an example of the response of the model is shown The measured load represents two ski resort areas and the measurement of a reference day has been subtracted. Four different load control groups were controlled, one at a time. The outside temperature was around - 19 °C. The parameters of the prediction model are identified from load control tests of normal houses in a nearby utility. Advance information on the group sizes and heat storage capacity was used to scale the respective parameters of the model.

Some new load control terminals may control the set-point temperature or limit the after-peak by other means. It is easy and straight-forward to include such features in the new load response model. With the earlier model that would have been very difficult.

15.7 EFFECTS OF ELECTRICITY MARKET DEREGULATION ON LOAD CONTROL

The new competitive electricity market improves the visibility of power production cost variations. Thus it improves the possibilities to substitute load control for controllable power production on a national level. However, the required changes in the company structures make the access to load control methods and the co-ordination of different load control objectives more difficult than before.

The power transmission and distribution network operators and the electricity trade business operations are separated. The network company must treat all electricity sales companies equally. Load control is mainly used to reduce peaks in power purchase costs. However, load control systems are often integrated in network automation systems and owned by the network company. This means that the network company should sell load control services to electricity sales companies or the relevant customers. The sales company and the customer need to agree on the terms that are applied in load control. The sales company must somehow tell the network company when the loads are controlled. Instead of two parties there are now three or more parties that need to make agreements before load control can be applied.

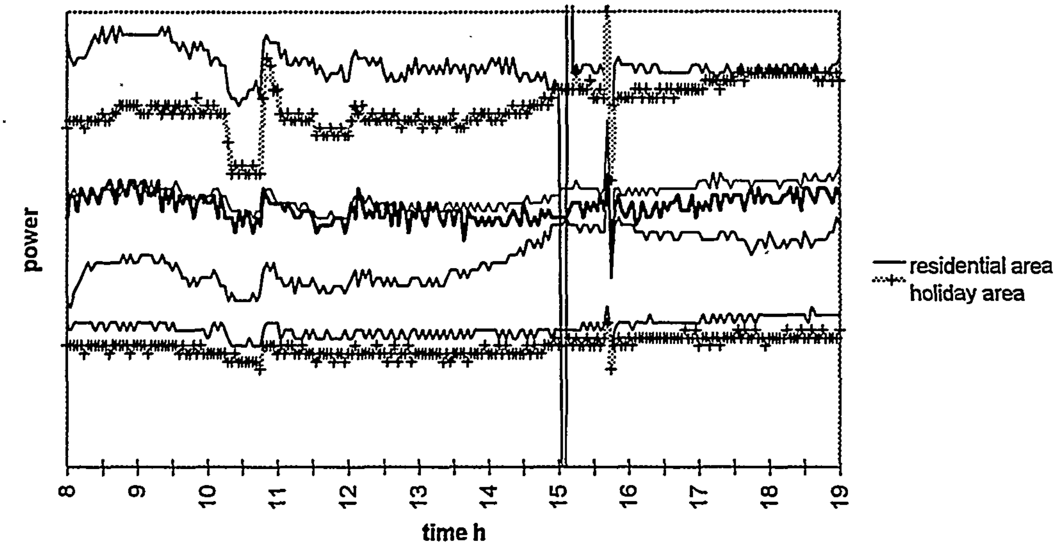


Fig. 70. An example of substation load measurements, 16 December 1996. Four load groups were controlled one at a time, controls start at 10:15, 11:30, 13:15 and 14:20. The respective groups are 1) direct, 2) partially storing, 3) storing and 4) partially storing heating.

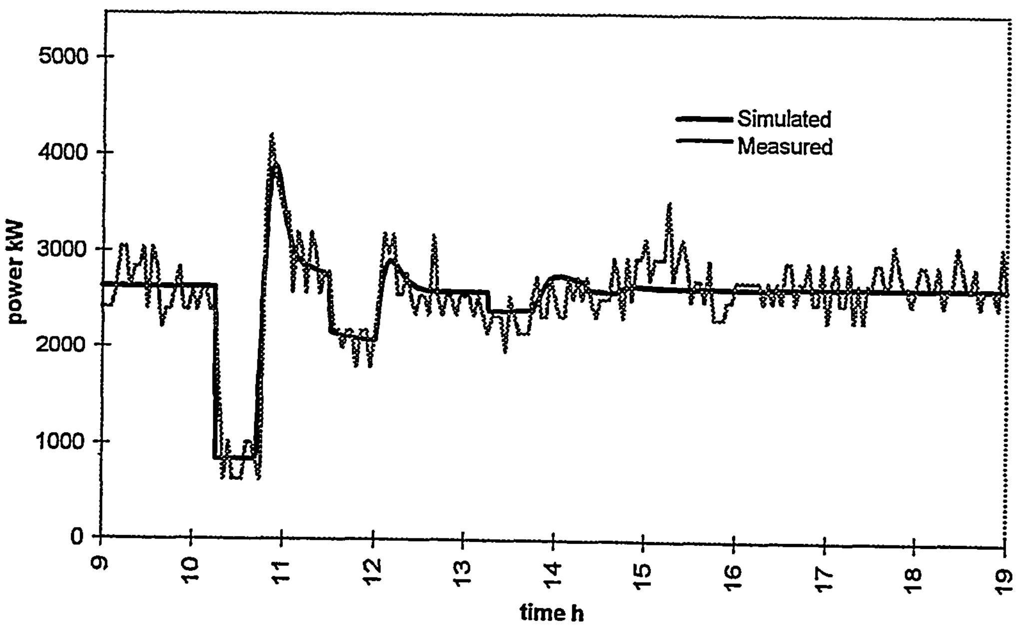


Fig. 71. An example of the prediction performance of the model. 16 December 1996. The measurement is the power of the holiday areas in the previous figure with a reference day subtracted. The simulation parameters are based on tests on another day with residential customers in a nearby utility and prior information on the group size and heat storage capacity.

Of course, the electricity sales company can arrange the load control without using the services of the network company. The sales company can have a load control system of its own or buy the services for example from a metering company. The customer may easily change sales companies. This may make the sales companies reluctant to invest in load control terminals and systems.

Network capacity constraints and losses must be taken into account when controlling the loads. If electricity sales companies are allowed to control loads without taking the network limitations into account, there is a risk that load control worsens the reliability and quality of power supply, causes high distribution losses and reduces the age of network components in some residential areas. There, dense application of time-of-use-tariffs and load control increases the network peak load in addition to moving it to periods of low market prices. Load control can also be used to postpone investments in distribution networks. The often conflicting load control interests of sales companies and network companies need to be balanced somehow.

Typically direct load control causes a high load peak immediately after the end of the load shed (or load-off) period. This is sometimes problematic for the network loading and for the scheduling of load control actions. This after peak could easily be avoided by improving the interaction of the temperature control and the load control terminal. The changes to already installed terminals are expensive to make, however.

With the deregulation, public market places for electricity have been introduced. Especially the daily spot markets have consequences on load control. In practice the capacity components and limits in tariffs are becoming less restricting than before. The tariffs are more often based on hourly energy; thus the energy price for each hour is agreed in the tariff. The variations of power production and purchase costs become more visible to the customers. This increases the motivation of the customers to control their loads according to the variations in energy prices. Thus the customers will control their loads themselves more than before. The price elasticity of the demand increases. This reduces the need and potential for direct load control.

During winter 1996/1997 the spot prices in Finland were always so low that they do not justify investments in load control systems. Some reasons for the low spot market prices can be found. The spot market tends to reflect the instantaneous variable costs of marginal power production. The winter was mild without significant forced power plant shutdowns. In this situation many market actors seemed to sell their excess spot energy close or sometimes even under the prices of their long term purchase contracts. On the other hand, the temporary water shortage in Norway and Sweden raised the price level.

In Finland the reserves for power production capacity and control power are limited. If a shortage of these occurs, sudden peaks in the market prices will result. In such situations load control is a useful and valuable resource.

The sanctions for exceeding the capacity limit were very high in the wholesale tariffs before the market deregulation. The investments in direct load control systems were clearly profitable in those circumstances for utilities with scarce control power resources.

Those who have operating load control systems can now sell the load control energy to the market, when there are large rapid price changes. However, bidding mechanisms that can take into account the special characteristics of load shifting may need to be developed. One way to handle this is to use power purchase optimisation with a load control model

In the new market situation there are several sales companies selling to the same network. The effects of load control need to be known in order to determine the commercial power balance fairly. Can this be done, if the hourly customer loads are not measured? Measurements at the substation and our new load control response models will tell the load control response accurately enough, if the model parameters are appropriate for the load group. However, only the total response of the group is known. Individual malfunctioning or tampered terminals or loads in the wrong load group cannot be singled out from the substation measurements.

The effect of electricity market competition on supply on demand control in the UK is discussed in /5/. Since privatisation of the UK electricity industry, classical Demand Side Management techniques have not been valid in England and Wales, where the only commercial link between generation and distribution is through the electricity pool. Now demand control is used mainly to avoid the need for distribution system reinforcement. Difficult access to a demand control facility means a less economic supply, over-engineered in the longer term and potentially affecting supply quality and even security in the short term.

15.8 SUGGESTIONS FOR FURTHER RESEARCH

The new direct load control response models need some further field tests for verification. Also the effects of sauna, cooking and other activities on the load control response need to be identified and modelled. The direct load control scheduling methods need some further development before test use or integration with power purchase optimisation is appropriate. Simulations of the combination of the power purchase optimisation and scheduling of load control sequences are needed to verify the suggested interaction principle. The potential benefits of load control in the new electricity market situation can be more accurately assessed using the same simulation and optimisation tools.

The developments in various areas change the possibilities and potential for load control. Data processing, data communication, building automation and home automation make new more advanced load control methods possible. The heat losses of buildings have become smaller and heat pumps and heat recovery can reduce the electricity consumption of space heating greatly. Continuous development of the competitive energy market is also anticipated. Research to adjust the load control methods and systems is needed.

Some methods for bidding load control to the market are needed. These should make it possible to offer control of space heating to the electricity spot market just like any other controllable power production capacity.

15.9 CONCLUSIONS

Optimisation methods are necessary in order to get the potential benefits of the load control systems. In this respect it does not matter, if the load control is direct or indirect. The basic space heating problem with a constant ventilation rate and continuous control signals can be solved fast enough using linear programming. Varying the ventilation rate increases the load control potential of space heating loads but makes the model non-linear and thus more difficult to solve. Existing direct load control systems have other difficulties that result from agreed constraints on control signals and overly simple customer side control logic. The optimisation problems can be solved with available methods but the length of the solution time makes it necessary to simplify the problem formulation in online tasks.

New load control response models were developed and the field test results are promising but some more field test data is needed. The new model structure is linear with control constraints and it combines a-priori information on load groups with measured response data for the prediction of load control responses.

The deregulation of the electricity market has put the load control in a new situation. It has became difficult to predict the profitability of load control investments and more companies need to be involved before load control can be put into practice. The use of indirect load control will increase because the power production costs are more apparent to the customers. Direct load control is necessary only, when there is a sudden large shortage of easily controllable production capacity. The load shifts by direct load control can be sold to those who need it. The network limitations need to be taken into account in the planning and scheduling of load control. How it can be done without violating the competitive electricity market framework, is a challenge. For the load control optimisation methods this means that often the distribution costs need to be included either in the optimisation criterion or constraints.

16 ELECTRICITY SPOT PRICE FORECASTING IN FREE POWER MARKET

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16.1 INTRODUCTION

Deregulation has brought many changes to the electricity market. Freedom of choice has been granted to both the consumers and the utilities. Consumers may choose the seller of their energy. Utilities have a wider array of sources to acquire their electricity from. Also the types of sales contracts used are changing to fill the needs of this new situation.

The consumers' right to choose has introduced a new risk, uncertainty of volume, which wasn't true during the times of monopoly. As sold volume is unsure and the energy is not sold on same terms as it is bought, a price risk has to be dealt with also. The electric utility has to realize this, select a risk level that suits its business strategy and optimize its actions according to the selected risk level.

The number of participants will grow as the electricity market integrates into a common market for Scandinavia and even Europe. Big customers are also taking a more active role in the market, further increasing the number of participants. This makes old bilateral arrangements outdated. New tools are needed to control the new business environment.

The goal of this project has been to develop a theoretical model to predict the price in the Finnish electricity exchange, El-Ex Oy. An extensive literature review was conducted in order to 1) examine the solutions in deregulation of electricity markets in other countries, esp. in Norway and UK, 2) find similarities and differences in electricity exchange and exchanges generally and 3) find major sources of problems and inefficiency in the market

16.2 Deregulated electricity market and electricity exchange

To get the best results from deregulation, an efficient marketplace mechanism is needed. Two things determine the advantages one market arrangement has over another: the price level itself and administrative costs. The price has to be a true market price, meaning that the buyer is paying more than other bidders and the seller's price is the lowest one existing. The trading itself should also be economical, not needing too much administrative resources. An exchange has proven to be as a good a solution as the marketplace.

Market mechanisms affect the spot pricing of energy. In order to predict price it is important to understand these machanisms. As electricity exchanges are a very recent phenomenon, research on them is still quite modest. The practices and logic of traditional exchanges can be compared to these new marketplaces.

16.2.1 Electricity market

With deregulation the rules of electric energy trade were totally rewritten. Of course the physical system of generation, transmission and distribution was not changed, but the new rules will affect companies' investment behaviour. Change has launched many protests as changes often do. The Finnish electricity system didn't have serious weaknesses, so why did it have to be changed? The competition, not only inside Finland but in Scandinavia and Europe also, dictates that the use of capacity and resources be more efficient.

The arrangement of deregulation in Finland is similar to the Norwegian system. Participants may freely make transactions with each other. Thus, there is competition in producing and selling electricity, which should result in more efficient usage of resources. In the Scandinavian solution for deregulation there is no single company that all producers sell to and all buyers buy from, as there is for example in the UK. The Scandinavian system allows every interested party to actively act in the electricity market, which increases the number of participants and should promote competition.

The place for all energy trade in Finland, as in Norway also, is the high voltage network. All participants may use the high voltage network on an equal basis. No limitations were placed on the types of contracts that may be used; the participants choose themselves. Buyers and sellers only have to inform the amount of a trade, not prices, for calculating energy balance.

Grids are however still monopolies. Public demand for competition in the production and selling of power has forced utilities to grant third-party access to the network.Third-party access means that the owner of a grid has to allow other sellers to use its grid to supply consumers connected to it. The owner charges a compensation for using its network, but this compensation has to be the same for everyone, including the owner itself. Thus the price to a customer includes two components, one for energy and other for the transmission and/or distribution.

In the utilities, network operation and energy producing and selling activities have to be separated. At the moment (01/97) the separation is done in accounting. Separate income statements and balance sheets are reported for grid operation and energy sales activities. The Electricity Market Center (EMC), the monitoring authority in Finland, is currently investigating the possible benefits of dividing utilities into separate distribution and selling companies.

One major weakness in deregulation is the difficulty to improve efficiency in the business areas that are still monopolies. The only way to force efficiency improvement in monopolies is for the EMC to take an active role. It may for example force some companies to lower their distribution prices to compensate for worse efficiency.

In order to get full advantage from deregulation, a marketplace is needed, to determine a market price to inform all participants of the current situation in the market. This signal then guides participants to take actions in the most economically advantageous way. Before deregulation the marketplace was unorganized, and even though producers did co-operate in generation planning, most trade was bilateral and the optimum was not always reached.

16.2.2 Electricity exchange

The benefits of a system bringing together the participants in the market are determined by the price of electricity itself and the administrative costs related to trade. The main reason the electricity exchange exists is to offer a price-efficient solution to bring together buyers and sellers.

A good marketplace should be

- neutral, so that all participants are treated equally
- price-efficient, to enhace liquidity and make sure that no other marketplaces are needed
- regulated, so that the marketplace has clear rules and an authority to make sure rules are followed
- standardized, to ease trade and make new participant entrance easier
- equal in information availability
- anonymous, as merely the presence of a big participant may influence prices
- accepted, as without acceptance no marketplace can succeed.

In Finland an electricity exchange, El-Ex Oy, was set up by SOM Oy, which runs a derivative securities exchange in Finland. At the moment, the volume of trading isn't very high, but the price on short-term bilateral trades is nowadays always compared to exchange prices. El-Ex is mainly used to even differences between production/purchasing and selling/consumption of energy. After deregulation two energy balances need to be calculated, one for actual energy production and consumption (technical balance) and another to state the rights and liabilities of each participant in a commercial sense (commercial balance). A company has to have produced and/or bought the amount it or its customers have consumed. Any differences, positive or negative, are then settled.

The instruments currently used on the exchange are forward contracts. In a forward contract both sides have to keep the agreed terms, that is,one will deliver energy and the other will pay the price agreed at the time when the forward was sold/bought. All agreements are for the delivery of 1 MWh of electricity at the specified hour. It is possible to trade up to 2 years into the future, but then the products are first seasons (26 weeks) that break down into four week blocks, weeks and finally, about 2 weeks before delivery hour, into single hours.

In the future, options are likely to be introduced. In an option agreement, one buys the right but not the obligation to buy or sell at a specified price at some date in the future. The seller must fulfill the agreed terms if the other party chooses to exercise the right purchased with the agreement. This adds new possibilities to price risk management. By combining different options a desired risk level can be obtained.

All instruments currently used in El-Ex basically lead to actual delivery of electricity. However only net amounts are informed to the energy balance calculator, so it is possible to close a position before delivery. There are no derivatives that do not lead to physical delivery traded on El-Ex at the moment.The difference between the contract price and the reference price (usually the spot price) is credited/debited to the participants involved. The lack of financial instruments has lowered the interest of speculators in the market. At the same time utilities have felt that instruments that lead to delivery better serve their needs

El-Ex at present is not very similar to other exchanges. The product, energy delivery during one specified hour, cannot be stored and has no value after the delivery hour. The goal of the exchange is of course the same in all exchanges, as are the mechanisms of trading. The role of the biggest producer, IVO, is also problematic. IVO has access to much more information than other market participants. This, and the fact that IVO is the market maker in El-Ex may cause distrust among other users. On the other hand market volume is so low that there has to be a market maker. As all contracts lead to delivery, IVO is the only possible candidate for the position.

16.2.3 Effects of deregulation on the electricity industry

Deregulation and the introduction of the electricity exchange has naturally changed the electricity business. Producers have been forced to rewrite the bulk trade contracts used to sell electricity to a utility. The need has arisen from the removal of resale restrictions between utilities. As the Finnish power system is limited by power rather than energy, the price of electricity sold by producers with several different generating plants rises with power used during any given hour. The seller has to be able to predict the amount of energy it has to acquire at a given hour.

Before deregulation a utility could either produce electricity itself or buy it from a (large) producer with a long-term contract. The structure of payments in the contract was equal to the cost structure of the producer. This way the producer minimized its risks, but at the same time this kind of contract made big investments such as nuclear plants possible. Short-term bilateral trade was done, but it was just for temporary needs.

With the introduction of the electricity exchange, an efficient place for spot trade was established. Ideally it will be a third source of electricity. This gives new opportunities for utilities to optimize their energy purchase.

In recent years, but not necessarily connected to deregulation, foreign companies started to show a growing interest in Finnish utilities. Also, the biggest Finnish producer, IVO, started more intense internationalization.

Risks are now divided more evenly among producers, utilities and consumers. This creates not only the need for new instruments to manage these risks, but also new tools to plan the optimal usage of those instruments and combine new instruments with existing (price- and volume) risk management systems. These instruments will be offered by El-Ex or some other organization in the near future.

In Nordpool, the joint electricity exchange of Norway and Sweden, most of the participants see hedging, the use of derivative securities to lessen the risk involved in price changes, as one of the key activities in the exchange. The situation has not yet reached the same phase in Finland. Finnish participants use the exchange almost solely for spot energy trade. The systems for optimizing energy production and buying are still the same, regardless of whether energy is bought on the exchange or through bilateral trade.

The need to calculate two energy balances and the increased number of transactions involved call for developed information processing and communication technologies. The actual consumption has to be metered, all consumption of individual customers of one seller has to be combined to get seller's actual total consumption. This consumpition has to be compared to the net energy position that the seller has after its own production, purchases and energy sold on fixed contracts.. The rules and procedures for this have to be developed without delay.

The competition has raised the question of accessibility to information. Much information has value, as it can help a customer retain or make abnormal profits in the exchange possible. In larger perspective a big problem is the ensuring of equal information to all participants in the exchange.

16.3 MODEL FOR PRICE PREDICTION

An efficient model to predict both short and long-term spot-price in the electricity exchange would be a very useful tool for both optimizing the purchasing of electricity and on the other hand for managing price risk. The short-term model would probably be used for setting bids to the exchange. This would be done by the personnel that even now is responsible for spot-trade. The long-term model would have more strategic usage: It could be used to determinate the expected times of high volatility in prices so that active risk limiting could be done in those times. It could also be used in comparing shorter-term contracts with the alternative to buy from the spot-market.

16.3.1 Outline for price prediction model

Optimal usage of capacity and resourses needs planning, which is based on predictions. The methods and thus prediction models used are numerous. Producers and utilities have to have some kind of prediction of their customers' consumption and based on these predictions, they try to minimize the cost for purchasing/producing that energy.

Models used in load prediction can be divided roughly into two groups: models using only past load data and models using additional information also. However, if the model is to be useful in daily activities, its maintainence should not be too difficult. This has to be kept in mind when planning the model.

Prices in El-Ex and total production in Finland correlate. The exact nature of this correlation is still unknown, but the reason behind this correlation is clear: the price in El-Ex correlates with the cost of production and generating plants are used in the marginal price order, cheapest first. This encouraged the division of the model into two parts: One to explain the correlation between spot-price and production and the other to explain production.

This also makes it possible the take into account the different needs and uses of short- and long-term models. The function, that explains correlation between price and total production, is the same in both models. The short-term model is used to make as good pricing decisions as possible This needs far more accurate production predictions, but these predictions are already made with good accuracy for production planning purposes. The tools for day-to-day spot-trade can be built as an addition to existing load prediction models. The long-term model is used for risk management and comparisons between spot-market and other possibilities to purchase energy. The results are often recieved with a certain confidence level or expected variance.

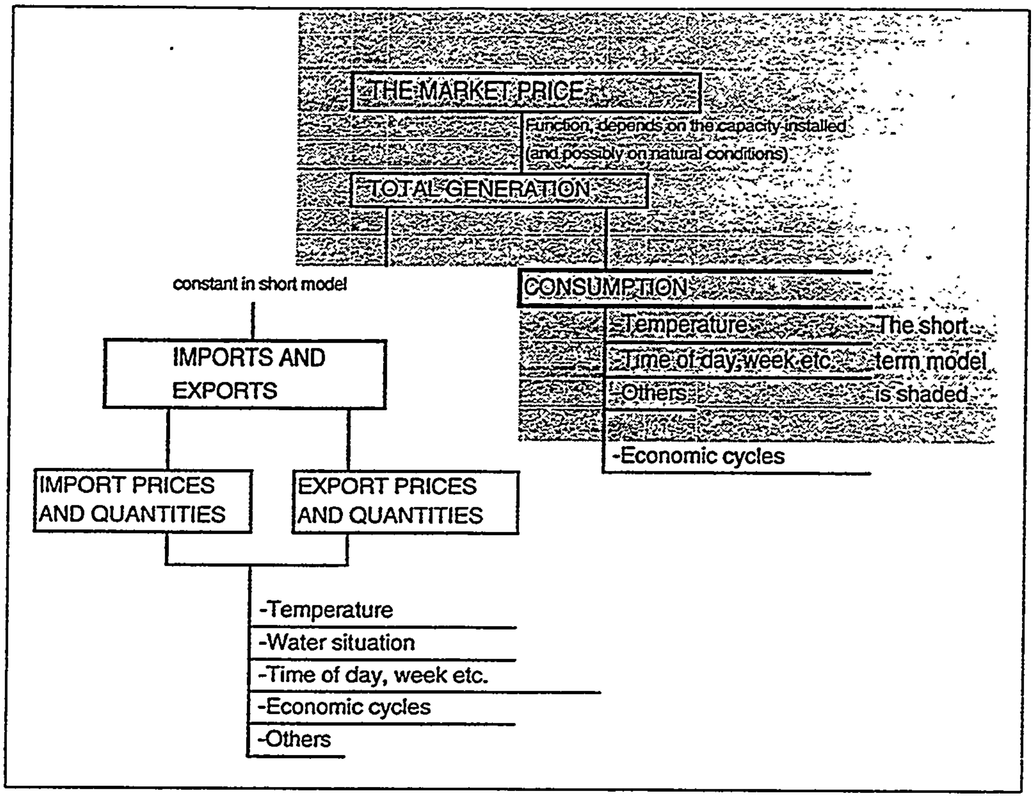

Fig. 72. Construction and parameters of the electricity spot price prediction model.

16.3.2 Proposed model

In the following a model for both short-term (< 1 week) and long-term (months to a few years) prediction will be outlined. Both consist of a part predicting total production at a given time and a function, that is utilized in both, to describe the correlation between total production and spot-price. Prediction of production in the short-term model is not discussed, as practically every major producer has a model for it.

For a long-term model the total production is predicted using regression analysis. Figure 72 outlines this regression model. The user of the model can either use mean values and variances or his own judgement. Regression analysis was selected because of the use of the model: risk management. It is vital for the user to be able to separate a single factor and examine the impact it has on production.

The relationship between production level and spot-price can be modeled to a function. This function can be estimated either from installed capacity or historical data.

16.3.3 Available data

The information used in the model has to be accessible to users and maintenance of the data bases shouldn't require very large administrative resources. If the system is similar to existing systems, the resistance to accept it is lower. The price data is available from El-Ex. At the moment it is unprocessed, so the actual figures used in the model have to be calculated from all the trades made. This will, however, be changed during 1997. There are also various sources of data on temperature and economic cycles.

At the moment total production or consumption of Finland is not measured daily. SENER, the Finnish Association of Electric Utilities, collects this data on a weekly basis and it comes with a delay of c. month. In the short-term model this is not a problem, as current price and predicted change in total production can be used. The long-term model does not suffer from the delay, but daily information would be useful. When the balance calculation system has been established, this information might be available.

Import and export are difficult to deal with. In the short-term model they can be considered constant, but in the long-term model their effect has to be taken into account. Using mean and variance of historical spot-price from Nordpool, the joint Swedish- Norwegian electricity exchange, could be one solution to do it. Modeling it otherwise can be difficult because of hydropower's dependency on natural conditions and its effect on spot-pricing.

16.4 CONCLUSIONS

The new situation should be seen as an opportunity rather than a threat. New trends of increased competition, increased complexity of the business environment and internationalization are part of this new reality. The change calls for new methods and tools. One new element introduced by deregulation is increased risk.

16.4.1 Future of El-Ex

The volume of spot trade jumped when deregulation, and especially lifting of resale restrictions, was introduced. The main reason was that the current bulk power contracts didn't have any limitations based on energy but just on power. This encouraged short-term trade around the power levels where energy prices changed. Most of the trade is still done on a bilateral basis. Buyers feel that it is easier to use old contacts and buy directly from a producer. Producers feel that they cannot sell energy to an unknown buyer, as it could lead to a situation where a producer sells at a price lower than it would get in a long-term contract with that same customer. Bilateral trade is efficient enough at the moment, as the number of active parties in the market is not very large.

Increased competition will increase risks in utilities. When the spot market has enough liquidity, maybe 70% of electricity will be bought with long-term contracts, but the rest will bought with shorter (< 1 year) contracts or from spot-markets. Spot-price expectations will strongly influence the prices on longer contracts. Longer-term contracts involving a large fixed cost portion will no longer be as attractive as before to a utility, because uncertainty over the customer base will bring volume risk to bulk electricity buying. The only way to totally remove both volume and price risk is to sell energy on the same terms as bulk energy is bought. On the other hand, margins will likely be quite low and competition for customers willing to pay the market price and a margin will be very intense.

Producers want an adequate return-on-investment and buyers want to get their energy as economically as possible. Both will choose a risk level that suits them. These two points and the method used to calculate penalties for gaps between buying and consumption affect the need for spot trade. As rules will become established and knowledge increases, the number of participants is likely to rise. When competition, both by domestic and foreign companies, intensifies at the same time, more stress is put on an efficient marketplace. This will strengthen the position of the electricity exchange.

The importance of the exchange is linked to its volume of trade. Volume is not likely to rise until foreign companies start trading on El-Ex and, more importantly, importing and exporting energy becomes reasonably priced. Increasing volume solely by Finnish participants is a difficult issue: more buying and selling of energy should be done on the exchange, but volume is too low to provide a reliable source of supply. Because of this lack of liquidity, a participant cannot take the risk of trusting that all its desired transactions can be done on the exchange.

In the future, the increasing number of participants, tightening competition and bigger variation in the quantity of energy offered in the spot-markets due to increased significance of Norwegian hydropower will likely turn more spot trade to exchange. The bilateral trade alternatives will become too numerous to deal with and the luxury of paying more than competitors will not be available anymore. However all this is linked to easier and cheaper import and export of electricity.

16.4.2 Participants' needs in the future

Participants in an electricity exchange can be classified in many ways, but in the following they are classified as 1) producers, 2) utilities or other entities buying bulk energy and selling it to consumers, 3) consumers and 4) speculators. If used properly, the exchange brings many advantages to producers, utilities and consumers. Speculators are a totally new group in the Finnish electricity market, but they may help to increase information efficiency, that is, help prices reflect all available information without any delay.

All participants will have to deal somehow with the risks involved in trading energy. Before deregulation, risks were simply tranferred down to the next one in the chain. Producers had a special clause about price changes: when fuel prices rose, utilities simply raised prices the next year. The exchange offers new possibilities for price risk management, as risks are priced in the derivatives market.

The producers' biggest, yet unsolved problem is the prediction of sales and therefore the amount of electricity that should be produced. Trading in El-Ex ends 2 hours before the actual hour of consumption.Because only 20 % of Finnish production is hydropower, for which the power level can easily be adjusted, this is a major problem. For the same reason Nordpool's method of trading, periodical clearing of offers, is very unfavorable for Finnish participants as a trading method for the Scandinavian electricity exchange. The major problem is the interaction of long-term contracts with open supply and spot-trade. Some possible solutions to the problem are presented in the following.

*solutions based on a contract between a seller and a customer

- Customer has to notify open supplier of any fixed deliveries well before trading in the exchange ends

- Customer resigns his right to resell energy

- The change in energy bought is limited to a certain amount

- In a long-term contract the amount of energy at each power level is limited

*solutions based on energy balance counting system

- Penalties and compensations for differences between production/consumption and sold/bought quantities are modeled to fix the problem

*solutions based on generating technology

- The generating plants are made more flexible.

*solutions based on new management tools

- Market price is taken as a given factor and the amount of energy demanded at particular price level is calculated

The above list is not comprehensive, but it tries to convince the reader that the issue will be solved somehow. Some solutions may co-exist and others are, if not impossible, at least improbable

.Producers will need better tools to calculate the profitability of a single contract. As an alternative source for acquiring electric energy is always present, new and more detailed bulk energy contracts will need to be composed. Expectations of future spot-price-level will affect the price level of long-term contracts.

When the Scandinavian electricity market is in operation, the fluctuations in price are likely to become more random due to increased hydropower and its dependence on natural conditions. This will put more stress on both price prediction and planning of production. These two are inseparable, as in the spot-market the price will be the signal used to plan production.

An electricity utility will have to adopt the same tools and practices already in use in other industries where intense competition is a reality. Systems that are used elsewhere to minimize stocks and total costs of purchasing can be adopted to the managenent of energy purchasing/production and selling. The customer should become the focus of activities and systems to support it are needed. A utility can optimize both the purchasing and selling structure of energy in an attempt to maximize its margin.

As competition has been introduced, consumers have more choice than before. The spot-market increases fluctations in prices. These demand for a system to take advantage of these without increasing the effort needed by the customer. A tool to optimize timing of consumption is the first to be developed.

Speculators live on price changes. The participants have to have different expectations of future prices, as this increases the volatitily, the uncertainess of the future prices. This allows speculators to operate in the market. The speculator has to have good sources of information, as it is his tool in the market.

17 A METHOD FOR SHORT TERM ELECTRICITY SPOT PRICE FORECASTING

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17.1 INTRODUCTION

In Finland, the electricity market was de-regulated in November 1995. For the electricity purchase of power companies this has caused big changes, since the old tariff based contracts of bulk power supply have been replaced by negotiated bilateral short term contracts and by power purchase from the spot market. In the spot market, in turn, there are at the present two strong actors: The electricity exchange of Finland and the Nordic power pool; which is run by the Swedish and Norwegian companies. Today, the power companies in Finland have short term trade with both of the electricity exchanges.

The aim of this chapter is to present methods for spot price forecasting in the electricity exchange. The main focus is given to the Finnish circumstances. In the beginning of the paper, the practices of the electricity exchange of Finland are described, and a brief presentation is given on the different contracts, or electricity products, available in the spot market. For comparison, the practices of the Nordic electricity exchange are also outlined.

A time series technique for spot price forecasting is presented. The structure of the model is presented, and its validity is tested using real case data obtained from the Finnish power market. The spot price forecasting model is a part of a computer system for distribution energy management (DEM) in a de-regulated power market.

17.2 THE FINNISH ELECTRICITY EXCHANGE

The Finnish electricity exchange El-Ex Oy started 16.8.1996. The main commerce concerns near future, short term contracts, but there is a rising interest in longer time spans too. Partakers are producers, distribution utilities, sellers, brokers as well as large end-use buyers. El-Ex has 47 members, of which eleven are Swedish and two Norwegian (situation in summer 1997). Trade is continuous (open hours are banking days 10.00-17.00), and based on offers given either electronically or by phone. Transaction takes place when a sell and a buy offer meet, and the next offer will probably have another price. All offers are anonymous. The smallest volume of trade is 1 MW of power physically delivered at a given hour (1 MWh). All contracts are combinations and multiplies of this basic element.

One-hour spot contracts cover the nearest week (168 h). Their trade is closed two hours before the hour concerned. During these two hours information about the transactions is delivered to the power balance accounting organizations. Market making is continuous from 10.15 am to 5 p.m. covering the next 24 hours. In other cases, market making is conducted on a request basis. In order to guarantee the spot market, the market maker quotes two way prices in steps of five MW's. The spread of these prices is normally 20 per cent of the bid for spots.

For the following 24 weeks the hours forwards are grouped together to form one-week contracts. For these, there are three alternatives:
- Basic week consisting of all hours (168 h)
- Day week (07.00-22.00 Monday through Friday; 75 h)
- Night week (night-time and week-ends; 93 h)

Market making covers the four nearest Basic Week forwards with a spread of 40 per cent of the bid. Trade of the rest of the Basic week forwards expiring within the nearest six months is conducted on a request basis. For the remaining 28 weeks of a one year period there are 4-week blocks consisting of Basic weeks only. There are also two seasons, a summer season (weeks 17-44) and a winter season (45-16).

El-Ex vs NordPool

The Swedish-Norwegian electricity exchange, NordPool, has been operational a few years longer, and is already well established. In 1996 about 16% of the total consumption in Norway and Sweden was delivered via the NordPool spot market. NordPool has 127 participants, including some Finnish and Danish members.

In NordPool the spot-market concerns the next 24 hours. Due to transmission bottlenecks, there are several bid areas. If transmission capacity between two areas for a given hour is exceeded, different price areas will be formed with different area prices. The spot price(s) will be set the day before, at the intercept of the demand and the supply offers for a given price area. All transactions in a price area will have the same price. Only spot trading leads to physical delivery. The future contracts at NordPool are of a fiscal character, with a daily financial settlement of position.

NordPool futures have a similar time build-up as El-Ex products. One-week contracts for 4 to 7 weeks, after that 8 to 11 4-week blocks, the weeks having the same threefold branches as El-Ex with day-time hours being one hour later. NordPool has 3 to 6 seasons contracts, three seasons to a year.

The Swedish-Norwegian market and its production structure differs largely from the Finnish one. Almost all electricity in Norway and half of Sweden is produced with hydro power, while the other half of Sweden's electricity is produced with nuclear power. The installed hydro power capacity easily meets the hourly power demand, but the problem can be the sufficiency of energy. The main factor affecting the prices in NordPool is therefore the current and future water situation.

Finland has nuclear, hydro and thermal back-pressure power as its base production. During high demand periods (winter, workdays) their capacity is not enough and condensing power plants must be run, at a much higher energy cost. Wholesale tariffs have, up to the present, been priced accordingly. Electricity at high demand is more expensive than at low demand period. The synergy from a united Nordic exchange could be extensive, considering how well the two systems complement each other the one being power and the other energy limited. Both exchanges use the same computer system, so trade technology isn't an obstacle. A united exchange should, however, have products suited for both production systems.

Six Finnish El-Ex members are also partaking in NordPool, while El-Ex has some Norwegian and Swedish players. Therefore El-Ex prices follow NordPool prices within a reasonable spread (Fig. 73). Different trade practices with regard to price and transaction determination, as well as the transmission cost between Sweden and Finland, are to be taken into account when comparing prices or planning electricity arbitrage between the two exchanges.

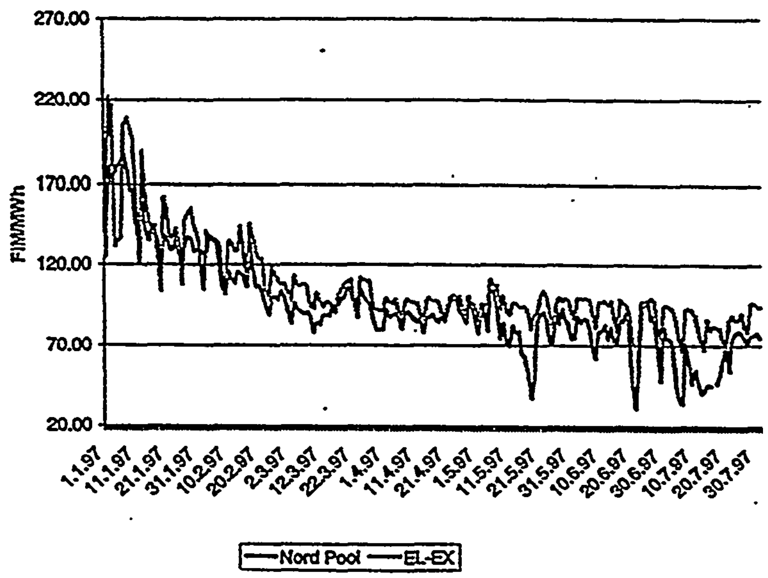

Fig. 73. El-Ex vs. NordPool (Stockholm area) prices 1.1.1997 -31.7.1997.

17.3 NEED FOR SHORT TERM PRICE FORECASTS

Participants in the electricity market have contracts, production, obligations etc. Many of their choices are tied, and many depend on uncontrollable factors. Some of these, like temperature, have a signifant impact on consumption and production, but are hard to forecast, with forecasts getting more reliable the shorter the gap between prediction time and realization time. Participants optimize their actions in the electricity market using short term (one day to one week) forecasts. One important factor in optimization is the spot price of electricity, another one is power demand. The better the forecasts, the better the optimization result.

Optimization is usually made several days before the actual delivery hour, and as time evolves, unexpected factors affecting production or consumption may emerge. This leads to a situation of imbalance. Thus, market participants have a need to reoptimize their actions, perhaps making plans to buy or sell power in order to reach the balance. The important questions are: when, where and how much? Hour contracts enable participants to fine-tune their energy purchase accurately and as close to the actual production hour as possible. But should the participant make the spot deal now, three days before the hour in question, or wait till tomorrow ?

17.4 THE SHORT TERM FORECASTING METHOD

El-Ex hourly spot price variation is very much similar to hourly load variation. This can be explained by the observation, that the generating costs largely depend on the production mix, which in turn bears direct correlation to the total demand. The forecasting method proposed here is a general use modular time series approach, with detached regression analysis. For managing hourly forecasts, it is assumed that the spot price follows a day, a week and a year cycle.

The modular time series approach is based on days as entities. Suitable comparison days are automatically hand-picked from the history database. A day belongs to one of the three classes: workday, eve (=Saturday) or holiday. Each day further belongs to one of the seven weekday classes. This results in having day type categories. But unlike other similar day type approaches, which have libraries with normalized, ready profiles (made z years ago), our method just has information of which day belongs to which category. This allows for a dynamic approach. The hand-picking of comparison days is done according to a given logic. For example, when forecasting a normal Tuesday, the logic is to choose only workdays(=not special holidays) and Tuesdays, Wednesdays and Thursdays.

Another restraint for choosing comparison days is the seasonal distance. Suitable days for a day in January would be days from December to February. The seasonal restraint varies according to season. The model has the maximum number of comparison days to be picked as a parameter. As comparison days are chosen in the most desired order, the parameter forms an additional constraint.

The next step is regression analysis, which is done dynamically with an on/off-option, and with regard to one regressor only. This regressor is temperature, which in Finland is the main factor explaining load variation. Because both temperature and loads follow the same day cycle, there is a serious skewness in the regression data when mixing all hours together. This easily results in distorted regression coefficients. For this reason, our method is based on comparison of the hours, which have about a similar load level only.

Day-time regression analysis is done with daytime hours between 12.00-14.00 while for night-time hours 02.00-04.00 are used. The daytime and night-time regression values are valid for 06.00-22.00 and 22.00-06.00 respectively. If a high enough temperature correlation is found, the values will be corrected to suit the forecasted regressor values.

The forecasted value for a given hour actually is an average of the the comparison days' values for that same hour of day. In many cases the extreme values are affected by measurement errors or one-time occurencies, which are unpredictable and not forecastable. It is often advantageous to chop off the most extreme values from the data before the forecasting. Our model calculates the standard deviation of the unchopped data value group. The deviation values can be used for a confidence interval.

Forecast results

First a calculation was made to extract and calculate the highest, lowest and weighted average spot prices for each hour from El-Ex reports. Days without spot prices for each hour (no deals or data extraction error) are dropped from the data history base.

Test forecasts were made using both high and average prices, and with temperature correction routines both on and off. For each forecasted day, history data up to the day before was used. Measurements from the city of Turku were used as temperature data, with measured temperature values being used as forecasts.

Case 1: 1-31.12.1996.

Days 10-12.12 and 15.12 were missing. Special holidays: Friday 6.12 (Independence Day) and Tuesday-Thursday 24-26.12 (Christmas). Temperature correlations exceeded the given acceptable value of 70% only a few times. Day-time correlation was high enough 19, 20 and 23.12, while the respective night-time dates were 7, 25, 26, 27 and 29.12.

Errors are presented as an average of hourly relative errors:

$$Error = \frac{1}{i}\sum_{i}\frac{|forecast_i - actual_i|}{actual_i} \quad ; \forall\ i \in hours\ in\ question. \qquad (22)$$

Error characteristics are presented in Table 13, and in Fig. 74. Temperature correction improved forecast accuracy by about 30-40 % for hours concerned, and by 8 % on the average. It is worth noting how well special holidays are handled: they are forecasted quite accurately and they themselves don't interfere with the following forecasts. On the other hand, the reaction to a sudden, large price change is slow. The temperature correlation grows for daytime 19-20.12 to a relative high value, telling us that a temperature drop is the reason behind the price rise.

Case 2: 27.4- 5.5.1997.

A special holiday: Thursday 1.5 (May Day). No temperature checking was made due to lack of data. Table 14 shows different error characteristics. The errors are on average much smaller than in December, explained by the less volatile price behaviour. Fig. 75 shows the same time span graphically.

Table 13. Forecast errors in the December 1996 case. Forecast done both with and without dynamic temperature analysis and correction. Forecasts made for both average spot price and for highest hourly spot values.

Average errors	*Forecasting method*	*1-31.12 not 10-12,15*	*19,20,23.12 days*	*day-time*	*7,25-27,29.12 night-time*
Average spot price	*Normal forecast*	*8.4%*	*20.1%*	*26.7%*	*4.3%*
	Temp.analysis &correction	*7.7%*	*15.0%*	*19.0%*	*2.5%*
	Resulting improvement	*8.3 %*	*25.4 %*	*28.8 %*	*41.9 %*
Highest spot price	*Normal forecast*	*9.1%*			
	Temp.analysis &correction	*8.7%*			
	Resulting improvement	*4.4 %*			

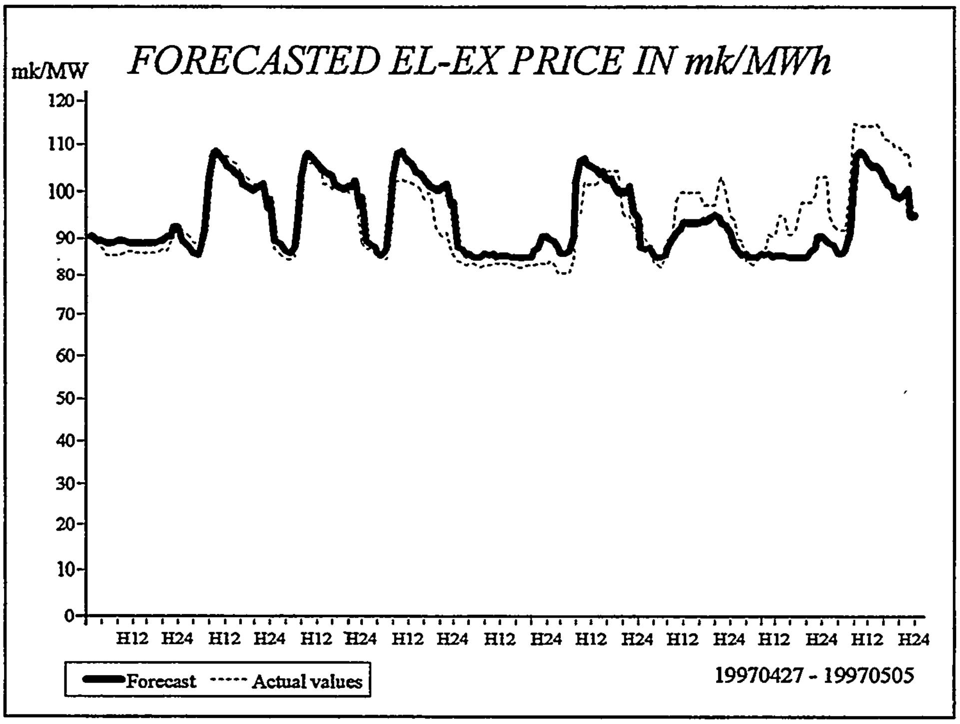

Fig. 74. Forecasted and actual spot prices in between April 27th and May 5th.

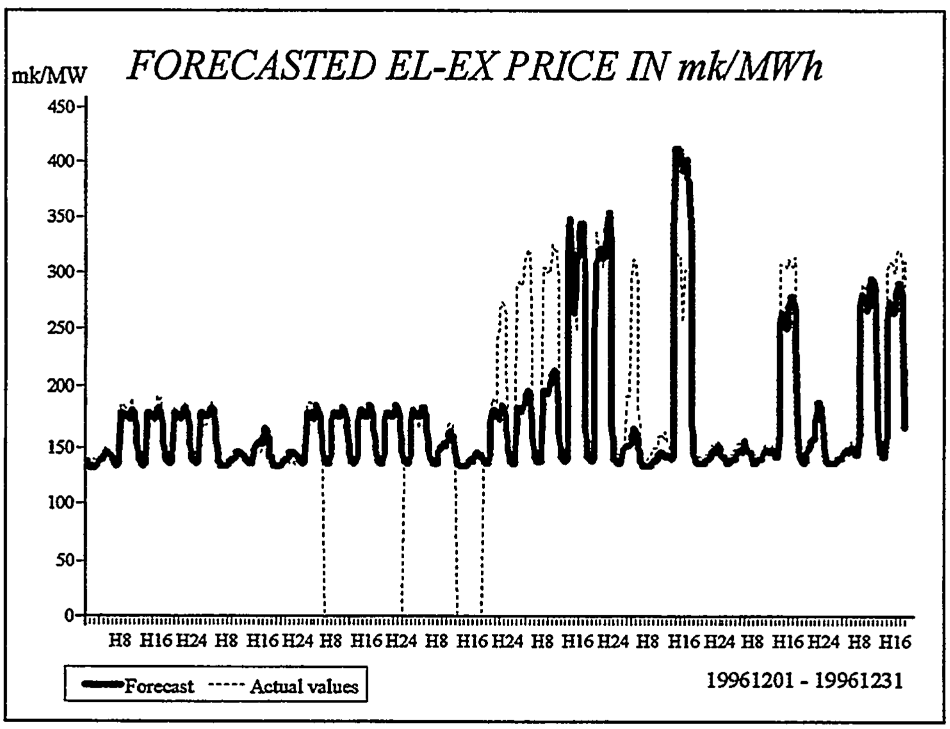

Fig. 75. Forecasted and actual spot prices in December 1996. Forecast method had temperature correction on.

Table 14. Forecast 27.4-5.5.1997. Different error characteristics for forecasts of average and high values of hourly spot prices.

27.4-5.5.97	***Average abs. relative error***	***Median abs. relative error***	***Max hourly relative error***	***Min hourly relative error***
Average spot price	4.4%	3.3%	14.5%	0.0%
Highest spot price	4.2%	3.5%	15.7%	0.0%

17.5 CONCLUSIONS

Spot price of Finnish and Nordic electricity exchanges have so far been reasonably stable. NordPool as well as the Finnish wholesale tariffs have a stabilizing influence on the El-Ex spot price, although NordPool high/low prices also have a suction effect. El-Ex spot price exhibits the same cycle as the total power demand, and is well suited to a time-series based forecasting method. Although spot price depends on temperature, the dependency is to a substantial degree reflected by large temperature fluctuations only.

In this chapter, a new method was presented for electricity spot forecasting. The method was shown to be easy to use and accurate enough for most practical purposes. The strength of the method is, that it does not require any input data except for the average past spot prices and outdoor temperatures. The method is an integral part of a large computer system for distribution energy management (DEM) designed to support the retail selling and power purchase of a power trading company in a de-regulated power market.

18 AN AUTOMATIC FAULT MANAGEMENT MODEL FOR DISTRIBUTION NETWORKS

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18.1 INTRODUCTION

An automatic computer model, called the FI/FL-model, for fault location, fault isolation and supply restoration is presented. The model works as an integrated part of the substation SCADA, the AM/FM/GIS system and the medium voltage distribution network automation systems.

In the model, three different techniques are used for fault location. First, by comparing the measured fault current to the computed one, an estimate for the fault distance is obtained. This information is then combined, in order to find the actual fault point, with the data obtained from the fault indicators in the line branching points. As a third technique, in the absence of better fault location data, statistical information of line section fault frequencies can also be used. For combining the diffenrent fault location information, fuzzy logic is used. As a result, the probabililty weights for the fault being located in different line sections, are obtained.

Once the faulty section is identified, it is automatically isolated by remote control of line switches. Then the supply is restored to the remaining parts of the network. If needed, reserve connections from other adjacent feeders can also be used. During the restoration process, the technical constraints of the network are checked. Among these are the load carrying capacity of line sections, voltage drop and the settings of relay protection. If there are several possible network topologies, the model selects the technically best alternative.

The FI/FL-model has been in trial use at two substations of the North-Carelian Power Company since November 1996. This chapter lists the practical experiences during the test use period. Also the benefits of this kind of automation are assessed future developments are outlined.

18.2 AUTOMATION SYSTEM INTEGRATION

An efficient fault management automation system requires close integration of substation telecontrol (SCADA), network automation, protection relays and AM/FM/GIS systems. In the solution presented in this paper, the integration of substation telecontrol and protection relays, is based on the Inter Bay Bus (IBB) utilizing the Carrier Sense Multiple Access / Collision Detection (CSMA/CD) principle (Figure 76). This enables:

- spontaneous data transfer of events from bay level to station level
- more than one station level device being connected to the IBB
- horizontal communication which enables flexible functions such as station intelocking, load shedding etc.

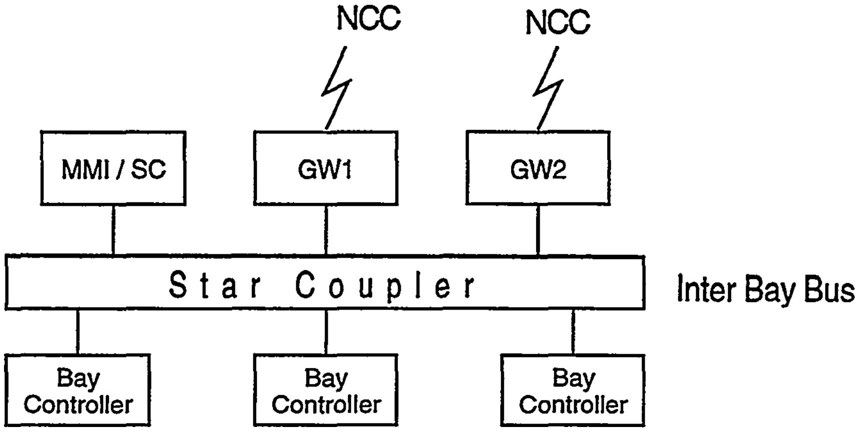

Figure 76. The principle of the integrated station automation and relay protection. NCC is a network control centre, SC is the station controller, MMI is the man-machine interface, GW is the communication gateway and the Bay Controller is the integrated protection and control unit.

The substation automation system can be locally operated with a substation controller (SC) connected to the communication gateway (GW) via the Inter Bay Bus. The user interface and the operation functions of the SC are the same as those that are available at the control center level. The SCADA software in the control center is also directly applicable in the SC computer and vice versa.

The tools for systems updating and configuration are the same for the SC and network control centre (NCC) applications. A significant system improvement has been gained by the possibility of implementing higher level logic at the substation level also, so that the basic level functions are utilized as basic elements. In addition, in the integrated protection and substation control system, the alarm and annunciator function is allocated to the Station Controller (SC).

The data transmitted from the Gate Way to the NCC includes all the information processed in conventional SCADA systems. In addition some newer applications are possible. Among these are the remote setting of relay parameters and remote monitoring of circuit breaker operation times and service limits. The protection relays also register the fault currents. The bay level functions include relay protection, autoreclosure automatics, remote reading of status and measurement data and the control of circuit breakers and other possible objects. These functions can be implemented with an integrated protection and control terminal.

The protective modules transmit the measured current and voltage values via the serial bus to the station level unit (SC). Additionally, these modules store the information in a fault situation. This information includes the measured fault currents, the type of fault and the phases involved.

The integration of the AM/FM/GIS (Automated Mapping /Facilities Management/Geographic Information System) and the substation SCADA system is illustrated in Figure 77. Data exchange works as a two-way interactive communication. The interface is based on a data vector. It can be controlled by either one of the systems, although the main data flow is from SCADA to AM/FM/GIS. The information transferred includes:

- spontaneously the changes of the switch positions, data on the operation of the transformer on-load tap-changer and information on relay operations.
- spontaneously the values of analog measurements in case their changes have exceeded the dead band (load flows of substation transformers, busbar voltages, feeder currents, weather measurements such as wind velocity and direction, air humidity and outdoor temperature).
- the 15 minute average values of analog measurements
- the 1 hour average values of analog measurements

The main task of a SCADA system is to provide a real time interface to high voltage / medium voltage substations and to the remote controlled points in the medium voltage distribution system. The role of the AM/FM/GIS system is to form a data bank at the disposal of a large variety of network automation, operation and planning functions. It is also used for real-time presentation of the network connections. Here the switching state of the network is represented by different colors, either according to the substation transformers, or medium voltage feeders of the MV/LV transformer circuits. Coloring is carried out dynamically. As a result, whenever the position of the switchgear is changed, the line sections affected change color automatically and with practically no delay.

In the most advanced version of fault management automation, the data needed for the FI/FL model is collected in real time from the AM/FM/GIS system before executing the model. This data includes the technical data of the feeder concerned in the topology prevailing before the fault occurred. In addition the technical computation results for fault and load currents, as well as the computed voltages in feeder locations, are obtained. The substation telecontrol system provides the dynamic information, such as fault currents and load currents measured at the substation and the line switch positions in the feeder concerned.

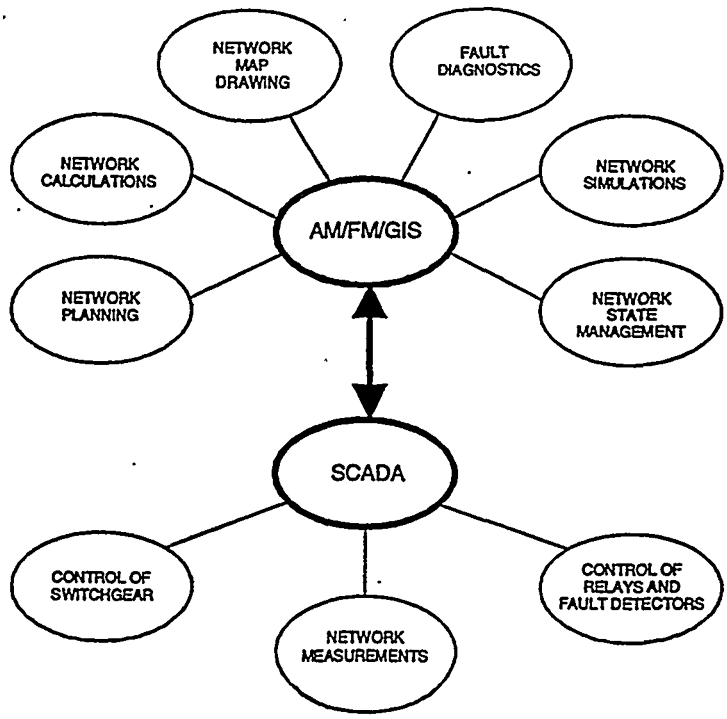

Figure 77. The integration of a substation telecontrol system (SCADA) and a distribution data management system (AM/FM/GIS).

The FI/FL module works as an integrated part of the substation telecontrol system. After the FI/FL module has been started, the communication is between the SCADA system and the network controlled points only. In this phase the commands sent by the SCADA include the line switch close/open operations. At every step of the fault management process, the status of the feeding circuit breaker at the substation is also checked, in order to detect possible closings against a faulty line section.

In order to make the commissioning of the FI/FL module easier, a lower integration degree solution has also been developed. Here the AM/FM/GIS system has been replaced by input data flat files, which are resident in the SCADA system. For each feeder included in the fault management automation, there is an individual input file. This arrangement requires, however, that the topology of the feeder must be kept fixed, if full benefit of the automation is desired.

18.3 FAULT LOCATION TECHNIQUES

In the fault location part of the FI/FL model, three different sources of information are used:

1) the computed fault distance
2) the data from the fault indicators in the line crossings
3) the statistical fault frequencies of different line sections

For obtaining the computed fault distance, the measured and the computed fault currents are compared. As a result, the estimated distance of the fault from the substation is obtained. This distance is then, in turn, compared to the network diagram, and the possible fault locations are shown on a graphical display of the distribution network (Figure 78).

When a fault happens, the operation of the fault distance computation is as follows:

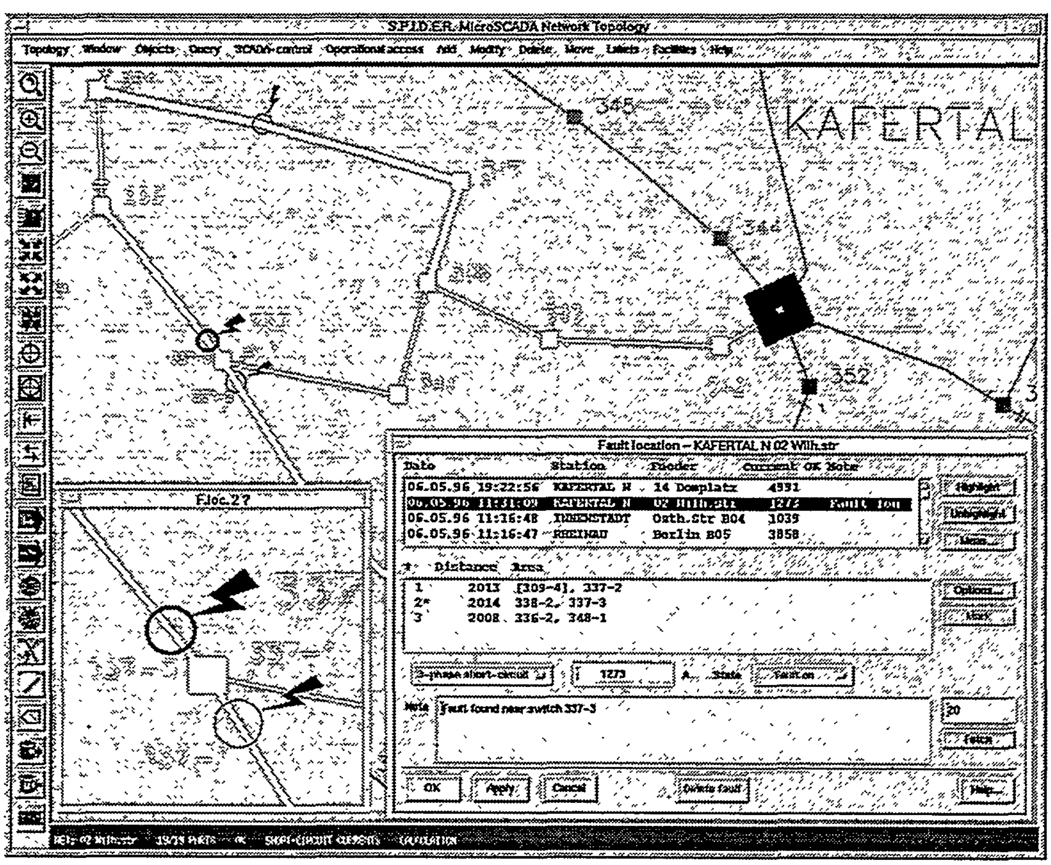

Figure 78. An example of the graphical display of the automatic system for fault location, fault isolation and supply restoration. The most likely fault location is shown using the symbol for lightning.

1) The protection relays store the fault information (currents, fault type, phases involved, feeder involved, information on reclosing steps).

2) The SCADA system adds some more information to the received fault data (measured feeder load current and the load flow of the substation's main transformer).

3) The AM/FM/GIS system computes the corresponding fault currents of the feeder concerned and compares the measured data to the computation results. Before the comparison, the load currents, superposed on the fault currents, are compensated for.

All the data needed for fault location computation is stored in the working memory of the AM/FM/GIS system. The purpose of this arrangement is to make the processing fast enough to meet the practical requirements.

The main factors affecting the accuracy of short circuit fault location are the load current superposed on the measured fault current and the fault resistance /26/. The load current before the fault occurred is known by the measurements of the substation telecontrol system. This makes it possible to implement models for load current compensation in the fault location system /26/. In the case of two or three phase faults, the maximum fault resistance depends on the fault current and the maximum arc length. Consequently, it is possible to estimate the maximum value of the fault resistance. In practice, however, the fault location computation is made with the assumption of zero fault resistance. This gives the estimated maximum fault distance. Because of the fault resistance, the actual fault point must then be closer to the substation.

According to practical experience in rural overhead line networks, the average error in fault distance estimation has been about 1.2 km. For close faults the absolute errors are smaller, whereas for distant faults they are larger, respectively. This degree of performance is good enough for defining the faulty line section between two isolating disconnectors. At present, however, the fault distance computation works for three and two phase short circuit faults only. A technique for earth fault distance computation is in the development phase. This technique is based on the analysis of transients, which occur at the initial moment of a single phase to earth fault.

When analyzing the readings of the fault indicators one has to take into account their possible misoperations. It is also often the case that only a part of the line sections concerned are equipped with fault indicators. These problems can be mitigated by statistically combining the indicator readings. This is however a complicated task since the dynamically changing network connections must be allowed for. In the automation model developed, the network topology is first analyzed and the line sections are classified according to the fault indicator data available. The classification divides the line sections into three different classes:

1) the line sections where the fault might be, provided that the indicator readings are correct

2) the line sections where the fault cannot be, provided that the indicator readings are correct

3) the line sections which do not belong to the first two classes

In the next phase, statistical weights are computed for the probability of the fault being located in the different line sections. In this computation, the reliability of the fault indicators is taken into account.

The third source of information is the statistical fault frequencies of different line sections. This data is useful especially if the network is a mixture of overhead and underground line sections. In the latter ones the fault frequencies are substantially lower than in the former ones.

The final phase of the fault location procedure is to combine the information from different sources by fuzzy logic. The statistical fault frequencies of different line sections are, however, regarded as weak information when compared to the other fault location techniques. Hence, they are not taken into account if both fault indicators and computational fault location are available. The final result of the fault location module is the probability weights for each line section. These weights express the likelihood of the fault being located in the line section concerned. In the next step of the fault management procedure, this data is submitted to the fault isolation and supply restoration model.

18.4 FAULT ISOLATION AND SUPPLY RESTORATION

Once the fault location has been analyzed by the FL submodule, the automatic function for fault isolation and supply restoration (FI submodule) is executed. In the course of this procedure, the AM/FM/GIS system provides a graphical interface which tracks the progress of the fault management process. The positions of the switches are shown on a real time basis, and the topology of the network is continuously displayed by dynamically coloring the line sections connected to each other.

The control of the network switches is done in such a way, that the line is processed zone by zone in the smallest possible remote controlled sections. After every reclosing of a line switch, the status of the feeding circuit breaker is checked, and if there has been tripping, the line section concerned is regarded as a faulty one. Althought the logic of the FI/FL model is based on an assumption that there is only one fault, the automation system is able to handle a situation of multiple faults in different line sections.

The operation of the FI model is optimized so that the number of outages experienced by the customers connected to the faulty line is minimized. For this, there are two alternative approaches, depending on whether the faulty line section will be verified by trial switching or not. In the trial switching mode, the FI model first tries the line sections with the highest fault probability. When the faulty line section is encountered, it is isolated, and the remaining sections are energized. The trial switching mode actually performs a delayed autoreclosing. This mode is recommended in the cases, where there is some degree of uncertainty in the fault location, or where it is desired that the traditional delayed reclosing by protection relays be replaced by a zone-by-zone reclosing.

In the second mode, the aim is to avoid the trial switchings. Here the line sections are energized starting from the smallest fault probability and when only one section is left, the procedure is stopped. This mode is usually used only if a full reclosing procedure is first performed by the relays. To be effective, this mode also requires a good knowledge of fault location. In practice this means, that there must be fault indicators mounted at the line crossing points where the remote controlled switches are.

The FI model first tries to energize the line section by section from the initial feeding direction. For those sections which can not be energized in this way, a reserve connection is used. Before the coupling, the capacity of the reserve connection is checked for thermal load carrying ability and for the maximum voltage drop. Also the settings of the protection relays of the feeding circuit breaker are checked in order to ensure relay coordination. It is especially important to make sure, that in the case of a two phase short circuit fault in a distant line location, the fault current is high enough to trip the relay.

When using the reserve connections, the network topology is optimized by the FI-model so that the voltage drop is as small as possible. In distribution systems, where voltage reduction is the limiting factor for the load carrying capacity, this strategy directly leads to the most efficient use of network capacity. This is the case in overhead line networks in rural and suburban areas. In urban systems, the limiting factor is usually not the voltage drop, but the load carrying capacity of the reserve feeder. However, in this case also the selection of the reserve connection according to the voltage reductions tends to divide the restored load equally between the capacities available.

The main benefit of the automatic fault isolation and supply restoration is the reduced outage costs to the customers. These savings result due to the smaller risk of trial switchings which cause additional interruptions in the supply. Automation also makes a more rapid fault restoration possible and hence shortens the outage times. This is the case especially if the reserve connections only have a limited capacity. In this case, the computer model allows for a quick check of the technical constraints of the reserve connections.

18.5 PRACTICAL EXPERIENCES

The FI/FL model presented in this paper has been in test use at two substations of the North-Carelian Power Company since November 1996. At the present there are altogether three feeders under automatic control.

When installing the pilot system, a test series with artificial faults thrown on the real distribution lines was performed. In initial tests, it was found that the functions, which check the breaker status after line switch closing, were unreliable due to the synchronizing problems. To solve this problem, these functions were changed from event based structure into a procedural solution. After the change, a new test series with 10 faults was executed with full success. After the test series, the system has been in use waiting for real faults to occur. By May 1997, half a dozen faults were encountered, all of which were cleared successfully.

At present, the FI/FL model can be run only for one feeder at a time. After the execution of the model, the feeder concerned is locked, so that the model has to be reset by the operator, before it can be activated for the same feeder again.

In order to collect additional practical experience, the test use will be continued through the next thunderstorm season. In the end of this year, the application will be extended to cover new feeders in several substations. At the same time the model will be further developed in order to make it a commercial product. The commercialization mostly includes the development of a family of line switch control functions, corresponding to different types of remote terminal units common in the field. In addition, some new tools are being developed for the updating of the input data.

According to the experience gained, the FI/FL model is a very effective tool in cutting the customers' outage costs. Compared to the plain line switch remote control, the additional reduction is 30...40% of the remaining outage costs. The reduction is due to more effective fault location and a smaller number of trial switchings. For instance, in a typical rural or suburban feeder with overhead construction, the annual outage costs per 1 MW of peak power are as follows (1 FIM = 0.2 USD):

- 145 000 FIM in the case where there is no automation or remote control
- 97 000 FIM in the case with one remote controlled line switch station per feeder (3 or 4 switches),
- 58 000 FIM in the case where the FI/FL model is also used

The conclusion of the trial period is, that the FI/FL module should be used at all the feeders, where there are remote controlled line switches available. The costs of the model are only marginal compared to the expected benefits.

18.6 CONCLUSIONS

An automatic computer model, called the FI/FL model, for fault location, fault isolation and supply restoration was presented. The model works as an integrated part of the substation SCADA and the medium voltage distribution network automation systems. In the model, three different techniques are used for fault location: distance computation, fault indicator data and statistical information of line section fault frequencies. Once the faulty section is identified, it is automatically isolated by remote control of line switches. Then the supply is restored to the remaining parts of the network. If needed, reserve connections from other adjacent feeders are also used.

The experiences with the trial use period of the FI/FL model have shown that this kind of automation has become practically possible. What is needed, is a good integration of a substation telecontrol system with network automation. To get the full benefits of the automatic switching system, a relatively wide use of line switch remote control is also required. In this case, the costs of the model are only marginal compared to the expected benefits. The final conclusion is, that automatic switching and fault location should be used at all the feeders, where there are remote controlled line switches available.

19 A METHOD FOR DETECTION AND LOCATION OF HIGH RESISTANCE EARTH FAULTS

Seppo Hänninen & Matti Lehtonen, VTT Energy, and Erkki Antila ABB Transmit Oy

19.1 INTRODUCTION

In the first part of this paper, the theory of earth faults in unearthed and compensated power systems is briefly presented. The main factors affecting the high resistance fault detection are outlined and common practices for earth fault protection in present systems are summarized.

The algorithms of the new method for high resistance fault detection and location are then presented. These are based on the change of neutral voltage and zero sequence currents, measured at the high voltage / medium voltage substation and also at the distribution line locations. The performance of the method is analyzed, and the possible error sources discussed. Among these are, for instance, switching actions, thunder storms and heavy snow fall.

The feasibility of the method is then verified by an analysis based both on simulated data, which was derived using an EMTP-ATP simulator, and by real system data recorded during field tests at three substations. For the error source analysis, some real case data recorded during natural power system events, is also used.

19.2 NETWORKS WITH AN UNEARTHED NEUTRAL

In networks with an unearthed neutral, the currents of single phase to ground faults depend mostly on the phase to ground capacitances of the lines. When the fault happens, the capacitance of the faulty phase is bypassed, and the system becomes unsymmetrical (Fig.79). The fault current is composed of the currents flowing through the earth capacitances of the two sound phases.

A model for the fault circuit can most easily be developed using Thevenin's theorem. Before the fault, the voltage at the fault location equals the phase voltage E. The other impedances of the network components are small compared to those of the earth capacitances C_e, and can hence be neglected. For Thevenin's impedance, the earth capacitances are thus connected in parallel, which leads to the model in Fig. 80. In the case where the fault resistance is zero, the fault current can be calculated as follows:

$$I_e = 3\omega C_e E \tag{23}$$

where $\omega=2\pi f$ is the angular frequency of the network. The composite earth capacitance of the network C_e depends on the types and lengths of the lines connected in the same part of the galvanically connected network. In radially operated medium voltage distribution systems this is, in practice, the area supplied by one HV/MV substation transformer.

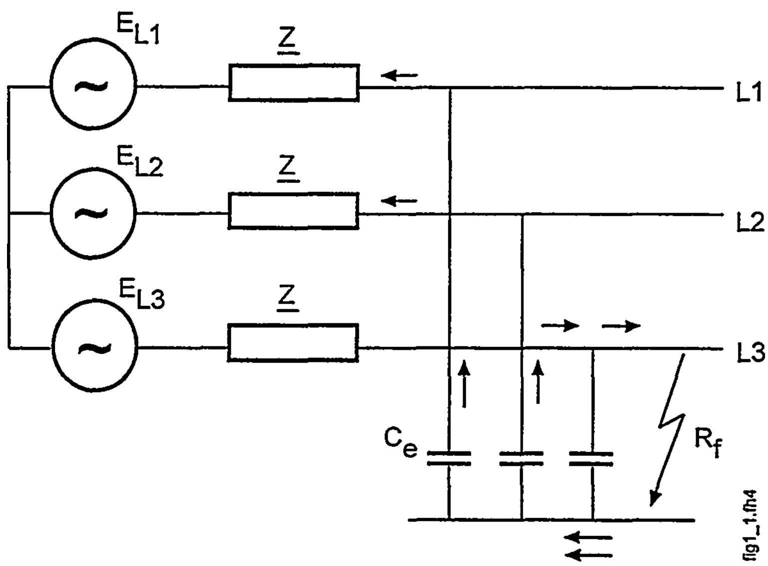

Fig. 79. Earth fault in the network with an unearthed neutral.

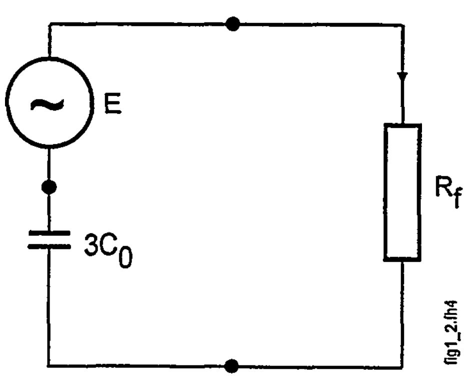

Fig. 80. Equivalent circuit for the earth fault in a network with an unearthed neutral.

In earth faults there is usually some fault resistance R_f involved, the effect of which is to reduce the fault current:

$$I_{ef} = \frac{I_e}{\sqrt{1+(\frac{I_e}{E}\, R_f)^2}} \tag{24}$$

where I_e is the current obtained from Eq. (23). In unearthed systems this does not, in practice, depend on the location of the fault. However, the zero sequence current of the faulty feeder, measured at the substation, includes only that part of the current that flows through the capacitances of the parallel sound lines. An interesting question is how the neutral, or zero sequence voltage U_0 acts during the earth fault. According to Fig. 80, this voltage is the same as that which the fault current causes when flowing through the zero sequence capacitances:

$$U_0 = \frac{1}{3\omega C_0} I_{ef} \tag{25}$$

Using equations (23) and (24) this can also be written in the following form:

$$\frac{U_0}{E} = \frac{1}{\sqrt{1+(3\omega C_0 R_f)^2}} \tag{26}$$

which states, that the highest value of neutral voltage is equal to the phase voltage. This value is reached when the fault resistance is zero. For higher fault resistances, the zero sequence voltage becomes smaller. In networks with an unearthed neutral, the behavior of the neutral voltage during the earth fault is of extreme importance, since it determines the overall sensitivity of the protection. Depending on the case, the highest fault resistance that can be detected is typically some thousands of ohms.

19.3 NETWORKS WITH A COMPENSATED NEUTRAL

These systems are also known as resonant earthing, or according to the inventor, as Petersen coil systems. The idea of earth fault compensation is to cancel the system earth capacitance by an equal inductance connected to the neutral (Fig. 81), with a corresponding decrease in earth fault currents.

The equivalent circuit for an earth fault in a compensated system, based on Thevenin's theorem, is shown in Fig. 82. The circuit is a parallel resonance circuit and if the reactor is tuned exactly to the system capacitance, the fault current has only a resistive component. This residual current is due to the resistances of the coil and distribution lines together with the system leakage resistances (R_0). Often the earthing equipment is complemented with a parallel resistor R_L, the task of which is to increase the ground fault current in order to make selective relay protection possible.

The residual current is, in medium voltage networks, typically from 5 to 8% of the system's capacitive current. In totally cabled networks the figure is smaller, about 2.3 %, whereas in networks with overhead lines solely, it can be as high as 15 %.

Using the equivalent circuit of Fig. 82, we can write for the fault current:

$$I_{ef} = \frac{E\sqrt{1+R_0^2(3\omega C_E-\frac{1}{\omega L})^2}}{\sqrt{(R_f+R_0)^2+R_f^2R_0^2(3\omega C_0-\frac{1}{\omega L})^2}} \tag{27}$$

In the case of complete compensation, the above can be simplified as follows:

$$I_{ef} = \frac{E}{R_0 + R_f} \tag{28}$$

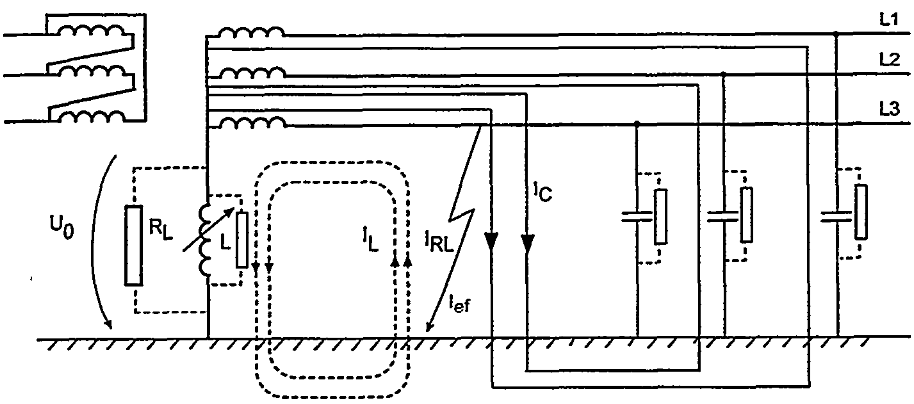

Fig. 81. Earth fault in a network with a compensated neutral. I_C is the current of earth capacitances, I_L is the current of the compensation coil and R_L is the parallel resistor used for increasing the fault current.

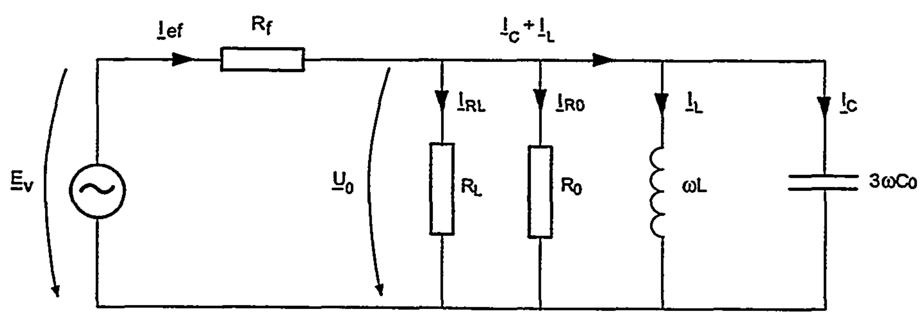

Fig. 82. Equivalent circuit for the earth fault in a network with a compensated neutral.

The neutral voltage U_0 can be calculated correspondingly:

$$U_0 = \frac{I_{ef}}{\sqrt{(\frac{1}{R_0})^2 + (3\omega C_0 - \frac{1}{\omega L})^2}} \tag{29}$$

which in the case of complete compensation, is reduced to the following form:

$$\frac{U_0}{E} = \frac{R_0}{R_0 + R_f} \tag{30}$$

For the above equations it was assumed that no additional neutral resistor R_L is used. If needed, the effect of R_L can be taken into account by replacing R_0 in equations (27) to (30) by the parallel coupling of R_0 and R_L.

As in the case with an unearthed neutral, the highest zero sequence voltage equals the phase voltage of the system. During earth faults, the neutral voltages are substantially higher in the systems with a compensated neutral than in the case with an unearthed one. Hence a more sensitive relay protection for high resistance faults can be gained in the former case.

19.4 PRESENT TECHNIQUES FOR EARTH FAULT DETECTION

In this section, the present practices for earth fault detection in high impedance earthed systems are outlined. The techniques discussed are directional earth fault relays and neutral voltage relays.

19.4.1 Earth fault protection of MV feeders

The best result for earth fault protection of MV lines in high impedance earthed systems is gained if directional relays are used. In networks with an unearthed neutral, the phase shift between the earth fault current of the faulty line and the current at the sound lines is about 180^0. Hence, the selectivity is based on the measurement principle whereas the relay settings, neutral voltage and zero sequence current, primarily affect the sensitivity of the protection only. In this case, tripping is permitted, if the following conditions are met:

- the zero sequence current I_0 exceeds the setting, and
- the neutral voltage U_0 exceeds the setting, and
- the phase shift between I_0 and U_0 is in the range $\varphi_0 \pm \varphi\Delta$
  (where $\varphi_0 = 90^0$ and $\Delta\varphi = \pm 80^0$)

A more modern characteristic is the reactive current measurement, which is met in numerical relays. In this case the tripping is initiated, if neutral voltage and reactive current $I\sin\varphi$ both exceed the threshold value. However, in unearthed systems, there is practically no difference between the performance of the two relay characteristics, since the phase angle of the neutral voltage compared to the sum current is usually fairly close to -90^0.

In resonant earthed systems, the protection can not be based on the reactive current measurement, since the current of the compensation coil would disturb the operation of the relays. In this case, the selectivity can be based on the measurement of the active current component. Often the magnitude of this component is very small, and must be increased by means of a parallel resistor in the compensation equipment. The typical characteristics of the directional relays for compensated systems are similar to those used in unearthed networks. The only difference is that the characteristics are turned by -90^0.

19.4.2 The use of zero sequence overvoltage relays

In high impedance earthed systems, the neutral voltage caused by an earth fault is practically the same in the whole supply area of the substation transformer. Also, its magnitude does not depend on the location of the fault. Consequently, a general detection of earth faults can be gained by means of a zero sequence overvoltage relay.

In overhead line networks, faults with very high resistance can appear due to trees leaning against a conductor, for instance. These faults tend to evolve gradually into a fully established earth fault. Hence, an indication of such a fault would be of very high importance. The sensitive detection of high impedance earth faults can, to some degree, be achieved by means of neutral voltage relays. In this case, the voltage threshold value taken is as low as it is possible. The lowest limit depends on the neutral voltage present during the normal operating state. In unearthed systems this usually is very small, typically around 1% of the nominal phase voltage, whereas in completely compensated networks higher values are encountered. In the latter case, the neutral voltage can be kept low by careful transposing of lines and by an appropriate setting of the compensation reactor. If the normal value varies below 2%, a recommended relay setting is 3%. In addition, a long time delay, up to 5 minutes, is needed. These settings allow for the fault detection sensitivity given in Table 15. It should be noted, however, that the settings in the example are applicable for alarm only.

The typical resistance of a tree is in the range 20 ... 80 kΩ. These figures apply in the seasons when the earth is not frozen. In the winter time much higher resistances, ranging up to several hundreds of kohms are encountered. As can be noticed from Table 15, most faults of this type are beyond the reach of the zero sequence overvoltage relays.

Table 15. The sensitivity of earth fault detection based on the zero sequence overvoltage relay. A system with a compensated neutral. U is the nominal voltage, I_c is the capacitive fault current after compensation, I_r is the resistive current of the system and R_f is the fault resistance value for which a fault can be detected.

U (kV)	I_c (A)	I_r (A)	R_f (kohm)
6.6	5	5	13
11	5	5	22
22	10	10	22
33	20	10	24
44	20	10	32
55	20	10	40

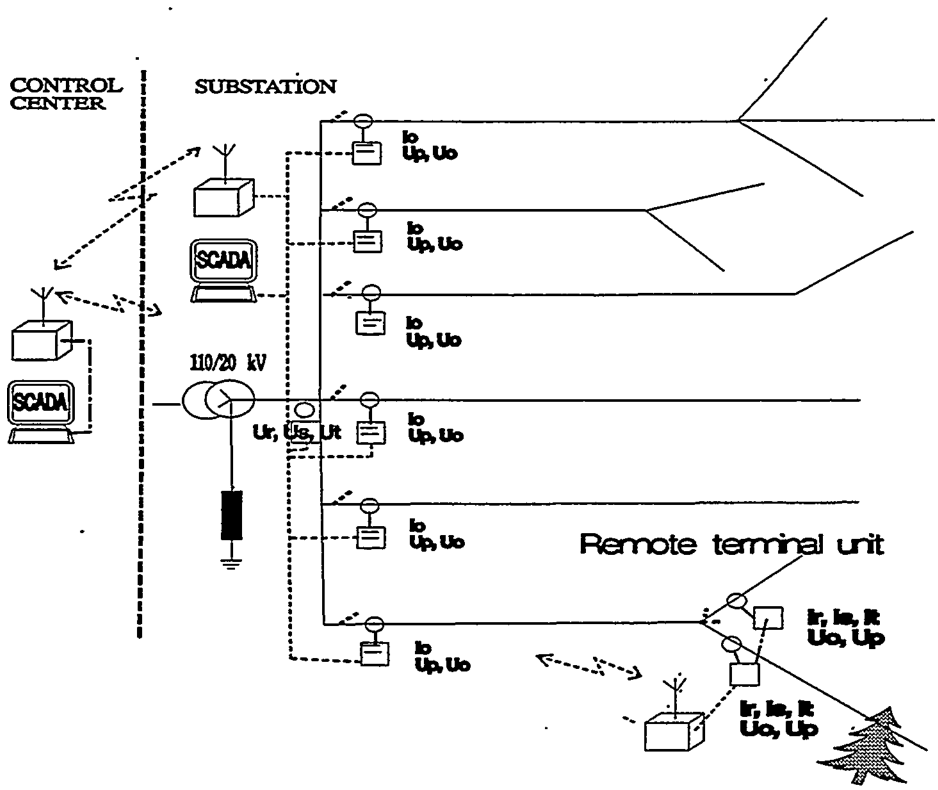

Fig. 83. The high resistance fault detection and location system.

19.5 A NEW METHOD FOR HIGH RESISTANCE FAULT DETECTION

A new method for high resistance fault detection and location, based on the change of neutral voltage and zero sequence currents, is presented in this section. The practical implementation of the method requires a close integration of the substation SCADA with modern relays which are designed to be used for protection and control of the distribution network. A close connection is needed to the remote terminal units in the line locations as well (Fig. 83).

Neutral voltage analysis

The method for earth fault detection can be explained by the simplified equivalent circuit for the one-phase earth fault (Fig. 84).

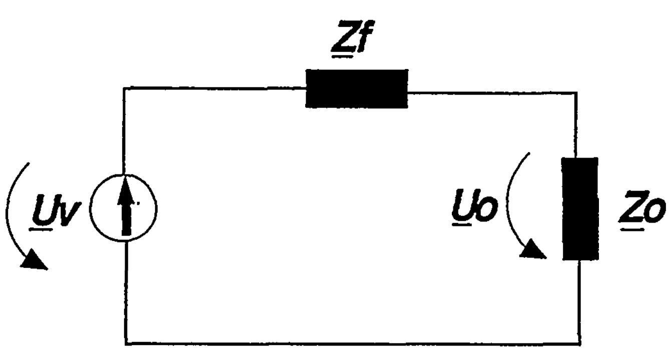

Fig. 84. Simplified equivalent circuit for an earth fault in a distribution network.

Using the equivalent circuit, the fault impedance Z_f can be determined in terms of the measured voltages and the zero-sequence impedance of the network as follows:

$$\underline{Z}_f = (\frac{\underline{U}_v}{\underline{U}_0} - 1) * \underline{Z}_0 \qquad (31)$$

where $\underline{Z}_0$ is the zero-sequence impedance of the network (Fig. 85), $\underline{Z}_f$ is the fault impedance, $\underline{U}_v$ is the positive-sequence component of the phase to earth voltage and $\underline{U}_0$ is neutral voltage. $\underline{Z}_0$ can be determined from the equivalent circuit of Fig.85. In the unearthed network (Fig. 85a) it is the parallel connection of the phase-to-ground capacitances and phase-to-ground resistances, so called "leakage resistance". The total phase-to-ground capacitance 3Ce depends on the "live" length of the feeders of the system. For systems earthed via a Petersen coil it is necessary to take into account also the coil, and the circuit must be complemented with parallel connection of the coil impedance, Fig 85b.

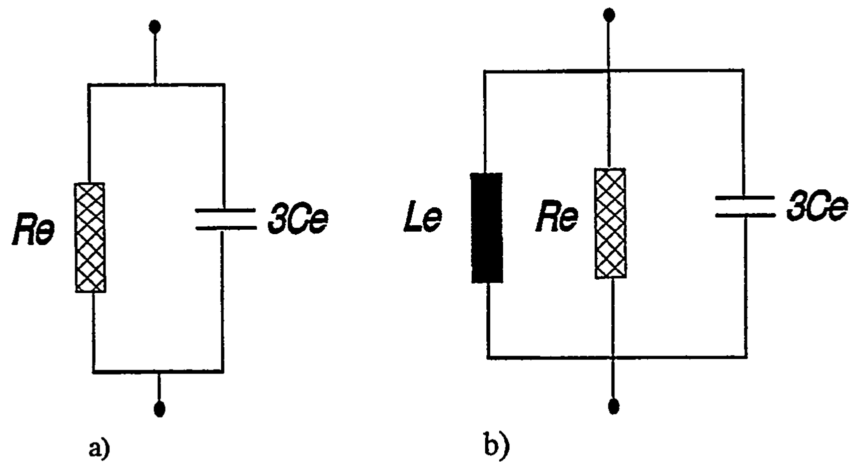

Fig. 85. Equivalent circuit of the zero-sequence network for the unearthed system (a) and for the compensated system (b).

For the detection of the high resistance earth fault it is essential to determine the resistive part of the fault impedance. In Eq.31. U_o represents the phasor sum of the phase voltages and U_v is the positive sequence component of the phase voltage, measured at the moment considered. Applying Eq. 31 three times and using the following values of U_v, the faulted phase can also be determined:

$$\begin{aligned} &1) \quad \underline{U}_V \angle \underline{\varphi} \\ &2) \quad \underline{U}_V \angle \underline{\varphi + 120^\circ} \\ &3) \quad \underline{U}_V \angle \underline{\varphi + 240^\circ} \end{aligned} \qquad (32)$$

From the calculated three values of Z_f, the resistive part shows the highest value in the faulted phase. Because the fault impedance must be resistive, the calculated resistive parts of Z_f for the other two "healthy" phases are negative. The triggering level of the algorithm is set so, that a high resistive earth fault is indicated, if the calculated maximum real part of Z_f is four times the magnitude of the imaginary part of the corresponding Z_f.

The detection of very high fault resistances is difficult due to the neutral voltage present in the normal network conditions. This is mainly caused by the natural unbalances of the feeders. The sensitivity of the method can be improved by using the change of the neutral voltage which is determined as a difference of the real neutral voltage in the network at the moment being considered and of the corresponding mean value of the last ten minutes. After calculation of the fault resistance the residual current can also be determined using the equivalent circuit of Fig. 84. When combining this information to the knowledge about the faulty phase, a very powerful means for detecting the faulty feeder, and further the faulty branch of the line, can be implemented.

19.6 FEASIBILITY OF THE METHOD AND ERROR SOURCES

In order to expose the detection algorithms to a wide range of field conditions, the algorithms were tested with naturally occurring faults, intermittent disturbances, staged faults and normal system activity. The feasibility of the method were also verified by an analysis based on simulated data, which was derived using an EMTP-ATP based network model. In the simulations, the sampling rate was 500 Hz and the sampling period was one second. Using simulated data, earth faults up to 500 kΩ could be detected by the neutral voltage algorithm. In order to evaluate the accuracy of the algorithm, we must keep in mind, that the simulated data did not include error factors. Among these are the noise of the measured quantities produced by the power system itself, the accuracy of the measurement transducers, the properties of the electrical circuits of the measuring system and so on [30].

The field tests with staged faults were carried out in the normal network conditions at the Lammi substation of Häme Electricity and at the Maalahti substation of Vaasa Electricity, where the distribution networks are unearthed and at the Kitee substation in North-Carelian Electricity, where the network is compensated. The networks are mainly of overhead construction. Tables 16...18 show some results of the earth fault test.

Table 16. Experimental results obtained by the neutral voltage algorithm.

Staged fault		Lammi		Maalahti		Kitee	
R_f kΩ	Ph.	R_f kΩ	Angle deg.	R_f kΩ	Angle deg.	R_fkΩ	Angle deg.
20	L1	15.9	8.6	20.5	11.3	17.0	-7.2
40	L2	39.8	7.6	41.7	2.1	26.4	-10.1
60	L3	71.2	1.8	62.2	10.5	46.8	-2.9
80	L2	83.0	7.6	80.5	-1.1	50.2	-10.1
100	L1	111.8	6.9	131.3	5.5	81.5	-14.8
160	L3	179.5	-7.6	120.0	18.7	142.4	-3.0
180	L3	177.0	-33.6	141.6	17.2	156.6	-0.9
220	L3	178.1	-40.6	223.3	27.0	194.4	-2.4
Tree	L1	174.4	9.4	-	-	-	-
Tree	L1	207.1	7.0	-	-	-	-
Tree	L2	281.9	33.3	-	-	-	-
Tree	L3	237.8	-32.0	-	-	-	-

Table 17. Changes of residual currents at the beginning of the feeders at the Kitee substation and at the disconnector location. Faulted feeder is marked in bold.

Staged fault		Substation					Disc.
Rf kΩ	Ph.	Io1 (A)	**Io2 (A)**	Io2 (A)	Io4 (A)	Io5 (A)	Io (A)
20	L1	0.284	**0.467**	0.227	0.599	0.569	**0.106**
40	L3	0.157	**0.421**	0.149	0.384	0.390	**0.076**
60	L2	0.108	**0.284**	0.091	0.248	0.239	**0.047**
80	L3	0.082	**0.152**	0.062	0.175	0.170	**0.033**
100	L2	0.054	**0.105**	0.069	0.182	0.178	**0.030**
120	L3	0.045	**0.069**	0.042	0.109	0.097	**0.018**
160	L1	0.010	**0.093**	0.043	0.137	0.139	**0.030**
180	L2	0.039	**0.036**	0.047	0.134	0.127	**0.028**
200	L1	0.034	**0.063**	0.047	0.125	0.110	**0.014**
220	L1	0.021	**0.049**	0.025	0.057	0.055	**0.023**

Table 18. Some experimental results for detection of the faulted feeder in compensated network obtained by the residual current algorithm. Faulted feeder is marked in bold.

Staged fault		Substation					
Rf kΩ	Ph.	Io1 (A)	**Io2 (A)**	Io2 (A)	Io4 (A)	Io5 (A)	Uo (V)
20	L1	0.047	**0.561**	0.010	0.019	0.017	1350
40	L3	0.053	**0.545**	0.019	0.047	0.056	866
60	L2	0.029	**0.345**	0.056	0.025	0.027	574
80	L3	0.036	**0.191**	0.006	0.015	0.014	422
100	L2	0.015	**0.197**	0.012	0.034	0.032	365
120	L3	0.010	**0.095**	0.007	0.027	0.018	242
160	L1	0.027	**0.157**	0.010	0.026	0.028	201
180	L2	0.035	**0.114**	0.022	0.064	0.061	204
200	L1	0.050	**0.120**	0.026	0.069	0.059	154
220	L1	0.006	**0.072**	0.005	0.003	0.001	130

Table 19. Fault resistances detected by neutral voltage algorithm before the fault developed into a permanent one.

Substation	Fault cause	R_f / kΩ
Honkavaara	Broken insulator	20.0
Honkavaara	Broken insulator	108.0
Honkavaara	Broken insulator	110.0
Honkavaara	Transformer fault	29.8
Honkavaara	Snow burden	29.2
Honkavaara	Snow burden	104.0
Kitee	Downed conductor	228.0
Lammi	Downed conductor	223.0
Renko	Tree contact	95.5

Table 20. Fault resistances detected by neutral voltage algorithm in the case of some intermittent disturbances in the network.

	Unearthed network			Compensated network		
	$R_{f,min}$ kΩ	$R_{f,max}$ kΩ	$R_{f,mean}$ kΩ	$R_{f,min}$ kΩ	$R_{f,max}$ kΩ	$R_{f,mean}$ kΩ
Switching action	43	199	93	10	218	53
Thunder storm	85	116	93	-	-	-
Snowfall	199	268	233	46	318	136

Table 16 shows the fault resistances determined by neutral voltage algorithm from the field measurements at three substations and in Table 19 some corresponding values for the real case faults before they developed into a permanent fault. Especially in the compensated network, residual currents of the feeders are very low in the case of high resistance earth faults. Table 17 shows the measured changes of the residual currents at the beginning of the feeders at the Kitee substation and at the disconnector location. Faulty feeder is marked in bold. In Table 18 some experimental results for detection of the faulty feeder in a compensated network obtained by the residual current algorithm are shown. Our experience has shown that these algorithms are able to detect resistive earth faults up to a resistance of 160 kΩ in a 20 kV distribution system.

The drawback is that the normal system activity and intermittent disturbances cause changes to neutral voltage and residual currents similar to the real faults in the feeders. Table 20 shows the calculated resistances which correspond to the recorded changes of the neutral voltages in the case of normal switching actions, thunderstorm activity and snowfall. These results are based on the continuous monitoring and recording of the neutral voltages at four substations during the period of one and a half year. For discrimination of the intermittent disturbances, the algorithms use one second mean values of the currents and voltages, and for calculations of the corresponding changes, mean values of the last ten minutes are used as a reference level. Snowfall and thunderstorm activity can be identified by the fact, that their effect is seen in several feeder current measurements at the same time. The switching actions, in turn, can be discriminated by the phase angle of the fault impedance computed by the algorithm. In addition, real-time information of the network connectivity changes, obtained from the SCADA and network automation systems, can also be used.

19.7 CONCLUSIONS

A new method was presented for the single phase to earth fault detection and location in high impedance earthed distribution systems. The method is able to detect faults up to 160 kohms. The drawback of the method is that the normal system activity and intermittent disturbances may cause changes to neutral voltage and residual currents similar to the real faults in the feeders. Examples of these cases are normal switching actions, thunderstorm activity and snowfall. This problem can be mitigated by using longer time average measurements for comparison when identifying the faulty feeder or line section and by a proper integration of the automation systems, including protective relays, substation SCADA and network automation.

20 NOVEL METHODS FOR EARTH FAULT MANAGEMENT IN MEDIUM VOLTAGE DISTRIBUTION NETWORKS

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Methods to improve extinction of the earth fault arc in the medium voltage network and to reduce of the short interruptions to customers have been studied on this project. Two other targets were to develop methods for earth fault distance estimation with permanent earth faults and determination of the key parameters of the compensated medium voltage network describing the electric state of the system. The calculation of the phase-to-earth admittance and unbalance of the MV system and separate feeders is a promising method for the identification and location of the high impedance earth faults. All the methods were tested by utilizing simulation results and by field tests in a real distribution network. The ATP-EMTP program (Electromagnetic Transients Program) was applied in the simulations.

The three essential targets of this project are listed in the following.

- An economic principle to improve fault arc extinction without reclosing function is proposed. The novel compensation and protection practice was tested in one rural distribution network. The selective functioning of the earth fault protection based on the active current was ensured by simulations and field tests. The influence of the star point impedance to the number of short interruptions is discussed.

- The determination of the key parameters of a compensated distribution system by utilizing the measured data is introduced. Methods for identification of the high impedance earth faults are also presented.

- The earth fault distance estimation by rearranging of the affected feeder into a closed ring over an adjacent feeder is studied.

20.1 INTRODUCTION

Customers have become less and less tolerable against even short interruptions of supply. Rapid autoreclosures are especially harmful for those commercial and private customers who have equipment which will be disturbed by these under half second interruptions. Mainly due to increasing use of distribution automation (eg. remote controlled switching devices, fault detectors, computational fault location) the average interruption period per customer has been reduced. Simultaneously the amount of equipment sensitive to short voltage break or dip has increased. Therefore reducing the number of the interruptions has become a more essential target.

The improvement of the quality of the electricity distribution is currently a subject of increasing interest. Fast fault identification and location in distribution networks are essential to improve the quality of supply, which is one basic requirement of modern society. Thus an accurate supervision of the distribution systems in order to evaluate the actual state of the network and make the early detection of the earth faults possible becomes more and more important. It is important to detect a highly resistive earth fault and identify a faulted feeder before a fault causes an outage to the customers. The determination of the electric state of the system also supports preventive maintenance strategies.

As a result of this project methods for determining two target parameters of the supervision are presented. These parameters are the total phase-to-earth admittance and the unbalance of the system and each of the feeders of the HV/MV substation. The imaginary part of the total phase-to-earth admittance called susceptance allows an estimation of the electric length of the feeder. The fault current calculation based on the phase-to-earth susceptance values obtained from the manufacturers of the lines or underground cables is in many cases quite inaccurate. Both parameters can be utilized to indicate the fault and identify the faulted feeder with high impedance earth faults. Using two different values of the zero sequence voltage and the corresponding zero sequence currents of the feeders, the other parameters of the compensated system, mismath and damping can also be calculated /32/. The zero sequence voltage of the system can be specified by using three parameters: unbalance, mismatch and damping.

Nowadays the fault distance of short-circuit faults can be calculated very accurately using the measured short-circuit current /12/. Permanent phase-to-earth faults are still problematic in compensated and isolated networks. The computational earth fault distance estimaton is a difficult task in isolated or compensated distribution systems because the impedance of the radial MV line between the substation and fault location has no significant effect on the fault current. Thus the earth faults call for new methods to be located. At present the fault location is determined by dividing the faulted feeder into sections by a disconnector and closing the substation circuit breaker against the fault until the faulty line section is found. This is time consuming, since the operation of disconnectors requires a patrol moving in the terrain. The use of the methods developed for calculating the distance to an earth fault in a compensated MV distribution network considerably reduces the time needed for fault location. The methods were tested by utilizing simulation results (EMTP) and by field tests in a real distribution network. The fault location methods presented usually require a compensation of the earth fault current because the location takes some time and the safety regulations for the hazard voltages must be fulfilled. The compensation makes it possible to locate the fault without outages to the customers.

20.2 DISADVANTAGE OF RAPID AUTORECLOSING FUNCTIONS TO CUSTOMERS

Economic evaluation of short interruptions concerning autoreclosures used to clear temporary faults in overhead line networks is difficult. Usually an evaluation of the disadvantage requires a detailed study of certain customers and cases. Furthermore, the disadvantage may vary greatly depending on the day and season, for instance.

An attempt to determine the disadvantages of short interruptions was made by relatively brief questionnaire studies directed at residential and agricultural customers of two rural utilities Rovakaira Oy and Kainuun Sähkö Oy. In Rovakaira the questionnaires was sent by mail to customers. In Kainuun Sähkö customers were interviewed in their homes and the questionnaires were filled in together with a customer. Most of the customers (66 %) interviewed in Rovakaira remembered 2 - 5 short interruptions during the last year. In Kainuun Sähkö only 40 % of customers remembered 2 - 5 and 50 % many short interruptions. If in some feeder a dozen rapid autoreclosures happened during the last year over one third of the customers had noticed a large number of interruptions. None of the customers interviewed reported more interruptions than had actually happened. Usually customers remembered fewer short interruptions than they had in reality experienced. The number of rapid autoreclosing operations is distributed unevenly during different seasons. A major part of the autoreclosures occurs in summer during a thunderstrom period and in early autumn during the migration of birds.

Over 60 % of households consider short outages just a little harmful. The more a customer has noticed short interruptions the more harmful he considers them. If a customer has not noticed short outages at all he considers them mainly harmless. About 80 % of households are ready to accept 2 - 5 short interruptions per year. If a customer has experienced many interruptions during the last year, the willingness to accept short outages falls considerably.

Reducing of the number of short interruptions caused by temporary earth faults requires investments. Therefore one part of the questionnaire surveyed the willingness of the customers to pay for an avoidance of the outage and the disadvantage caused by it.

20.3 NEUTRAL TREATMENT OF MEDIUM VOLTAGE SYSTEMS

The single phase-to-earth fault is the most common fault type in medium voltage networks. In rural conditions distribution transformers are small and horn gaps are widely used for the overvoltage protection. Most of the earth faults cause an arc at its location. The treatment of the neutral, in the medium voltage system, has a major influence on the system behavior during an earth fault /34/. Extinction of an earth fault depends on the behavior of the recovery voltage and the magnitude of the residual fault current.

Circuit breakers especially in overhead line networks are equipped with rapid and delayed autoreclosing devices. The neutral earthing policy has a considerable effect on the disappearance of the earth fault arcs and therefore it directly affects the number of short interruptions to customers.

20.3.1 A novel compensation and protection practice

The compensation of the earth fault current can be carried out by means of several small compensating units located at different points in the network (decentralized compensation). This cost effective practice is applied in some rural utilities in Finland. The main reason for this practise has been the need to reduce hazard voltages with earth faults without expensive improvement of protective earthings.

The essential target of this study was to introduce a new economic principle to improve fault arc extinction without reclosing function in isolated or partially compensated networks. The compensation degree can be raised to the same level as with traditional centralized resonant earthing (equipped with control automation) in the primary substation. A principle to determine the relay settings and ensure the selective functioning of directional relays by utilizing the ATP-EMTP model is also studied.

We have studied the potential of considerably increased compensation degree because this has an essentially positive effect on the extinction of the arc and reduces considerably the number of short interruptions to customers. The present decentralized compensation practice with about 50 % compensation degree does not have this positive effect. A considerable part of the compensation capacity can be located in the primary substation. It is practical to place a minor part of the compensation capacity at the end of longest feeders so that a roughly self-adjusting system could be achieved. The characteristics of the directional earth-fault relays must then be changed because the protection can no longer be based on the reactive current measurement. The selectivity may be based on the measurement of the active current component. Nowadays inexpensive 20 A compensation units are available. The inductance of the coil can be adjusted in 2.5 A steps between 15 A and 25 A. The unit includes both a suppression coil and an earthing transformer with YNd-connected windings. The control of the coil can be done step by step via the remote control system.

This kind of combination of fixed centralized and decentralized compensation was tested in summer 1996 at one rural 110/20 kV substation. A 16 MVA substation transformer feeds six overhead line feeders. The combined line length of the network is 573 km, so that the MV feeders are very long (72 - 133 km). Before the experiment four (5/3.5 A) compensation units were connected in the network, two (2x5 A) at the substation and two (2x3.5 A) at the end of MV feeders. In the new compensation experiment two 5 A units at the substation were replaced by one new 20 A compensation unit which was adjusted to a 25 A position. The network and location of the compensation units are illustrated in Figure 86.

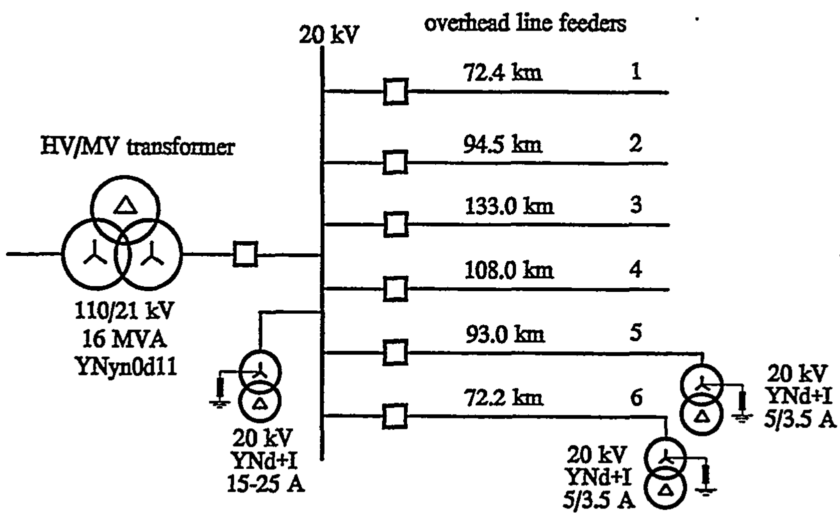

Fig. 86. MV network used in the compensation experiment.

20.3.2 New relay settings

Modern numerical earth fault relays with Icosφ measurement at the substation are used. New active current measurement based relay settings were calculated by utilizing the ATP-EMTP program. The dynamic model for the whole network (Figure 86) was developed by using ATP-models for the the overhead lines, primary transformer, circuit breakers and star point components. By utilizing TACS (Transient Analysis of Control Systems) functions ("devices") the instantaneous value curves of the zero sequence voltage and zero sequence currents of the feeders were converted to square waves whose amplitude is one. They can thus be synchronized and it is possible to determine the phase shift of the zero sequence voltage and the current of the appropriate feeder. As a simulation result we also obtain the instantaneous and RMS-values of the zero sequence voltage, phase voltages, zero sequence currents and phase currents of the feeders, earth fault current and star point currents of the compensation units.

The major task is to take care of the adequacy of the active current component which ensures the selective functioning of the protection. Sometimes the magnitude of this component is very small and must be increased by means of an additional star point resistance. This resistance may be located either centrally in the secondary star point of the substation transformer or in the compensation units.

The selective functioning of the relay protection was checked in advance by an ATP model of the network. An earth fault with fault resistance was caused in every feeder in turn. The zero sequence currents of the faulted and healthy feeders, zero sequence voltage and phase angle between them were obtained as a simulation results. According to calculations and field experiments the resistive component of the fault current produced by the compensation units (previously mentioned 20 A and 3.5/5 A units) and overhead line network itself is usually adequate for the directional earth-fault relays.

20.3.3 Results of field experiments

In the beginning of every six feeders a single phase-to-earth fault was caused in sequence. All tests were made with three values of the fault resistance 0 ohm, 500 ohm and 1000 ohm. The zero sequence voltage and the zero sequence currents of the feeders were measured and synchronized with each other. With every fault resistance the earth fault protection tripped the faulted feeder selectively and no malfunction of the protection was observed. The new 20 A compensation unit is connected to substation busbar via a remote-controlled disconnector. The position message of the disconnector is transferred to the numerical relays. Thus the characteristics of the directional relays change automatically if the disconnector is controlled. When the disconnector is closed and the compensation unit is connected to the network the earth fault relays function with Icosφ measurement. When the disconnector is opened the characteristics change to Isinφ measurement. Thus we can also ensure the functioning of the protection with exceptional connection arrangements and prevent a considerable overcompensation of the network. This kind of compensation system has been in use since the end of July 1996 at one 110/20 kV substation.

20.3.4 Benefits

The main benefits of this previously described protection and compensation practice are

- low earthing and hazard voltages
- savings in earthing costs
- low rising speed and amplitude of the recovery voltage (improves the self extinction of the arc)
- low fault current (improves self extinction of the arc)
- lower fault current makes it possible to increase the tripping delay of the earth fault protection (more time for self extinction of the arc)
- selective earth fault protection for any network connection
- overcompensation of the network or feeders does not lead to malfunctions of protection
- significantly lower investment costs than in centralized compensation equipped with automatic resonance control of the coil (but equally good conditions for self extinction of the arc)

20.4 FEASIBILITY OF UTILIZING SHUNT CIRCUIT-BREAKERS IN FINNISH MV NETWORKS

One possibility for extinguishing of an earth fault arc in MV network is by using a shunt circuit-breaker to earth the faulted phase at the feeding substation in the case of earth fault (Figure 87). The original fault is then short-circuited. This phase earthing method can be used to extinguish arc-type earth faults or to reduce the hazard voltage of the fault location in permanent faults without causing a break in the power supply.

An earth fault in a MV system with an isolated or resonant earthed neutral has been surveyed based on literature. Requirements of the safety regulations for earth fault protection have been reviewed. The coming CENELEC (European Committee for Electrotechnical Standardization) regulations have been dealt with based on the most recent standard draft (1996) /38/.

The basic functioning of the phase earthing system has been presented. Special attention is paid to the realization of the relaying and to the necessary conditions for arc extinction to take place.

20.4.1 Modelling of phase earthing system

An equation for the residual current of the fault location has been derived with the aid of symmetrical components. The effect of load and the effect the method of system earthing on the residual current has been taken into account, Eq. (33) /31/. The connection of the sequence networks is illustrated in Figure 88. The earth potential rise at the fault location has been evaluated and the connection between it and the voltage drop of a line has been presented. The residual current in fault location is:

$$\underline{I}_e = \frac{3\underline{U}_v\,(R_L 3R_s - \underline{Z}_{mc}\underline{Z}_1)}{2\underline{Z}_1 R_L(3R_s+\underline{Z}_{mc}) + 3R_s\underline{Z}_{mc}(\underline{Z}_1+R_L) + (\underline{Z}_1+R_L)(3R_s+\underline{Z}_{mc})(\underline{Z}_0+3R_f)} \tag{33}$$

where

$\underline{U}_v$	phase-to-earth voltage
R_L	loading resistance
R_S	earthing resistance of shunt circuit-breaker
R_f	fault resistance
C_0	phase to earth capacitance
$\underline{Z}_m$	star point impedance
$\underline{Z}_{mc}$	impedance of parallel connection of $3\underline{Z}_m$ and C_0
$\underline{Z}_1$	positive sequence impedance of the line
$\underline{Z}_0$	zero sequence impedance of the line

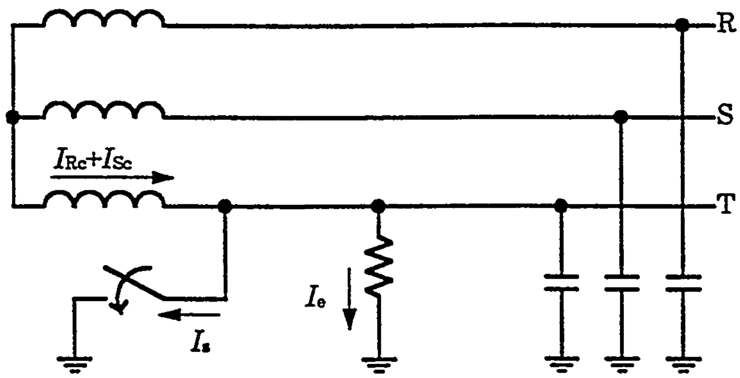

Fig. 87. Principle scheme of phase earthing system. $I_e = I_{Rc} + I_{Sc} - I_s$.

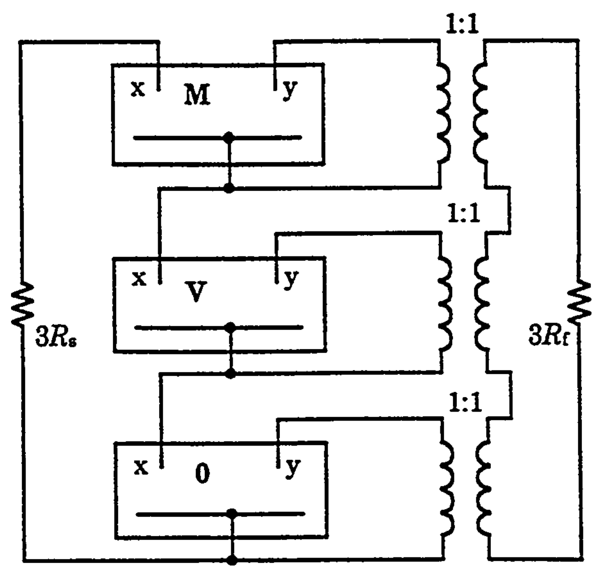

Fig. 88. Combination of sequence networks with phase earthing system. x is the location of shunt circuit-breaker and y is the location of the fault.

20.4.2 Applicability in Finnish MV networks

Finally, the possible ways of using this method in Finland have been considered. Especially in isolated MV networks the limit for the residual current self extinction of the arc is so low that the earth fault arc cannot usually be extinguished without an autoreclosing function.

The functioning of the shunt circuit-breaker does not cause a voltage break to low voltage customers. One disadvantage of the phase earthing system is that the extinction of the arc also depends on the load condition of the feeder. The influence of the load current can be reduced by a resistor connected series with the shunt circuit-breaker. The use of this series resistor is advantageous especially in heavy load conditions.

Both domestic and foreign experiences of the earlier use of the phase earthing system have been gathered. At present the system is widely used in France and Ireland. It has been used both in isolated and via resistance earthed systems. According to these experiences about 50 - 75 % of single phase to earth faults have been cleared by this system. The phase earthing system is also used with permanent faults to make continuation of the power supply possible during the fault.

In this study a method was presented to determine the maximum earthing voltage in a fault location based on a voltage drop of the line. The fault resistance has a significant effect on the earthing voltage. With low values of fault resistances the earthing voltage is a fraction of a voltage drop of a line.

The use of the phase earthing system to clear temporary earth faults and to reduce short interruptions to customers in Finnish MV overhead line networks is possible. Compared to the centralized compensation of the earth fault current, the cost of the shunt circuit-breaker equipment is modest.

The utilization is limited mainly by recent Finnish safety regulations. The system is the least suitable for networks where very short tripping times of the earth fault protection must be used or where the earth fault current will be greatly increased for example in a consequence of increasing underground cabling in the future. It is not possible to use the method to maintain the supply to customers during permanent faults until a reliable method to check the fault potential rise has been developed.

20.5 METHODS FOR EARTH FAULT IDENTIFICATION IN A COMPENSATED MEDIUM VOLTAGE DISTRIBUTION NETWORK

The target of the study was to clarify out the method of determining the total phase-to-earth admittance and the unbalance of each feeder of a HV/MV substation. The method is based on the measurement of the zero sequence currents of each feeder with two different values of the zero sequence voltages. In the case of a compensated power distribution system, the necessary variation of the neutral point to earth voltage can be obtained by modifying the star point impedance of the system or the galvanic length of the network (i.e. adding or switching off one or several feeders). We consider a HV/MV substation with 1 - i separate feeders whose simplified equivalent circuit is presented in Figure 89.

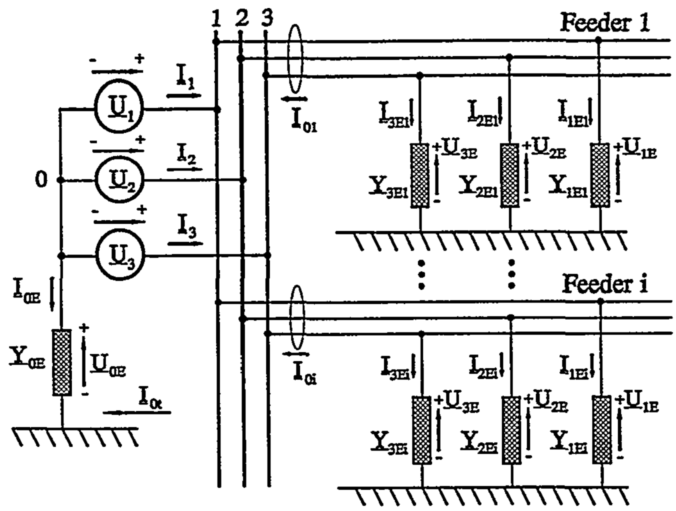

Fig. 89. Simplified equivalent circuit for a compensated network.

The capacitive part of the total phase-to-earth admittance of the feeder allows an estimation of its "live" length. The resistive part can be used to detect highly resistive earth faults, taking into account climatic conditions and comparisons with other feeders. The determination of the phase-to-earth admittance of the whole system makes it possible to calculate the earth fault current much more accurately than by using rough tabular values of the phase-to-earth susceptances from the network data base. The change in the unbalance of the feeder is a sensitive indicator with highly resistive earth faults.

Only the steady state of the system at its rated frequency will be considered. The longitudinal reactances of the lines and voltage source are omitted. The three-phase voltage source is supposed to be ideal, balanced, sinusoidal and without internal impedance. The zero sequence currents and zero sequence voltage are independent of loads. The methods presented afterwards assume that the zero sequence currents and the neutral to earth voltage are available as complex values, so the magnitude and the phase angle of their fundamental signal must be calculated from the measured signals.

According to Figure 89 the complex single phase-to-earth admittances comprise the total phase-to-earth admittances of all feeders. The complex neutral-to-earth admittance forms as a parallel connection of the neutral-to-earth inductance L_{0E} and resistance R_{0E}. The total phase-to-earth admittance which is defined by a sum of the three phases can be determined for the whole system or one separate feeder. The notations used for subscripts of the admittances, resistance, capacitance and unbalances have the following structure:

i = number of the feeder, i = 1,2,3,...
t = total sum of the three phases
0 = neutral point
E = to earth

The phase-to-earth admittance will be normally capacitive with a small resistive part due to line losses. ω is fundamental angular frequency of the system ($\omega = 2\pi f$).

$$Y_{tE} = \frac{1}{R_{tE}} + j\,\omega\, C_{tE} \tag{34}$$

The theory of compensated power systems defines the unbalance of the system $\underline{k}$ as follows /32/:

$$\underline{k} = \frac{\underline{Y}_{1E} + \underline{a}^2\ \underline{Y}_{2E} + \underline{a}\ \underline{Y}_{3E}}{j\,\omega C_{tE}} \tag{35}$$

$\underline{a}$ and $\underline{a}^2$ are phase rotation operators ($2\pi/3$ and $4\pi/3$, respectively). The unbalance $\underline{k}$ is a normalized complex parameter indicating the phase and the magnitude of the asymmetry of the three phases to earth. Its value depends on the topology and the nature of the system (overhead lines, underground cables). The typical value of $\underline{k}$ is between 0.001 and 0.03 /32/. In the analogy of the definition of the unbalance of the whole system, it is possible to define the unbalance of each feeder using the corresponding admittance and capacitance values of the individual feeder.

Some possible applications of the described method are:

- estimation of the galvanic length of the feeder using the information about its total phase to earth capacitance (more accurate calculation of fault current and hazard voltages)
- detection of resistive earth faults
- estimation of the values of the key parameters describing the state of the distribution system: unbalance, mismatch, damping

20.6 ESTIMATION OF THE DISTANCE TO EARTH FAULT

Distribution networks are normally operated radially. The information on the earth fault distance can be obtained by rearranging the faulted feeder into a closed ring over some healthy feeder. The ring connections must be planned in advance and are connected mainly by a remote-controlled disconnector.

20.6.1 Steps of the location process

Different steps of fault location process in the case of permanent earth fault are presented below.

$\underline{U}_0$ = zero sequence voltage of the system
$\underline{U}_{12}$ = phase-to-phase voltage
$\underline{I}_{01}$ = zero sequence current of Feeder 1
$\underline{I}_{02}$ = zero sequence current of Feeder 2

1. Detection and directional information of the fault (numerical relays)

2. Calculation of the fault resistance and checking of the safety regulations: precondition for fault location

3. Ring connection by remote-controlled disconnector

4. Measurements: $\underline{U}_0$, $\underline{U}_{12}$, $\underline{I}_{01}$, $\underline{I}_{02}$

5. Signal processing: instantaneous values of the signals to complex values of the fundamental frequency signals, phase referencing of the signals to $\underline{U}_{12}$ or $\underline{U}_0$ (depends on the location method)

6. Calculation of the fault location and disconnection of the faulted section

The algorithms presented assume that the zero sequence currents and the zero sequence voltage are available as complex values, so the magnitude and the phase angle of their fundamental signal must be calculated from the measured signals. This sets some requirements on practical measurement equipment (i.e. disturbance recorder type of data is needed).

In the following, three different methods for the earth fault location are presented. The feeders arranged into a closed ring are fed from the same substation. The distribution of the zero sequence currents between the ring connected feeders also depends on positive, negative and zero sequence impedances of the lines. In this study they have not been taken into account. The circle composed of two feeders is purely overhead line feeders with normal loading conditions.

20.6.2 Change of the phase-to-earth admittances of the feeders

One possibility for the estimation of the earth fault distance is to use two different values of the neutral-to-earth voltage and corresponding zero sequence currents of the feeders to determine the phase-to-earth admittances between the fault location and the substation along both feeders (Section 4 in fault location process). A change in the tuning of the compensation coil produces a change in the phase-to-earth admittances on both feeders. The distribution of the total change is directly proportional to the distance to the fault via each feeder.

20.6.3 Reactive components of the zero sequence currents

In isolated or compensated networks, the resistive component of the earth fault current may be very small and inadequate for fault location purposes. Thus the reactive components of the ring connected feeders can be used in fault location. In isolated overhead line networks with high earth fault current, the safety regulations may limit the use of this method.

An algorithm for the calculation of the fault location along both ring connected feeders based on reactive components of the zero sequence currents has been derived. The method supposes that the phase-to-earth capacitance of the line per kilometre is constant. In the case of pure overhead line feeders, this is an acceptable assumption.

The measured information on the sum currents of the ring connected feeders and the zero sequence voltage is needed. The sum currents of the feeders can be measured at the substation by cable-type current transformers. The direction of the zero sequence currents can be from the substation to the feeder or vice versa. The zero sequence voltage is also available as a measuring result.

The phase-to-earth susceptances of the branches connected to the main circle line and length of the main circle are also needed. They can be calculated by using the information of the network database. As a result of the key parameter calculation, a good approximation of the phase-to-earth susceptance of the lines can be achieved.

The algorithm was tested by utilizing the dynamic ATP-EMTP model of the MV network. It was developed by using ATP models for overhead lines, substation transformer, circuit breakers and neutral point components. The fault locations calculated by the developed algorithm using the simulation results gave correct results in compensated and isolated networks. If the feeders arranged into a closed ring consist of different types of lines (e.g. overhead lines and underground cables), the irregular distribution of the phase-to-earth susceptances must be taken into account. The method was also tested using measuring results of field tests which were done in overhead line network.

20.6.4 Resistive components of the zero sequence currents

By measuring the resistive components of the zero sequence currents on the ring connected feeders, the earth fault distance can be estimated based on the distribution ratio of the resistive zero sequence currents. In some cases, the resistive component of the fault current may be inadequate for the fault location. The evaluation of the zero sequence impedances of the lines must be taken account in many cases.

20.6.5 Practical experiences of the field tests

The calculation of the phase-to-earth admittances and unbalances was tested at one HV/MV substation. The necessary variation of the zero sequence voltage was obtained by changing the tuning of the compensation coil. The phase-to-earth admittances and unbalances of the feeders could be reliably determined. As a result of field experiments the real high impedance fault could be detected. About one month after our experiments, when the network was kept under phase-to-earth fault for one hour, the latent high impedance phase-to-earth fault in the cable terminal box led to the development of the cross-country fault.

The estimation of the earth fault distance was tested by connecting the faulted feeder to a closed ring with one healthy feeder. Two experiments were made, one in Rovakaira Oy and the other in Lounais-Suomen Sähkö Oy. In one network the ring consisted of overhead lines and in the other the ring consisted of both overhead lines and underground cables. The experiments were made during normal loading conditions. The fault resistance was varied between 50 ohm 10 kohm. The best results could be achieved with long overhead line ring (123 km). In this case errors were between 1 % and 6.5 % per total length of the circle.

20.6.6 Conclusions

The existence of the fault and the faulted feeder with a high resistance earth fault can be identified by the method described in this section. After the fault indication, the fault location can be determined by connecting the faulted feeder into a closed ring with some healthy feeder usually by a remote controlled switching device. In a compensated network this can be done without outage to customers.

The Power Engineering Group of Tampere University of Technology has developed computer applications for distribution network operation in the past few years /51/. The advanced distribution management system (DMS) called OPERA has been developed for supporting distribution network operation. The DMS is an ideal environment for developing the functions for earth fault location and supervision of the state of the system in practice. Earth fault location and the calculation of parameters describing the electric state of the network will be future functions of the DMS.

When operating as a part of the DMS the network data can also be utilized for fault location. The information obtained from real faults can used to improve the accuracy of the fault location. Using the methods of this study, the time needed for fault indication and location can be essentially reduced. By measuring the phase-to-earth admittances of the feeders and the whole network the fault currents with earth faults can be determined much more accurately than using the tabular values of the lines.

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APPENDIX 1: RESULTS OF THE COST / BENEFIT COMPUTATIONS FOR FINNISH UTILITIES

In this appendix, the results of the cost/benefit computations for some Finnish utilities are given. There are six cases, four representing rural overhead systems and two urban distribution networks of underground construction. The results are given as present values for a high voltage / medium voltage substation feeder. The functions considered are:

1. Line switch remote control
2. Fault indicators at line switches
3. Fault indicator stations
4. Computational fault location
5. Fault indicator remote reading at secondary substations
6. High resistance fault indication
7. Reactive power compensation at MV line locations
8. Voltage regulation
9. Direct load control
10. Load estimation / component load monitoring
11. Switching planning
12. Remote metering / dynamic tariff application

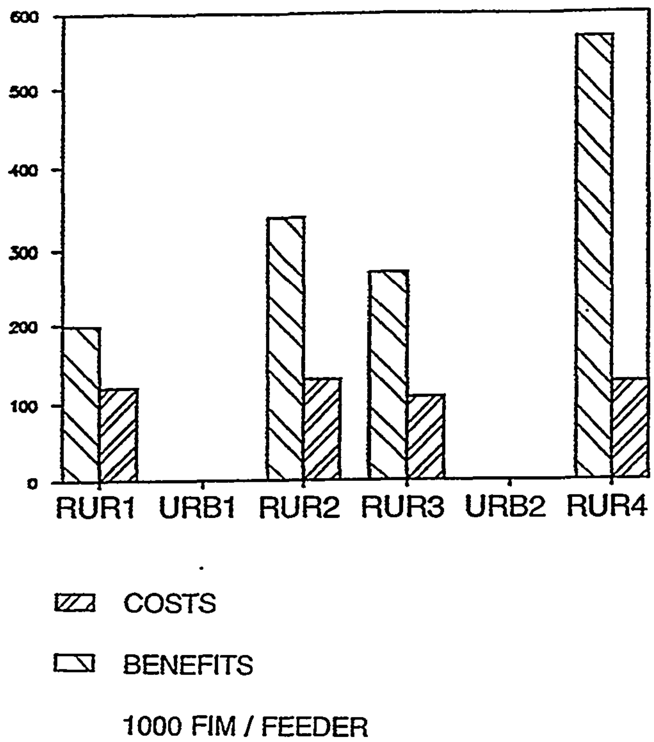


Fig. 1. Line switch remote control.

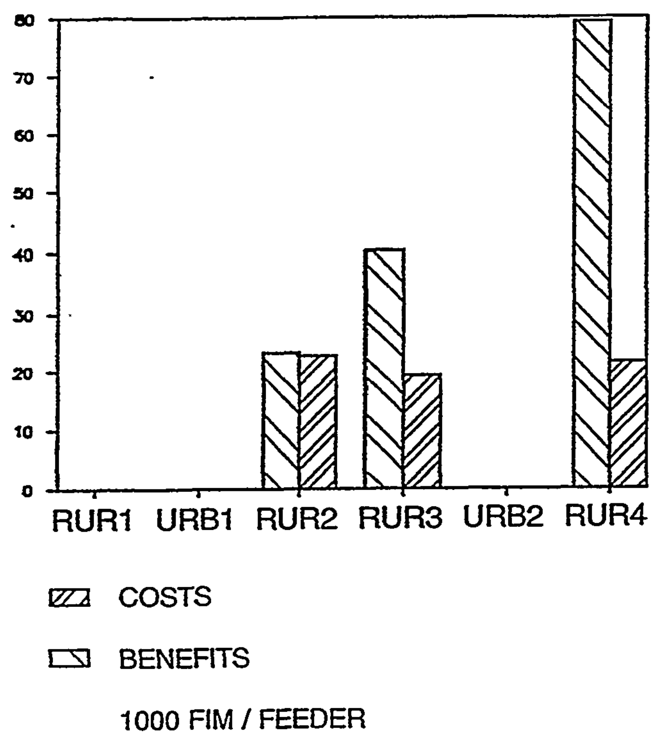


Fig. 2. Fault indicators at line switches.

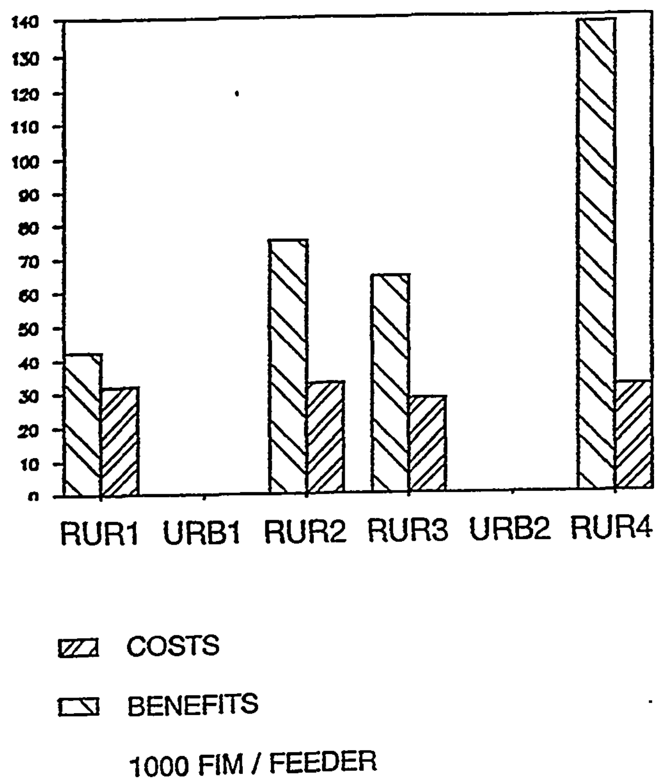


Fig. 3. Fault indicator stations.

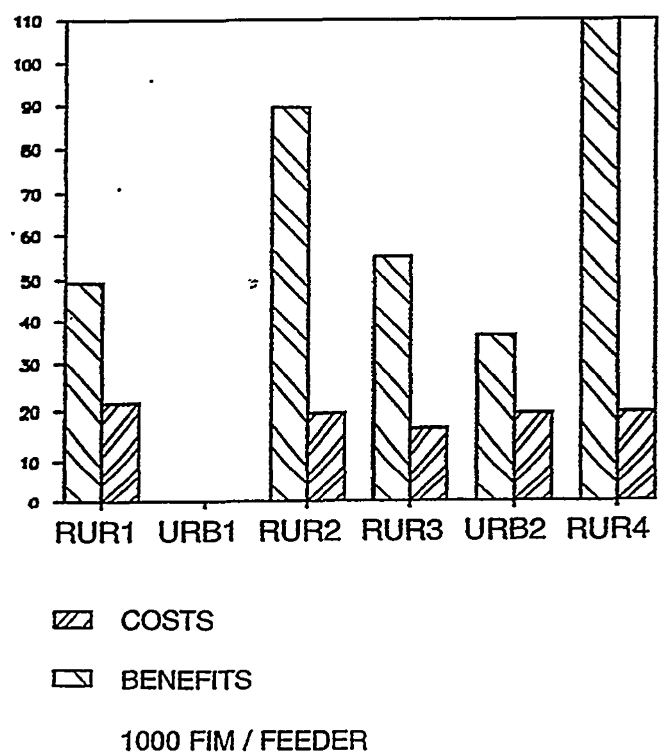


Fig. 4. Computational fault location.

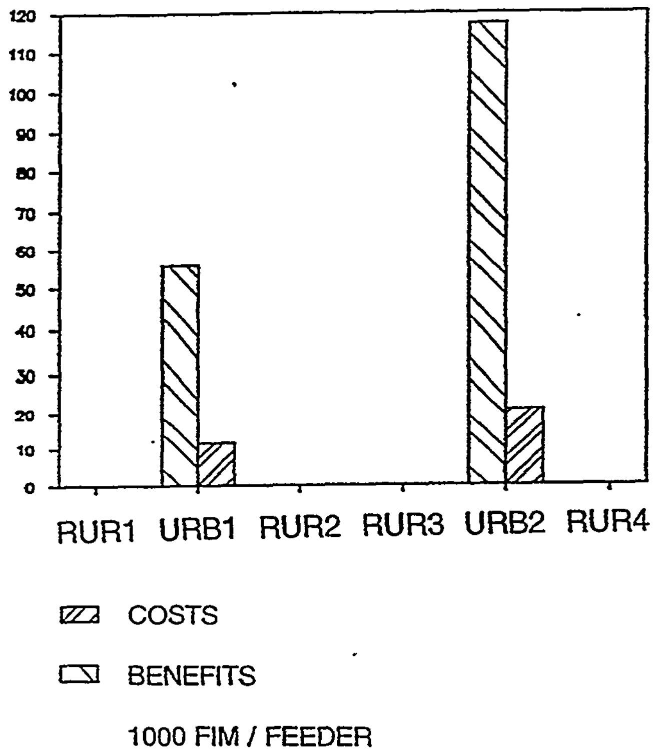


Fig. 5. Fault indicator remote reading at secondary substations.

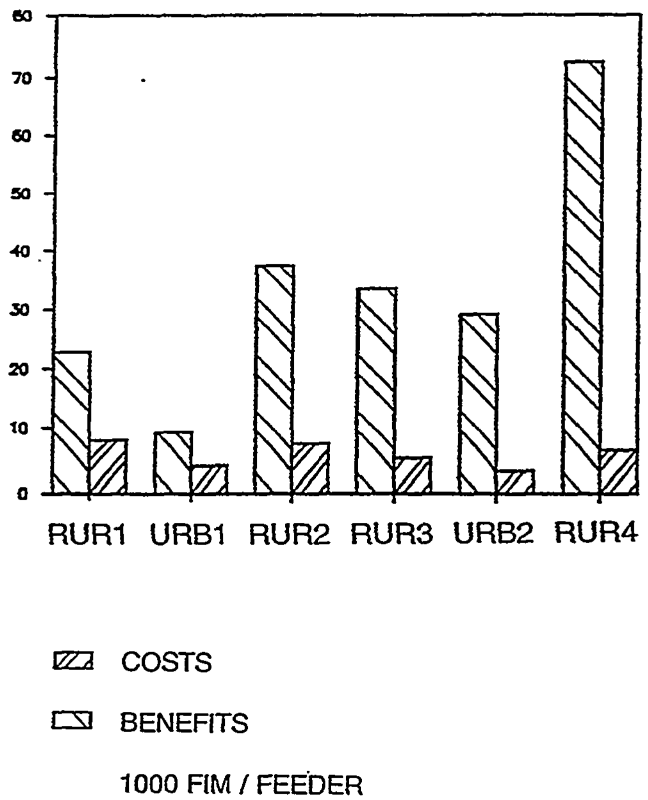


Fig. 6. High resistance fault indication.

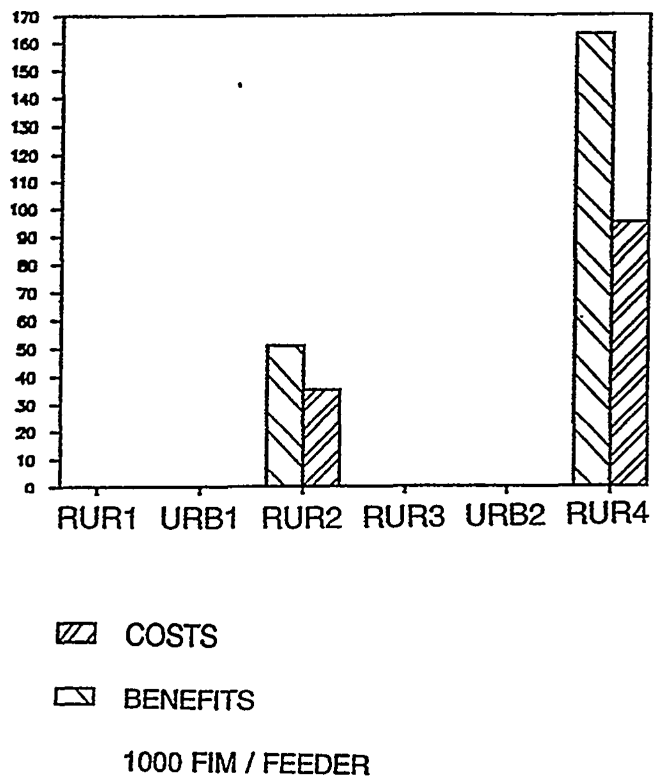


Fig. 7. Reactive power compensation at MV line locations.

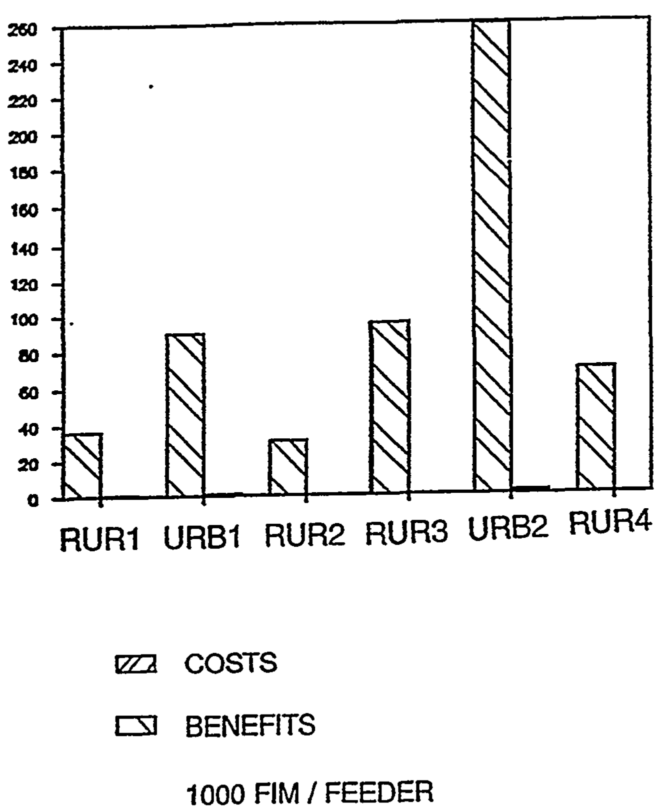


Fig. 8. Voltage regulation.

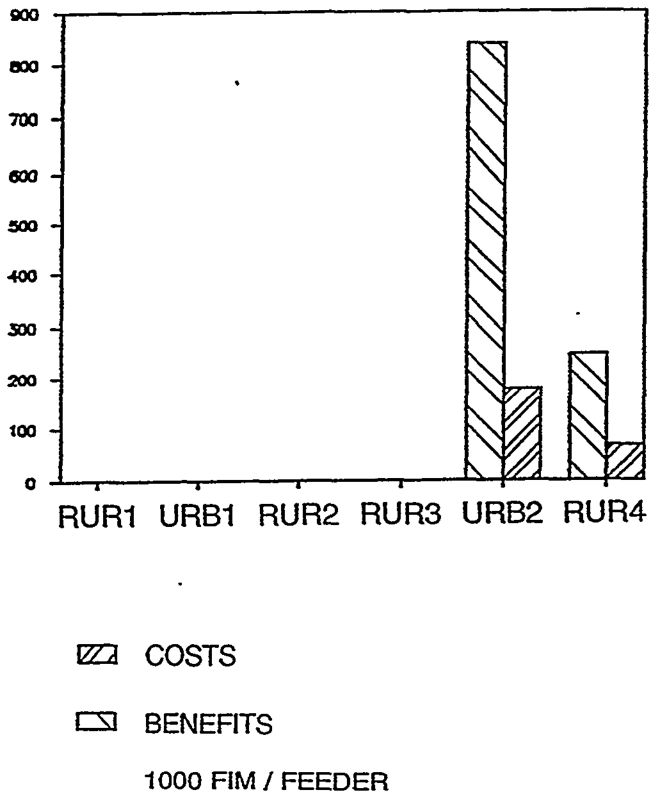


Fig. 9. Direct load control.

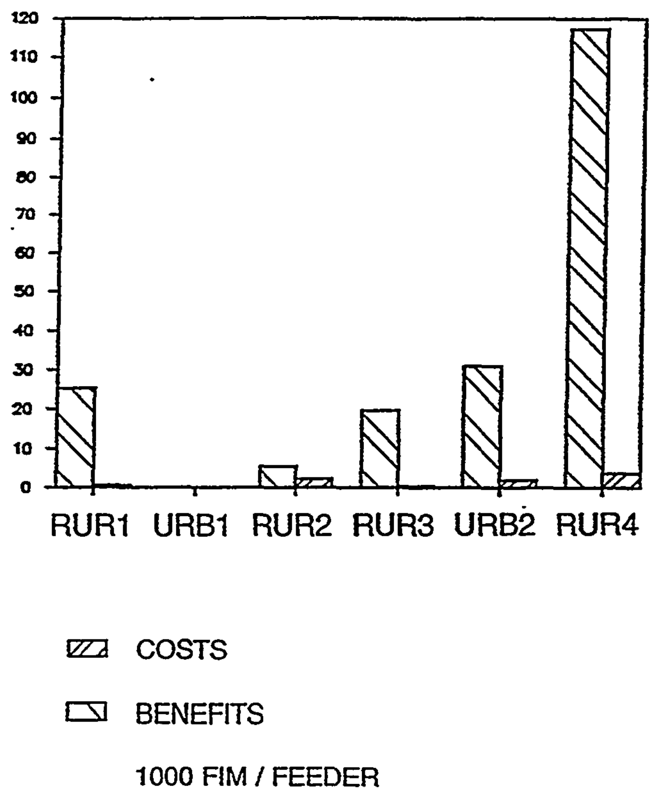
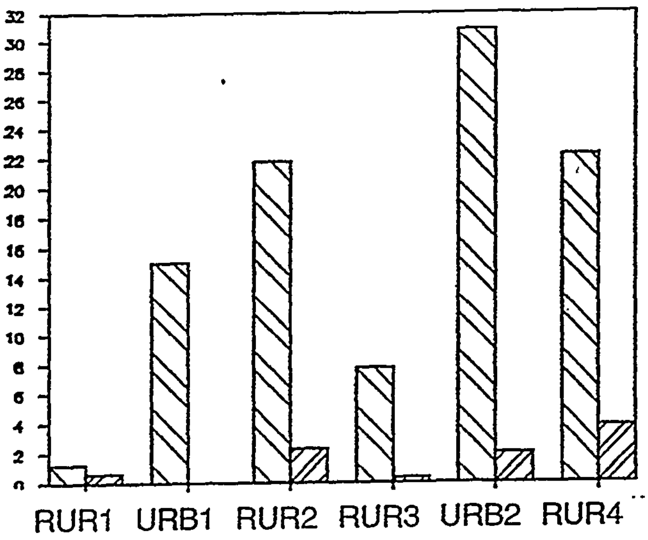


Fig. 10. Load estimation / component load monitoring.

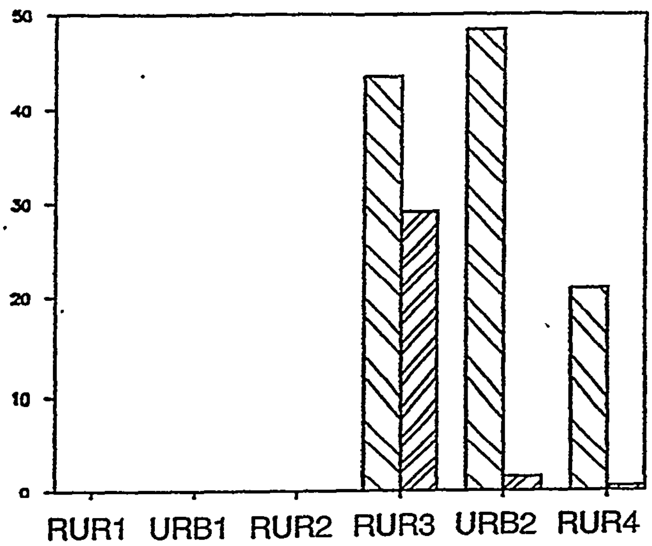


COSTS

BENEFITS

1000 FIM / FEEDER

Fig. 11. Switching planning.



COSTS

BENEFITS

1000 FIM / FEEDER

Fig. 12. Remote metering / dynamic tariff application.

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Final report 1997

Abstract

This report comprises a summary of the results of the five year research programme EDISON on distribution automation in Finnish utilities. The research programme (1993 - 1997) was conducted under the leadership of VTT Energy, in cooperation with universities, distribution companies and the manufacturing industry. The main part of the funding has been from the Technology Development Centre TEKES and from manufacturing companies.

The goal of the research programme was to develop a new scheme for a complete distribution automation system, including the network automation, computer systems in the control centre and the customer associated automation functions. In addition, the techniques for demand side management were developed and integrated into the automation scheme.

The final aim was to demonstrate the automation functions and systems of the scheme in real distribution systems. The results of nineteen projects are given in this report.

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