VTT RESEARCH NOTES 1735 EDISON – research programme on electricity distribution automation 1993–1997. Interim report 1995

RESEARCH PROGRAMME ON ELECTRIC
DISTRIBUTION AUTOMATION

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TECHNICAL RESEARCH CENTRE OF FINLAND
ESPOO 1996

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RESEARCH PROGRAMME ON ELECTRIC DISTRIBUTION AUTOMATION
VTT Tiedotteita – Meddelanden – Research Notes 1735

EDISON – research programme on electricity distribution automation 1993–1997

Interim report 1995

Edited by
Matti Lehtonen
VTT Energy

TECHNICAL RESEARCH CENTRE OF FINLAND
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FINNISH ENERGY TECHNOLOGY PROGRAMMES

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ABSTRACT

The report comprises a summary of the results of the first three years of the research programme EDISON on distribution automation in Finnish utilities. The five year research programme (1993-1997) is conducted under the leadership of VTT Energy, in cooperation with universities, distribution companies and the manufacturing industry. The main part of the funding is from the Ministry of Trade and Industry and from manufacturing companies.

The goal of the research programme is 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 are developed and integrated into the automation scheme.

The final aim is to demonstrate the automation functions and systems of the scheme in real distribution systems. The results of thirteen projects are now given. These results should be considered intermediate, since most projects will be continued in 1996.

LIST OF PROJECTS PRESENTED IN THE REPORT

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

- Automatic location of short circuit faults. Matti Lehtonen, VTT Energy, Tapio Hakola and Erkki Antila, ABB Transmit Oy, Matti Seppänen, North-Carelian Power Company.

- Recording real case data on earth faults in distribution lines. 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, Matti Kärenlampi and Harri Paulasaari, Tampere University of Technology, Jarmo Partanen, Lappeenranta University of Technology.

- Additional functions of remotely read kWh-meters. Pekka Koponen, VTT Energy. Pekka Koponen, VTT Energy, Seppo Vehviläinen, Mittrix Oy and Juha Rantanen, Helsinki Energy Board.

- 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 (DSM). Seppo Kärkkäinen, Veikko Kekkonen, VTT Energy, Pekka Rissanen, Tietosavo Oy.

- Communication technologies for DSM & EurUCA, european utility communication architecture. Pentti Uuspää, VTT Energy.

LIST OF RESEARCH PROJECTS IN 1996

- Development of automatic fault isolation and supply restoration. Matti Lehtonen, VTT Energy.
- Indication of earth faults with high fault resistances. Seppo Hänninen, VTT Energy
- Recording real case data on earth faults in distribution lines. 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.
- A distribution management system. Jarmo Partanen, Lappeenrante University of Technology.
- Event analysis at the HV/MV substation. Jarmo Partanen, Lappeenranta University of Technology.
- Wireless communication technologies in distribution automation. Juha Takala, VTT Energy.
- Communication technologies for demand side management. Pentti Uuspää, VTT Energy.
- EurUCA, european utility communication architecture. Pentti Uuspää, VTT Energy.
- Optimization of load control in the environment of free power market. Pekka Koponen, VTT Energy.
- Distribution automation and demand side management planning methods. Seppo Kärkkäinen, VTT Energy.
- An energy management system for power distribution companies. Anssi Seppälä, VTT Energy.
- Development of marketing and electricity trade practices in the environment of free power market. Martti Muroma and Erkki Laitinen, University of Vaasa.

FOREWORD

This report comprises a short summary of the main results of the research programme EDISON during its three first years 1993, 1994 and 1995. Altogether thirteen 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:

Mr. Otso Kuusisto, The Finnish Association of Electric Utilities
Prof. Erkki Lakervi, Tampere 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
February 1996

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. The goal of the five year programme is 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 will be implemented using the latest data transmission and data processing technology. The aim is 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 will be developed. The work proceeds step by step in cooperation with universities, the manufacturing industry and power companies. The practical work comprises:

- 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 the first two years.

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 /11/.

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 /21/.

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 /16/:

- 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 /14/. 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.

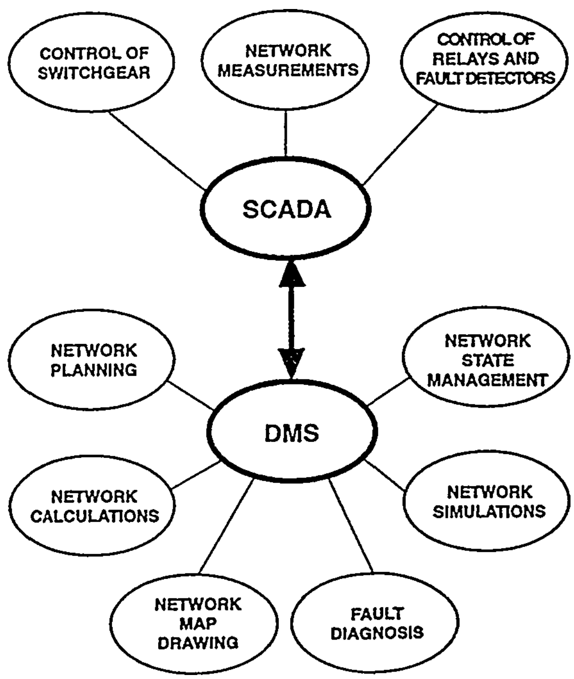


Fig. 1. The integration of a substation telecontrol (SCADA) and a distribution data management system (DMS).

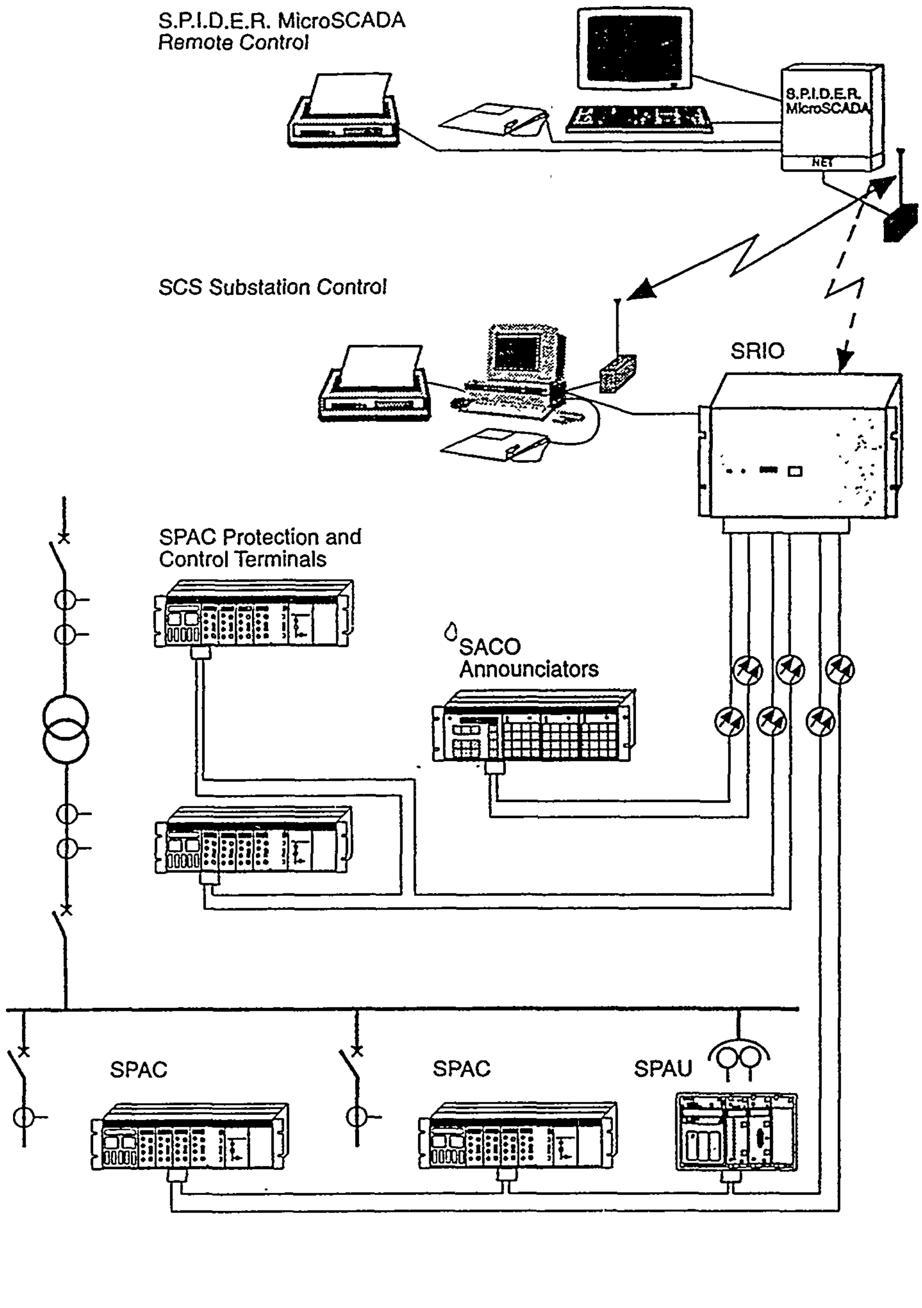


Fig. 2. An example of substation automation based on an integrated telecontrol (SCADA) and relay protection system. SRIO is the control data communicator, SCS is the substation control system, SPAC is an integrated control and protection terminal, SPAU is a voltage relay module and SACO is an alarm unit.

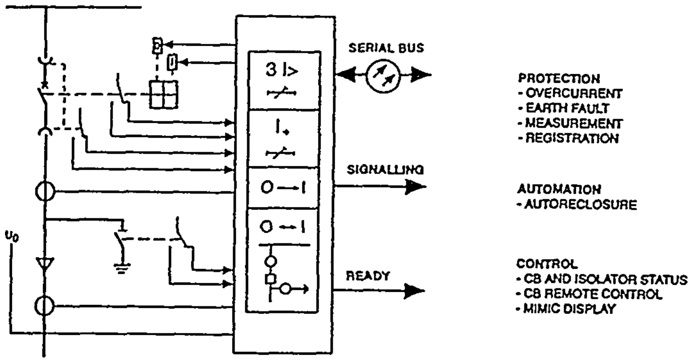


Fig. 3. A feeder bay with an integrated protection and control unit.

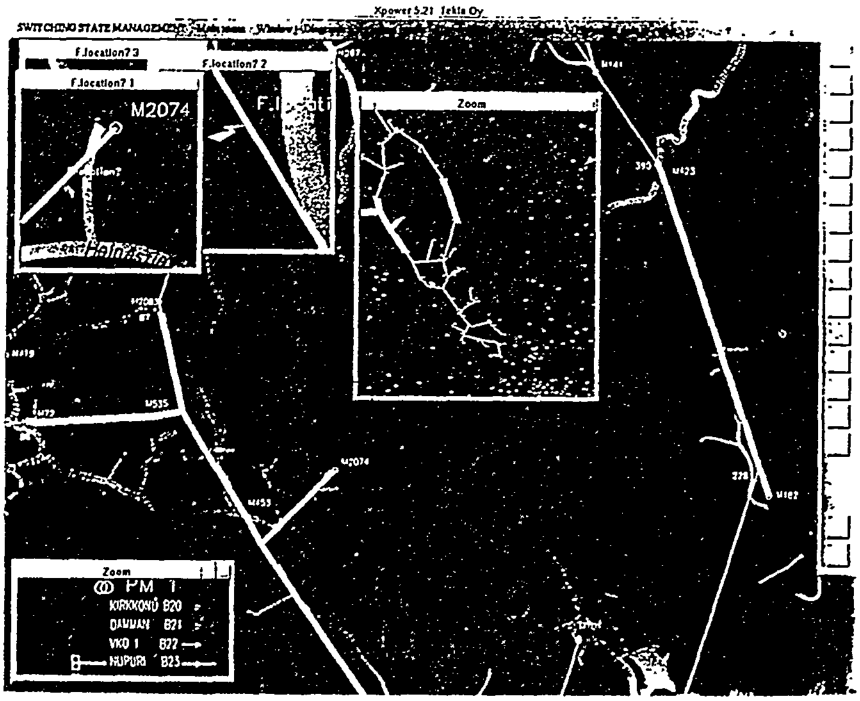


Fig. 4. An example of the graphical display of the automatic fault location system. The possible faulty line sections are shown using a bold line. The most likely fault location within the section is shown using the symbol of lightning.

3 RECORDING REAL CASE DATA OF EARTH FAULTS IN DISTRIBUTION LINES

Seppo Hänninen, VTT Energy

3.1 INTRODUCTION

The most common fault type in the electrical distribution networks is the single phase to earth fault. According to the earlier studies, 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 occur in the networks. For example, the earth fault initial transients can be used for earth fault location. The aim of this project was to collect and analyze real case data of the earth fault disturbances in the medium voltage distribution networks (20 kV). Therefore, data of fault occurrences were recorded at two substations, of which one has an unearthed and the other a compensated neutral, measured as follows:

a) the phase currents and neutral current for each line in the case of low fault resistance

b) the phase voltages and neutral voltage from the voltage measuring bay in the case of low fault resistance

c) the neutral voltage and the components of 50 Hz at the substation in the case of high fault resistance.

In addition, the basic data of the fault occurrences were collected (data of the line, fault location, cause and so on). The data will be used in the development work of fault location and earth fault protection systems.

3.2 RECORDER INSTALLATION

Disturbance recorders were installed at the Gesterby substation of Espoo Electricity Co., where the distribution network is unearthed and at the Gerby substation of Vaasa Electricity Co., where the system neutral is compensated. Substations, with mostly overhead feeders, were chosen as a significant number of circuit breaker operations, during adverse weather conditions, would be likely to occur. 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 of each recorder unit were used. For neutral voltage, in addition to that 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 Gesterby and 0.7 s in Gerby. This contained some periods of history 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 over-wrote old data.

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 to confirm that they were still present and to check if any record had been captured and transferred from 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 the recorder installation is shown in Figure 5.

3.3 RESULTS

During the observation period of about two years at the substations of Gesterby and Gerby, altogether 341 recordings were obtained. This means the disturbance level at the substation busbar and 227 of the recordings were obtained from the feeders which were surveyed. The disturbance recorders triggered every 10th second, if the neutral voltage of the network stayed higher than the triggering level of a recorder. Therefore, the same fault could cause many successive recordings. Later in the text, only one recording of each fault has been taken into account. An electrical fault is 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. Figures 6 and 7 show the number of faults divided into these fault types at the substations of Gesterby and Gerby. The faults, which extinguished themselves, were included in the figures.

3.3.1 Clearing of earth faults

Disturbances of the distribution network were later classified according to the way 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 of 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 again was 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. Figure 8 shows the clearing of the earth faults in an isolated network and Figure 9 shows the same in the compensated network. Due to the difference in neutral earthing and also due to the longer delay of the high-speed auto-reclosing, more faults were extinguished by themselves in the compensated network than in the unearthed network. Also, the triggering level of the disturbance recorders affected the number of these recordings.

3.3.2 Arcing faults

During the observation period, we 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 the instant there is zero current and strikes again when the voltage is re-established. The arcing fault can cause over voltages in the network, which can in the worst case be dangerous to human beings and destroy electrical equipment. Tables 1 and 2 show the peak and average value of the phase voltage which was measured in the network during an arcing fault divided according to how the faults were cleared. Table 2 is sparse, because so few arcing fault occurred in the compensated network.

Table 1. The peak and average value of the phase voltage during the arcing fault in the unearthed network.

Phase voltage	*SE*	*HSAR*	*DAR*	*RC*	*P*
$U_{v,\,max}$	*17.67 kV*	*39.87 kV*	*35.63 kV*	*39.03 kV*	*33.37 kV*
$U_{v,\,mean}$	*17.57 kV*	*37.29 kV*	*34.62 kV*	*39.03 kV*	*33.23 kV*

Table 2. The peak and average value of the phase voltage during the arcing fault in the compensated network.

Phase voltage	*SE*	*HSAR*	*DAR*	*RC*	*P*
$U_{v,\,max}$	*37.56 kV*	-	-	-	*33.31 kV*
$U_{v,\,mean}$	*35.36 kV*	-	-	-	*33.31 kV*

3.3.3 Autoextinction and fault resistances

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 without any auto-reclosing functions could be recorded.

The study showed 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. In these cases, fault resistances were usually so high and the neutral potentials so low, that continued network operation with a sustained fault was possible. The average duration of these faults was 0.54 ms in the compensated network and 0.44 ms in the isolated network. Figure 10 shows the typical curves of neutral voltage and current of this fault type in the unearthed network, in which the disturbance has been caused by a thunderstorm. Figure 11 shows the corresponding curves of the compensated network, in which the disturbance has been caused by windy weather. Figures 12 and 13 show the division of the fault resistances taking into account all disturbance recordings.

Because of a few permanent faults which occurred at the feeders surveyed and to gather more experience, data collection will be continued during the next year.

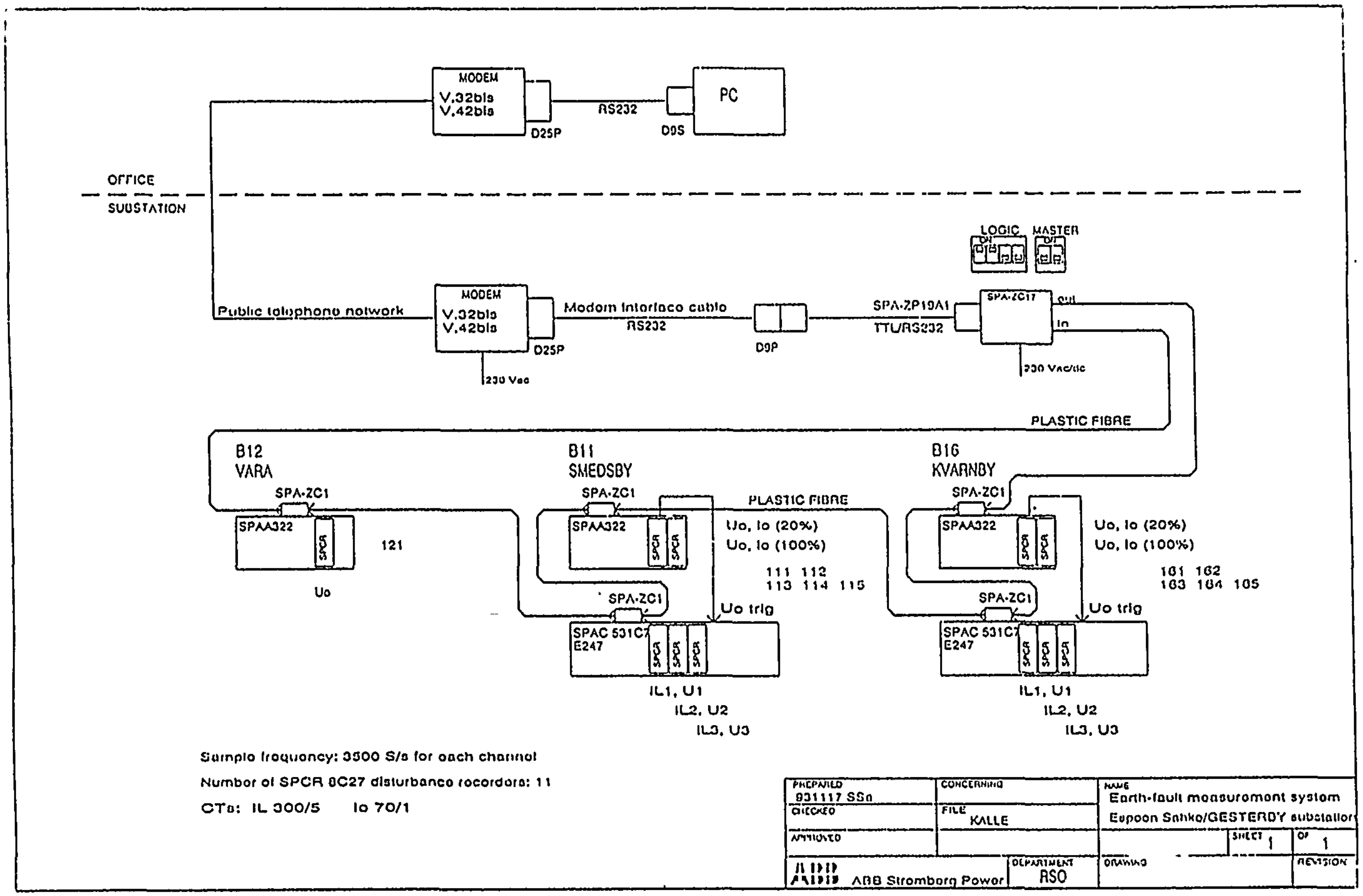


Fig. 5. Installation arrangement of the recorder system at the Gesterby substation.

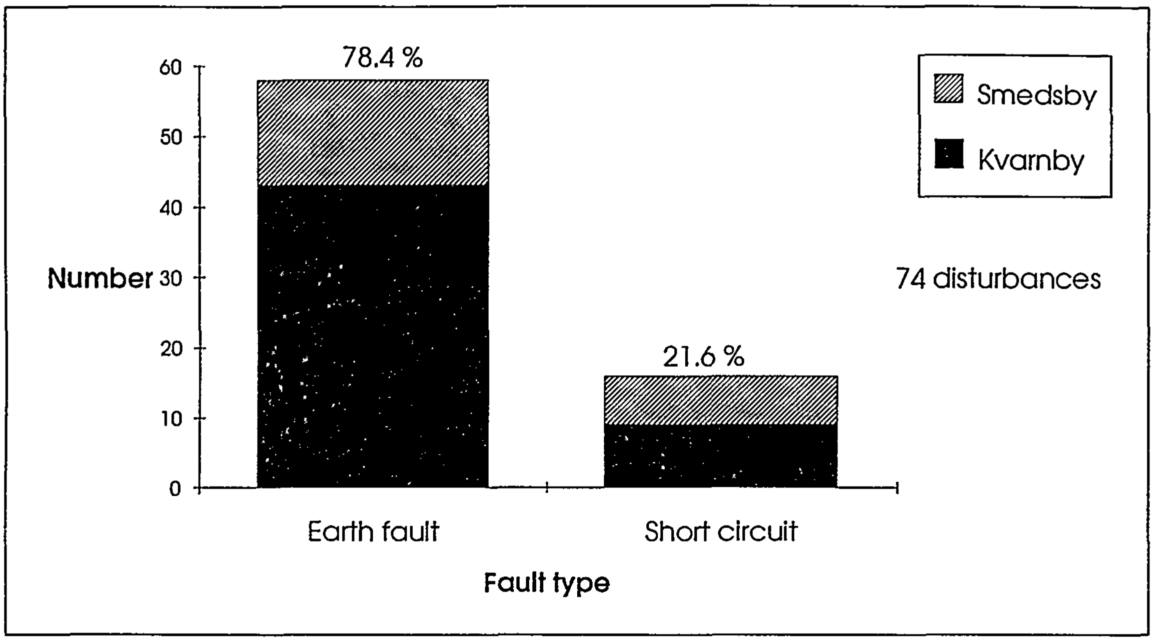


Fig. 6. Number of the faults divided into fault types in the unearthed network.

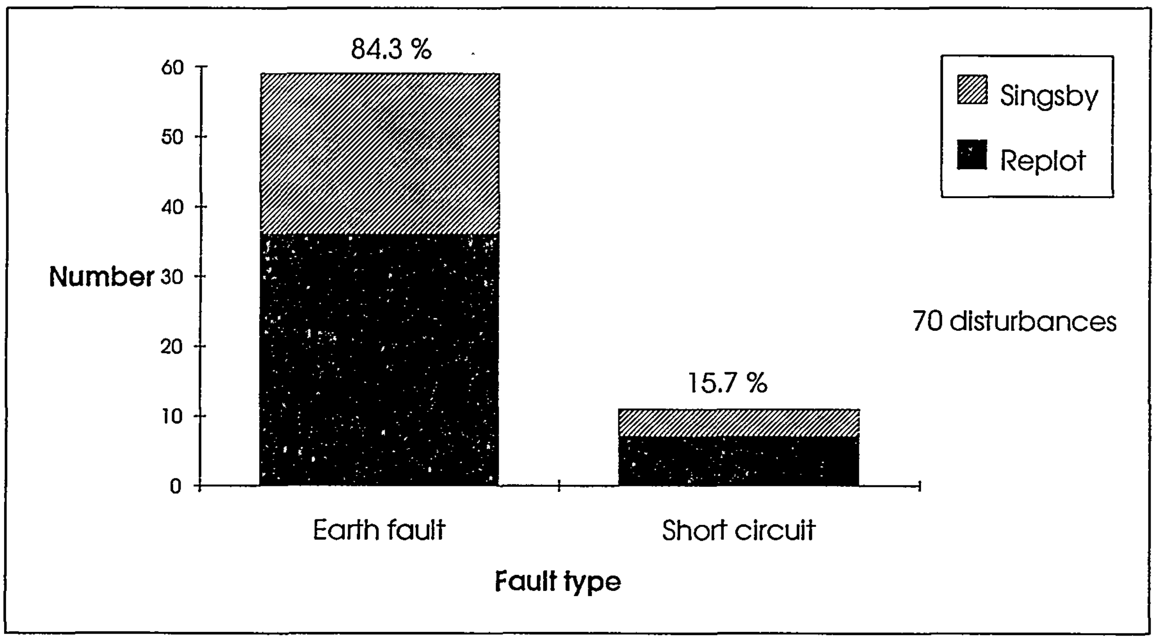


Fig. 7. Number of the faults divided into fault types in the compensated network.

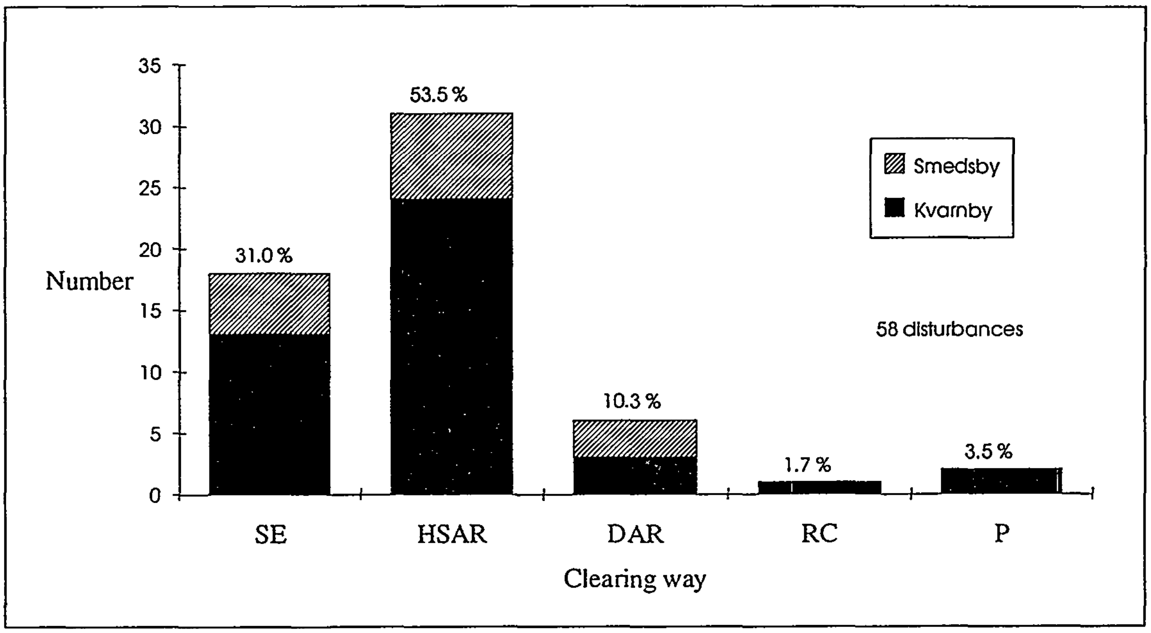


Fig. 8. Number of the earth faults divided into way of clearing in the unearthed network.

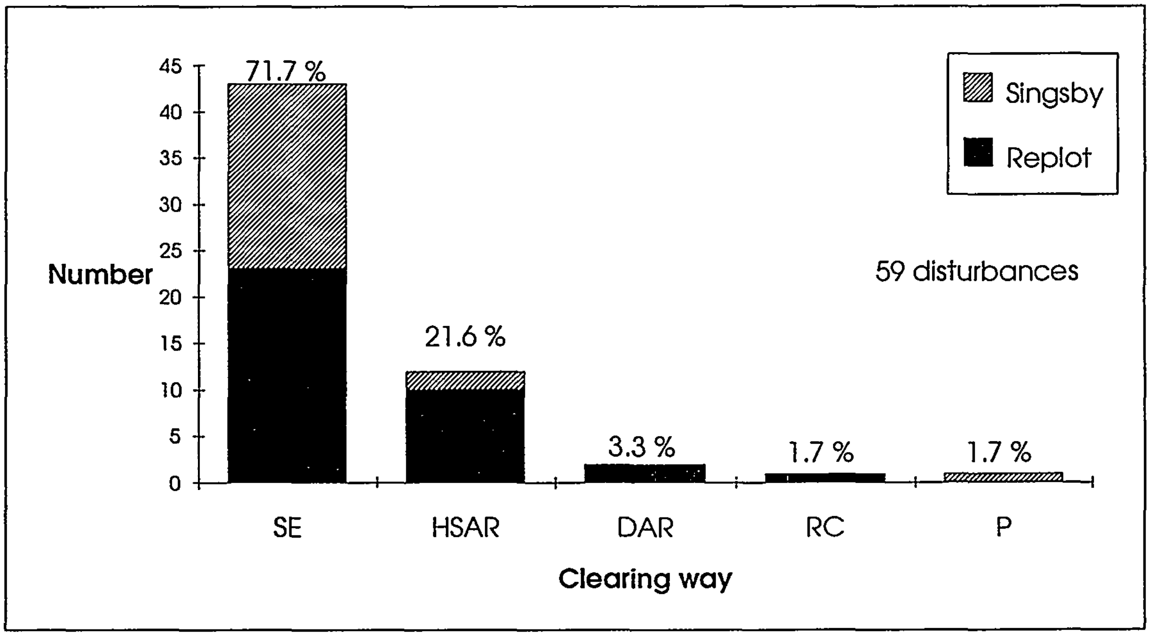


Fig. 9. Number of the earth faults divided into way of clearing in the compensated network.

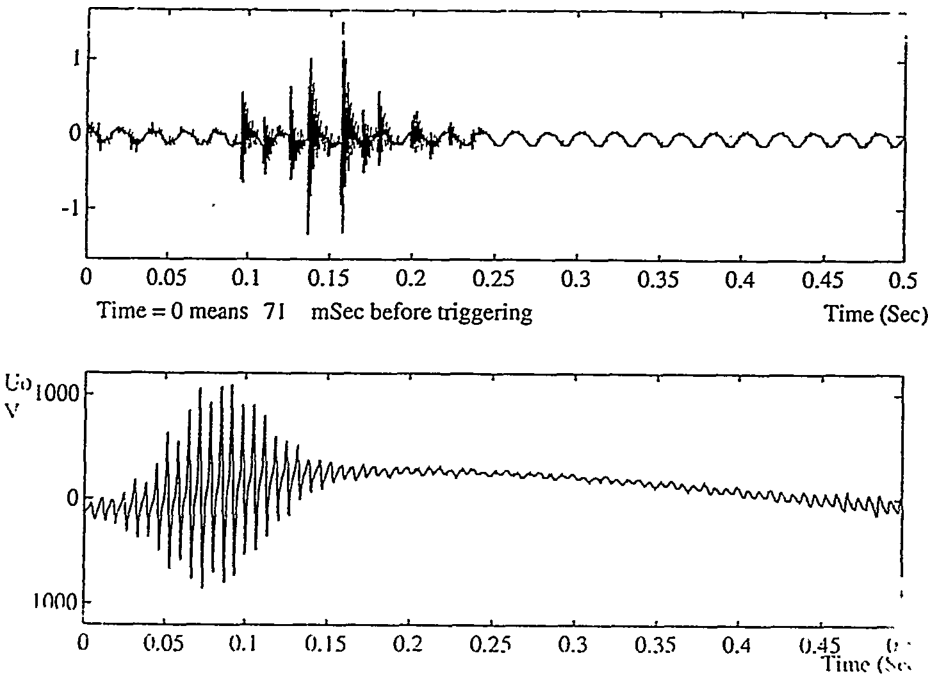


Fig. 10. Neutral voltage and current in an unearthed network. The disturbance was caused by a thunderstorm and the fault extinguished itself.

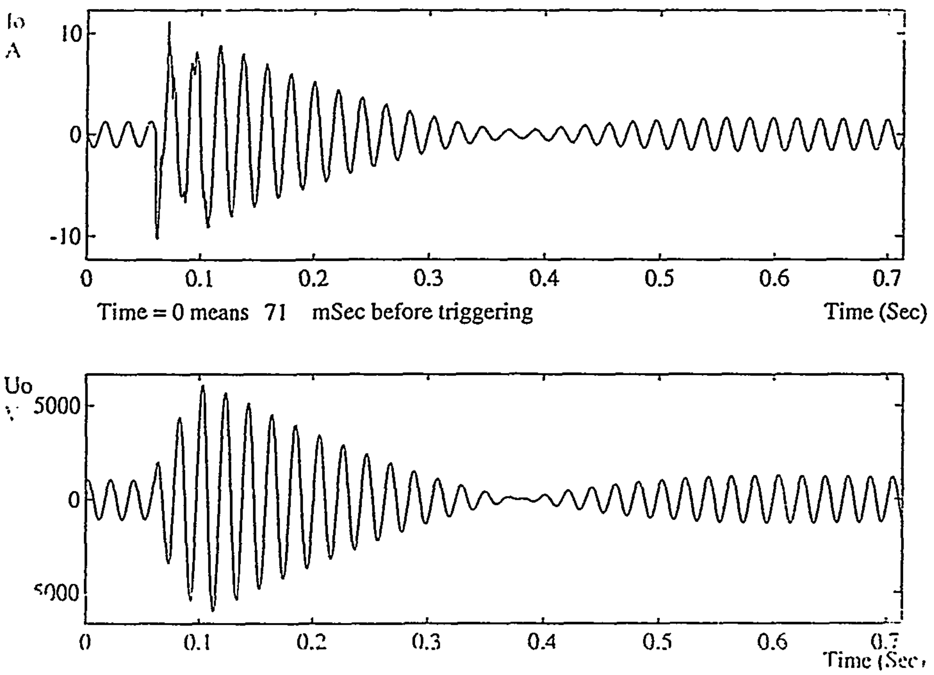


Fig. 11. Neutral voltage and current in a compensated neutral network. The disturbance was caused by windy weather and the fault extinguished itself.

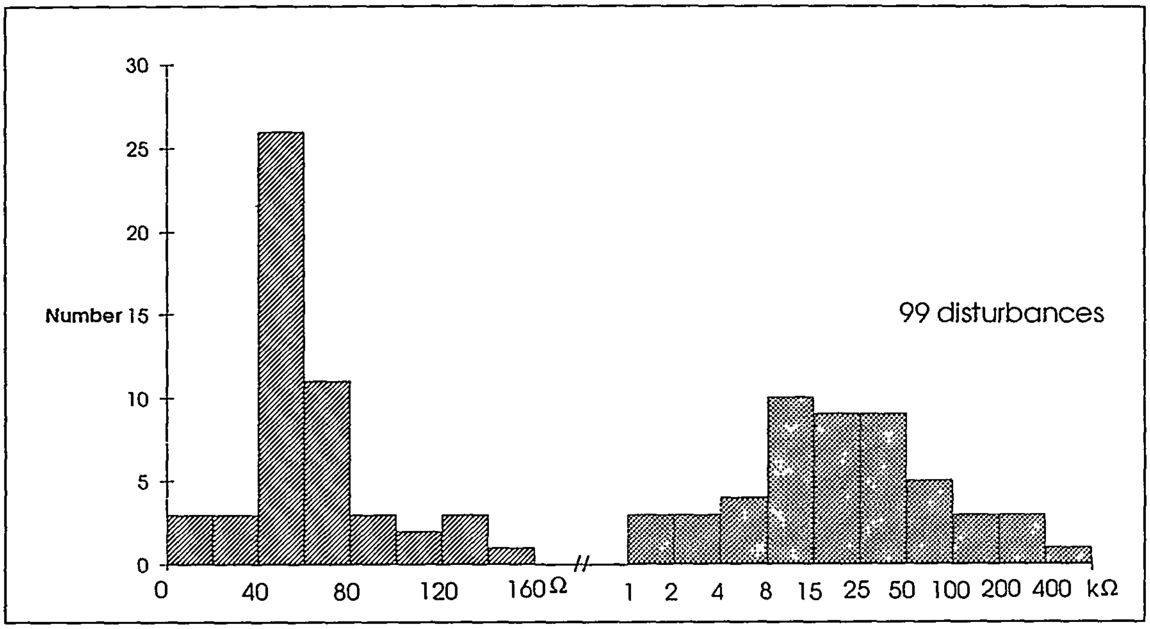


Fig. 12. The division of the fault resistances in the unearthed network.

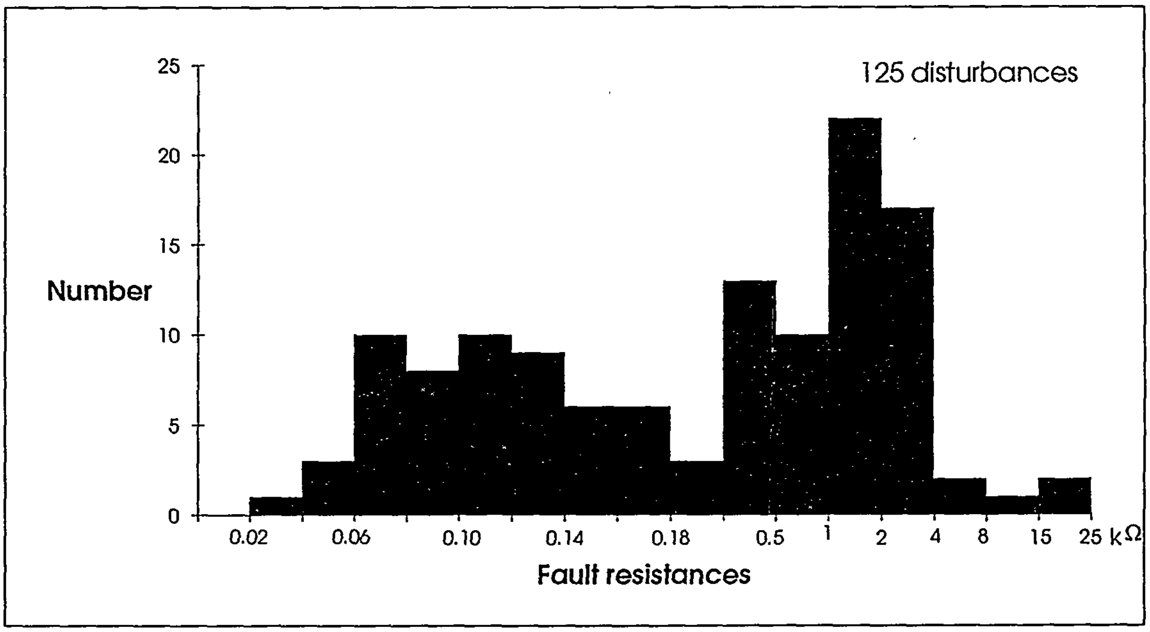


Fig. 13. The division of the fault resistances in the compensated network.

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

Erkki Lakervi, Ari Nikander, Tampere University of Technology

In this 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. First the disadvantages of the rapid autoreclosing functions to customers are studied. Then the influence of the star point impedance to 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 tolerable of 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 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.

4.2 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 can vary largely depending on the day and season, for instance.

An attempt to find out 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 several dozens of rapid autoreclosures happened during the last year over one third of the customers had noticed a large number of interruptions. None of the interviewed customers announced more interruptions than had happened in reality. Usually customers remembered fewer short interruptions than they have in reality experienced. The number of rapid autoreclosing operations is distributed unevenly during different seasons. Major part of the autoreclosures occurs in summer during a thunder 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 last 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.

4.3 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 /19/. 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.

4.4 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 14). 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 /20/.

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.

4.4.1 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 of the method of system earthing on the residual current has been taken into account (Equation 1) /17/. The connection of the sequence networks is illustrated in Figure 15. 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:

$$\underline{I}_e = \frac{3\underline{U}_v\,(R_L 3R_s - \underline{Z}_{mc}\underline{Z}_1)}{2\underline{Z}_1 R_L(3R_s+\underline{Z}_{mc}) + 3R_s\underline{Z}_{mc}(\underline{Z}_1+R_L) + (\underline{Z}_1+R_L)(3R_s+\underline{Z}_{mc})(\underline{Z}_0+3R_f)} \quad (1)$$

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.

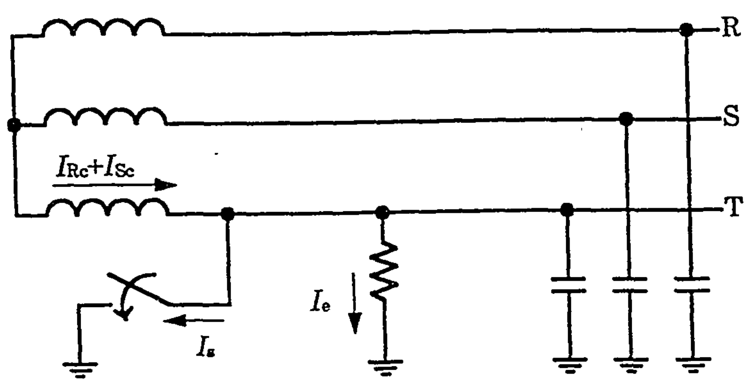


Fig. 14. Principle scheme of phase earthing system. $I_e = I_{Rc}+I_{Sc}-I_s$.

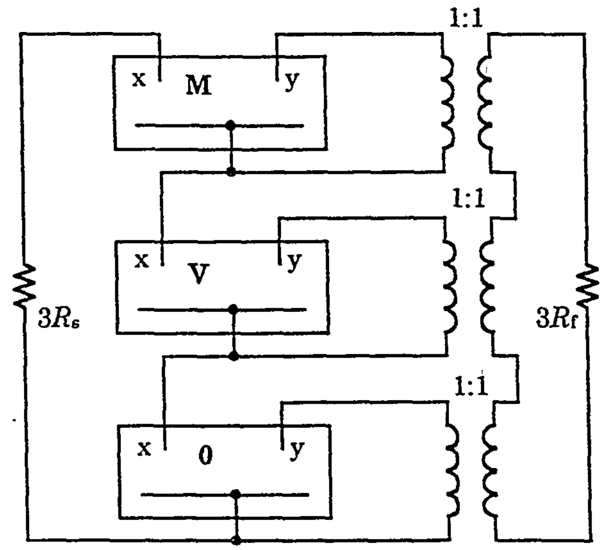


Fig. 15. Combination of sequence networks with phase earthing system. R_s *is resistance of shunt circuit-breaker,* R_f *is fault resistance, x is the location of shunt circuit-breaker and y is the location of the fault.*

4.4.2 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 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 PRIMARY SUBSTATION

Harri Paulasaari, Tampere University of Technology

The target of the project is to develop a system which observes the functions of a protection system by using modern microprosessor based relays. Microprosessor based relays have three essential capabilities: the first is the communication with the SRIO and the SCADA system, the second is the internal clock, which is used to produce time stamped event data, and the third is the capability to register some values during the fault. For example, during a short circuit fault the relay registers the value of the short circuit current and information on the number of faulted phases. In the case of an earth fault the relay stores both the neutral current and the neutral voltage.

5.1 THE DETECTION OF HIGH IMPEDANCE EARTH FAULTS

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 even rise above the phase voltage.

The residual voltage is a sensitive indicator of a high impedance earth fault. Earlier in Finland specialised unlinear transducers were used to produce accurate measuring signals 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. A view of the continuous monitoring system is shown in Figure 17.

The measuring system has been implemented in one utility, Alajärven Sähkö Ltd. The medium voltage network of the utility 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. This residual voltage relay is used in this study, but all the setting values used in the protection are left in the original position.

The utility has a UNIX-based SCADA system. The 20 kV feeders have been provided with new microprocessor based relays. The SCADA system which usually stands in the distribution company's control room, collects fault data via the communication system and RTUs (Figure 16). All the data collection procedures use SCIL-language in the SCADA system.

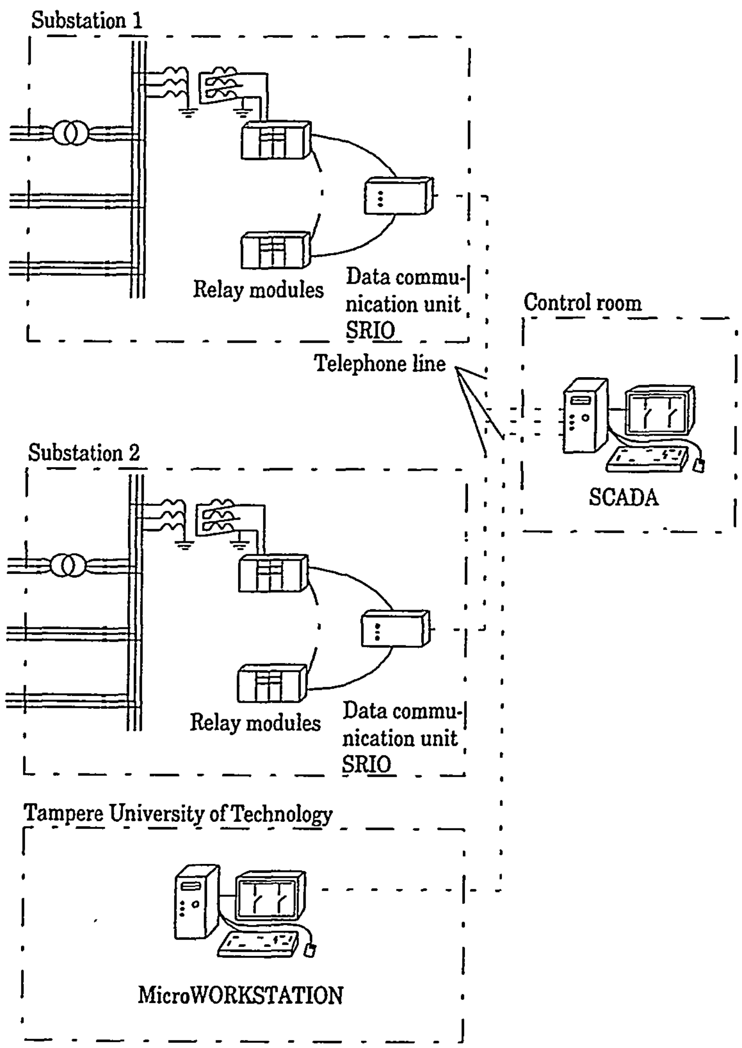


Fig. 16. Connections between the relays and the control room in Alajärven Sähkö Ltd.

Operation of the system:

Relay registrations in fault situation

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 (e.g. 15%). 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. The procedure writes all the collected data to the hard disk of the SCADA computer.

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.

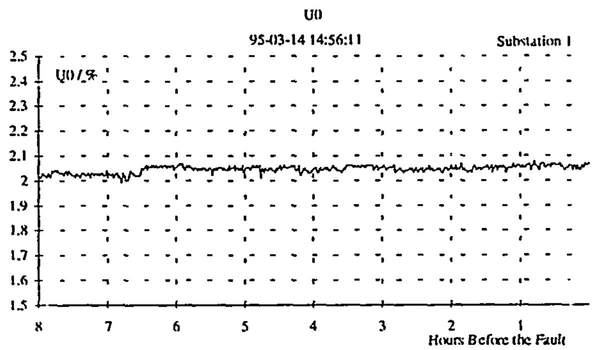


Fig. 17. An example of the measured neutral voltage.

Relay registrations in continuous situation

The SCADA samples the residual voltages once a minute. It stores the values in a data object which includes samples of 48 hours (e.g. 48h*60 sample/hour = 2880 samples). A tool image of the neutral voltage monitoring (Figure 17) utilises this collected data.

The results of registrations can be utilised in high impedance fault detection. Using the registration results and statistics on earth fault currents, it is possible to determine the earth fault currents which can be extinguished by themselves.

5.2 CONTINUOUS MONITORING OF THE PROTECTION SYSTEM

It is possible to determine how the relay should operate by 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.

The monitoring of the function of the protection system can be divided into three levels:

- one feeder terminal
- the primary substation and
- the whole distribution network.

The first goal in this project is to demonstrate the functions of one feeder terminal. So far this has been done at the laboratory of Tampere University of Technology.

The demonstration system

Tampere University of Technology has a relay panel for teaching and research purposes. The panel contains one in feeder and two outgoing feeders (Figure 18). All three feeders are protected 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 system. The SCADA is connected to the SRIO by a serial line. The SCADA system is a MicroSCADA supplied by ABB Transmit. One part of the project has been the implementation of the relays, the SRIO and the SCADA system. This was necessary before the programs developed in the project could be tested.

All the programming needed in the demonstration was done by using SCIL programming language. The first demonstration version has been implemented at the laboratory and will be implemented at Alajärven Sähkö Ltd. at the beginning of 1996.

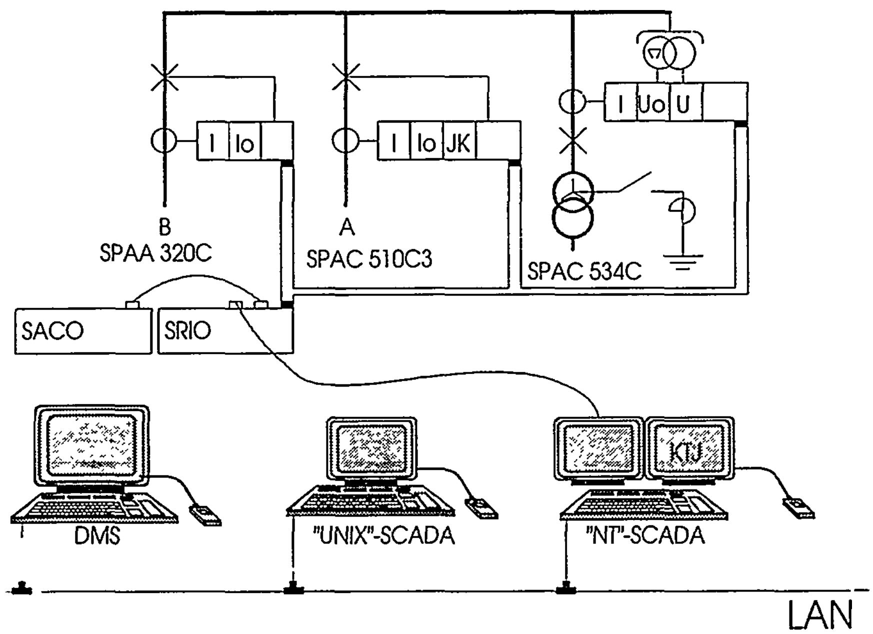


Fig. 18. The relay panel at Tampere University of Technology

6 A DISTRIBUTION MANAGEMENT SYSTEM

Pekka Verho, Pertti Järventausta, Matti Kärenlampi, Harri Paulasaari, Tampere University of Technology, 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 of the traditional 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 centers 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 economic 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.

6.2 AN OVERVIEW OF A DISTRIBUTION MANAGEMENT SYSTEM

This chapter describes the basic models and functions of the intelligent distribution management system, which has been developed in the research project. Distribution management system (DMS) will henceforth mean the system described here, unless otherwise stated. The description can also be seen as a definition of a system for other developers. Therefore the implementation of the system is discussed in the next chapter.

6.2.1 Overall description

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 a telephone answering machine, as illustrated in Figure 19. 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. Such applications are: maintaining of the switching state through the graphical user-interface, real-time network monitoring and optimization based on sophisticated network calculations, short term load forecasting, switching planning, and fault management.

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 (1:200000 and 1:20000) 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. The interactive graphical user-interface of the DMS (see Figure 20) 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

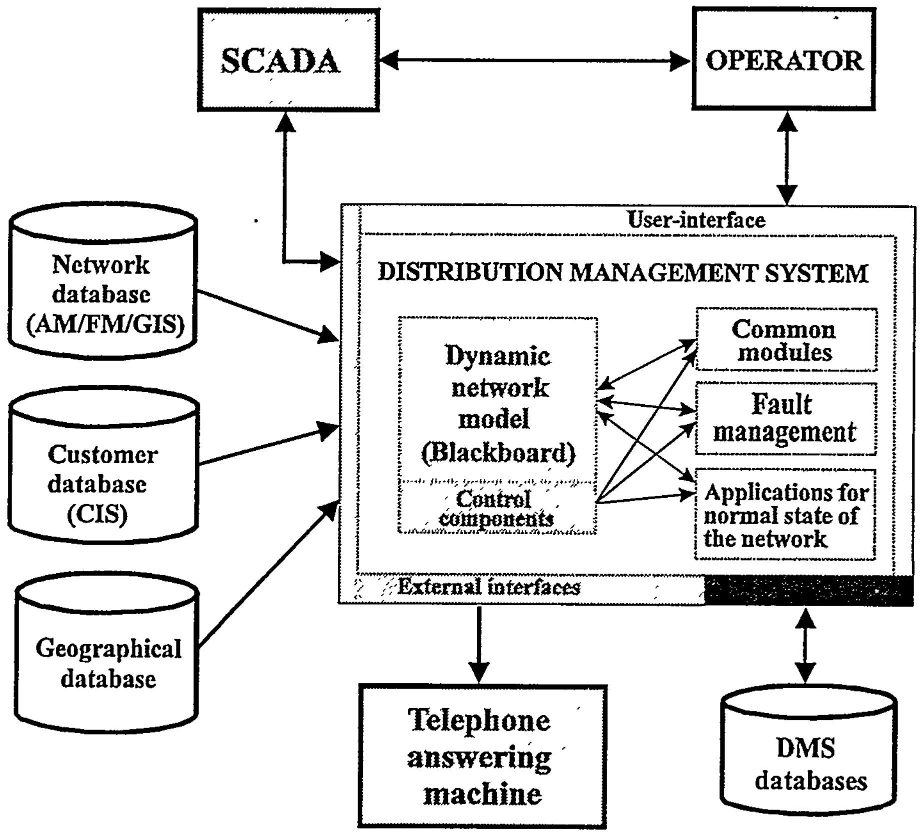


Fig. 19. The operating environment of the distribution management system.

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).

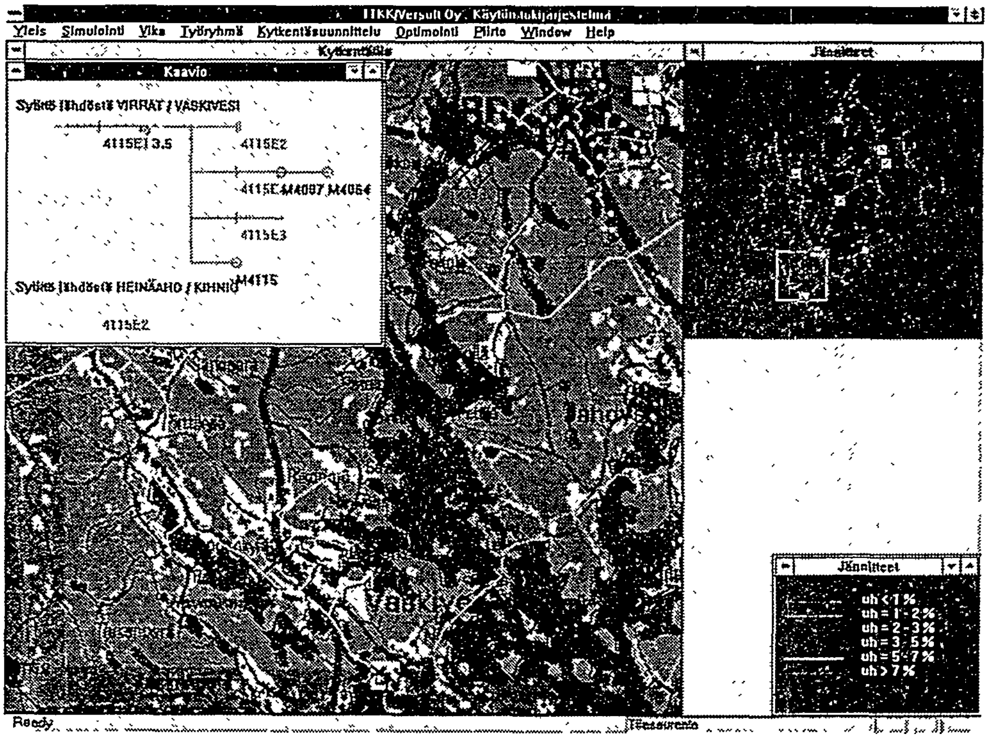


Fig. 20. An overview of the graphical user-interface.

6.2.2 Modeling and computation techniques

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 kinds 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.

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 line sections to be determined without voltage and the feeders that are meshed, are displayed on the screen to help the operator to detect the errors in the switching state.

The developed load flow procedure uses the objects of the 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 dependencies.

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 the 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 by real-time to the SCADA, state estimation is performed at least once an hour and the dynamic load models of the 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.

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.

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 sustained 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.

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.

6.2.3 Functions

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, a line stump can also be set to be 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.

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 being 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 to give information on the reason for the alarm.

To keep the network in an acceptable 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.

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 out on the geographic map on the screen or obtained from the global positioning system (GPS).

Event analysis and fault location

The basic event analysis 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 for the cause of the fault (e.g. arc, fallen tree etc.).

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 μP-based protection relays. The possible fault locations are ranked using information from other sources (e.g. fault detectors, terrain conditions, weather information). Fuzzy sets are used to model the knowledge and information as various membership functions in the inference model.

Fault isolation and restoration planning

Confirmation of the fault location is obtained by interactive experimental switching measures to isolate the faulted line sections. The isolative switching operations are performed in two phases: first by remote controlled disconnectors and then using manual operations. The planning of these operations is supported by the DMS. It proposes the switchings to the operator or switches the remote controlled disconnectors automatically. 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 to interrupted customers. The restoration planning can be made interactively or independently 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 remaining 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.

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 dialogue 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 determine the outage time of each distribution substation. For each outage part the application calculates the number of distribution substations affected and the associated hours, the number of customers affected and the associated hours, and the amount of non-delivered energy. The DMS supports the outage reporting also in maintenance outages.

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 gives the information 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 gives the primary information.

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 by manually operated disconnectors. The planning can be interactive or independent. 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. Once the maintenance is finished, the DMS assists in generating the required outage report.

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.

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 or 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.

There are several alternatives to carrying out the network reconfiguration functions. The objective can be loss reduction or 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 achieved is numeric improvement and the switching sequence.

Since the estimated and forecasted loads include load-voltage dependencies the user can simulate a change in the 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.

6.3 IMPLEMENTATION

The DMS is an MS-Windows program implemented by object-oriented MS-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 Ltd., and AM/FM/GIS by Versoft Ltd. The data interfaces have been developed in co-operation with ABB Transmit Ltd. and Versoft Ltd.

All the applications developed have been tested and almost all are in everyday use in the real control center of the pilot utility, Koillis-Satakunnan Sähkö Ltd.. 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. Relative 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 Ltd. the DMS runs in a PC having a 60 MHz Pentium processor and 16 Mb RAM. The utility has a DOS-based network database system (AM/FM/GIS), a UNIX-based customer database, a UNIX-based S.P.I.D.E.R MicroSCADA running in a PC, and a DOS-based telephone answering machine system of Merlin Systems Ltd.. 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 (see Figure 21). 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.

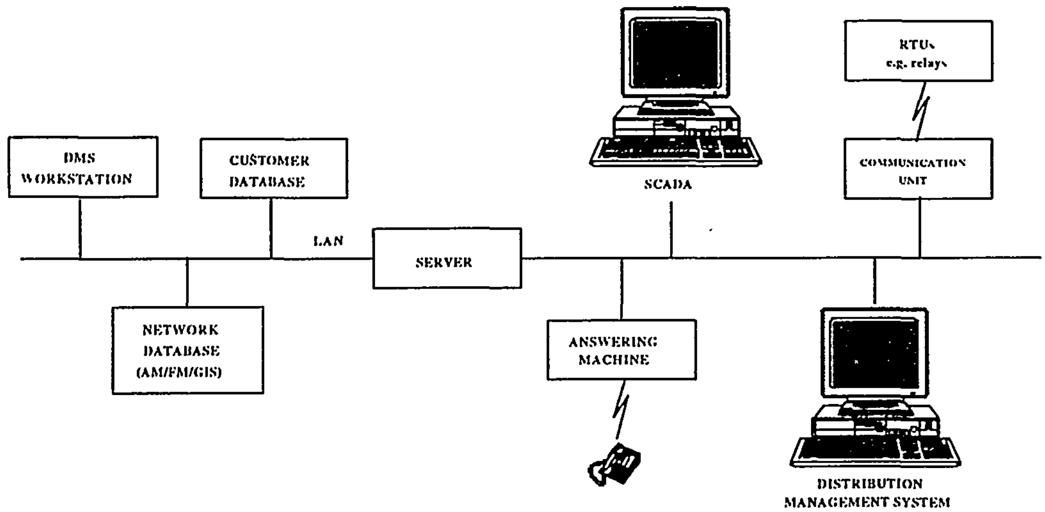


Fig. 21. The integration of the computer systems in the Koillis-Satakunnan Sähkö Ltd.

The communication between the SCADA and the DMS is real-time. The application programs of the MicroSCADA provide the data processing needed by the DMS. The switching state of manually operated disconnectors is also maintained using the simplified network diagram of the MicroSCADA, but no geographical network map is provided. Part of the hard disk of the SCADA has been shared using the NFS (Network File System), and the events and measurements stored in the shared disk can be read from the DMS automatically. The connection is fast enough for the needs of the DMS (i.e. seconds). At present a new connection based on TCP/IP messages is under development to provide a two-way interface. 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.

The research version of the DMS has been revised as a commercial product of Versoft Ltd., and has now been implemented in several utilities (e.g. Satapirkan Sähkö Ltd.). Satapirkan Sähkö Ltd. is a big distribution utility consortium consisting of nine regional member utilities having, for example, 101,964 customers, a 6,505 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 the 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 the DEC VMS operating system. The DMS has been implemented during 1995. The most recent project has been started by Hämeenlinnan Energia Ltd. This case is a good example of openness, since vendors of both the AM/FM/GIS and the SCADA

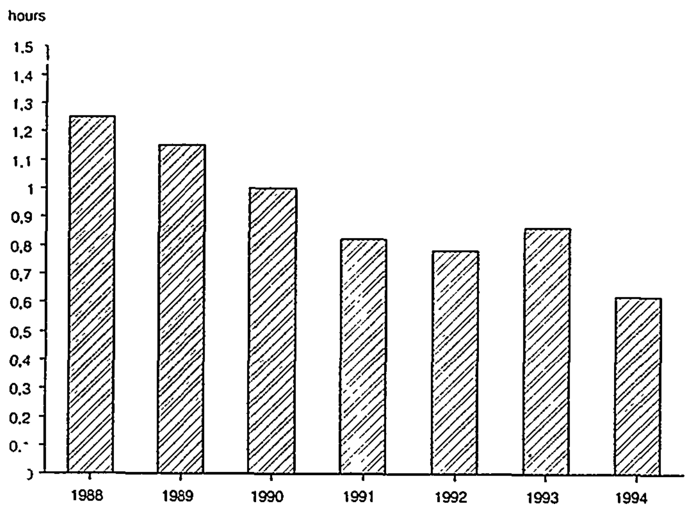


Fig. 22. The mean outage time of a customer per fault at Koillis-Satakunnan Sähkö Ltd.

are different than in previous cases. The UNIX-based AM/FM/GIS has been delivered by Tietosavo Ltd. The Nematic SCADA system of Netcontrol Ltd. is working in the Windows NT operating system. The DMS will be in full operation in autumn 1996.

6.4 EVALUATION OF THE SYSTEM

6.4.1 The benefits of the system

The annual mean outage time of a distribution substation per fault at Koillis-Satakunnan Sähkö Ltd. has decreased considerably in the past seven years, as seen in Figure 22. 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 Ltd. 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.

The experience of using other modules in a real environment is so far rather slight, but laboratory tests have proven the usefulness of these functions. For example, by using an optimization module for network reconfiguration, more than a 10 % loss reduction can be achieved.

Table 3. The benefits of the functions of the DMS.

	voltage level	number of outages	outage costs	working costs	cost of losses	invest-ments
detection of constraint violations & remedial control planning	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

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 the 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 3.

6.4.2 The performance of the system

The response time of the system is sufficient. Because actual computational times depend on the computers used, the situation and the utility size, only approximate times are given based on experience in the test environment. The start-up of the system takes about 15 seconds. The transfer of dynamic data, including SCADA processing, data transfer and network model updating, takes about 5 seconds. The one hour estimation of all feeders takes about 5 seconds and the one hour calculation 2 seconds. The configuration time is one second. In a fault situation the total response time is about 10 - 30 seconds, including the processing in the SCADA, the delay in detection of the event, data transfer and fault diagnosis in the DMS. Each response during the interactive planning of fault isolation and restoration switchings takes 1 - 10 seconds. The longer times are caused by the transition route searching in course of planning the manual operations. The DMS screen containing the background maps is always updated in a few seconds. The time includes the network drawing, too.

The fast response times of the DMS are due to the network modeling technique used. A custom memory resident network representation has been developed in order to provide best efficiency for operational purposes.

6.4.3 Application requirements

The existence of a SCADA, an AM/FM/GIS, a customer information system, and the connections to them are the basic requirements. The connections do not need to work in real-time. For example, in the simple use of the DMS the main SCADA information can be updated by the operator. The more flexible and real-time the connections are, and the more advanced the distribution automation is (e.g. the fault distance calculation is not possible without µP-based relays), the more efficient the application is. However, the utilization level of distribution automation and computer systems is so high in Finland that there are no great technical or economic obstacles to the widespread use of the DMS. In fact, the DMS should be seen as covering and increasing the profitability of the investments in other automation installations.

The threshold to implementing the DMS in a utility is low. Almost all the data can be read in the external systems. The terrain conditions of line sections and the road information should be digitized separately. Connections have to be built to the external systems, but these are quite common between utilites. The interfaces of the DMS have been developed to permit different computer systems of various vendors to be used.

6.5 FUTURE DEVELOPMENTS

During the research work many new needs and functions have been determined for future development. The new functions of the DMS call for more advanced integration of the external systems (e.g. two-way interface between the SCADA and the DMS). So far the DMS has used for the operation of medium voltage distribution networks. As future work the domain will be enlarged to also comprise the low-voltage (0.4 kV) and subtransmission (110 kV) networks. The following describes briefly the new functions, which are to be developed in the near future:

* Automatic switchings in fault management (i.e. fault location and isolation, and network restoration).
* Automatic generation and coordination of protection relay settings.
* More sophisticated optimization methods.
* Management of subtransmission and low-voltage networks from the operation point of view.
* The use of lightning location data in real-time fault location.
* More advanced outage reporting.
* Earth fault location.

This text comprises a general description of the research project "Information system applications of a distribution control center". The results of the project are described in more detail in references /10, 12, 23, 24/.

7 ADDITIONAL FUNCTIONS OF REMOTELY READ kWh-METERS

Pekka Koponen, VTT Energy, Seppo Vehviläinen, Mittrix Oy
and Juha Rantanen, Helsinki Energy Board

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 /22/. 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.

This paper presents a modification of an existing smart kWh-meter. The new version is designed to monitor the power quality also. That is why we emphasise power quality in this paper more than the other roughly equally important application areas. Nevertheless the power quality, including the harmonic content, is an increasing problem /7,9/.

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 23. 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 24, 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 /8/.

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 20 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.

7.4 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.

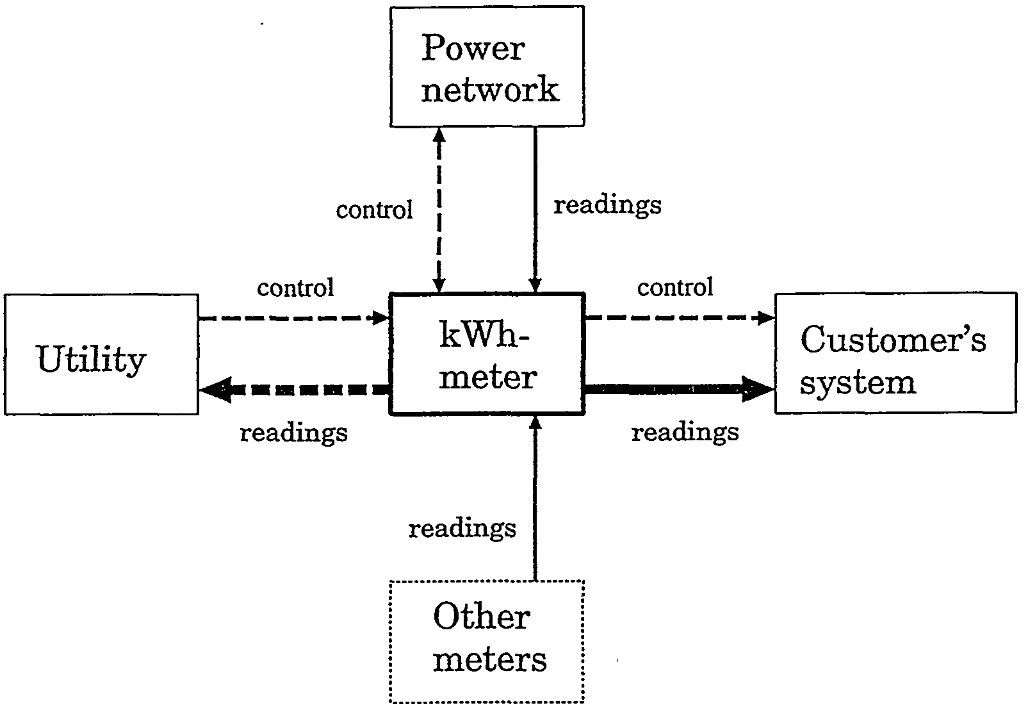
- Develop data models for data communication with the meters.

- 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 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. 23. Interfaces of the kWh-meter.

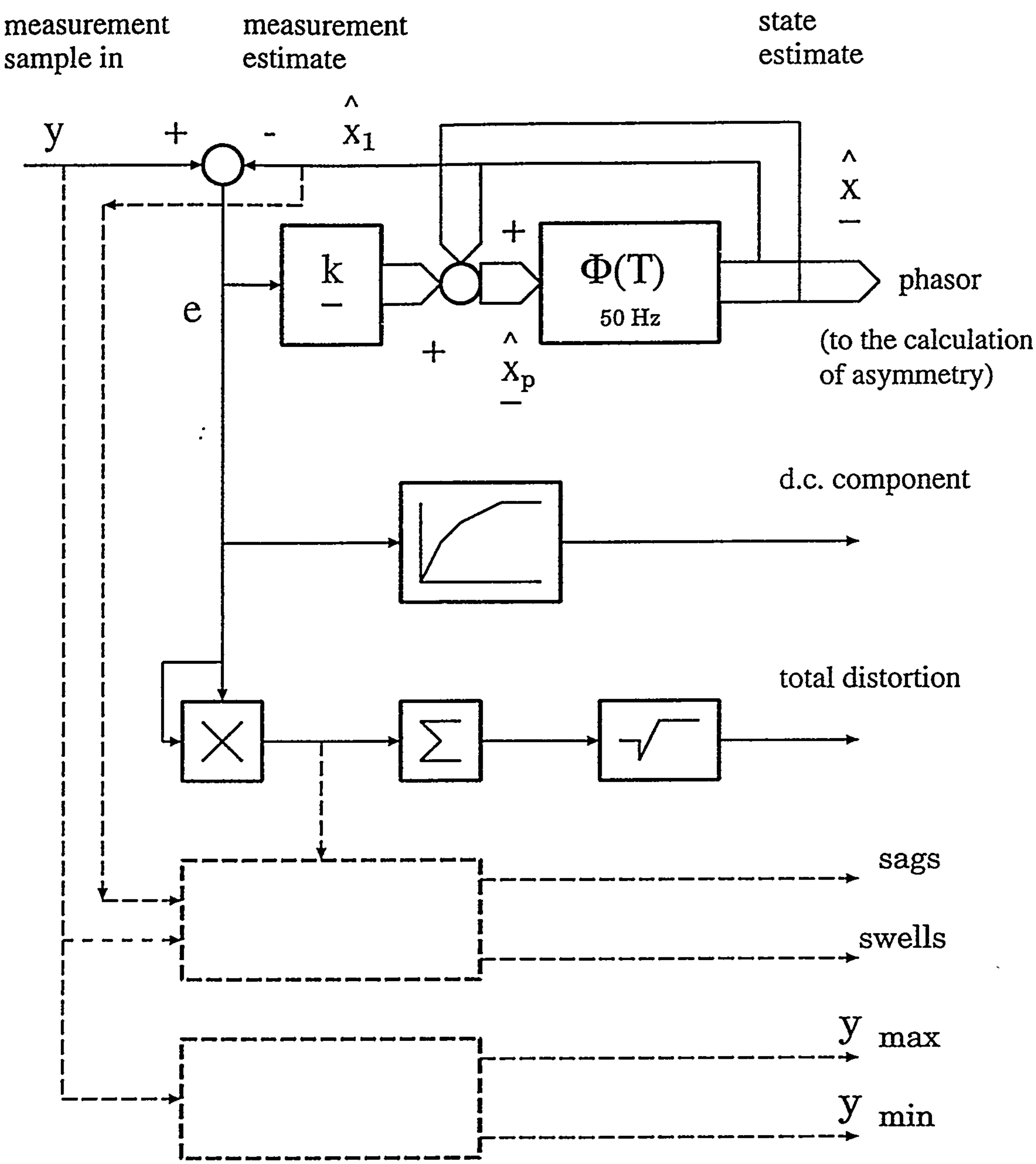


Fig. 24. A method for quality monitoring with a kWh meter when having a sparse sampling.

8 WIRELESS COMMUNICATION TECHNOLOGIES IN DISTRIBUTION AUTOMATION

Juha Takala, VTT Energy

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, error rates, retry times, communication delays, costs etc. will be collected for each communication technology and comparative results will be obtained.

Some field experiments and demonstrations will be made in energy measurement and distribution network remote control. The project is divided in four tasks. Each task is described briefly.

8.1 GSM SHORT MESSAGE SERVICE IN REMOTE METER READING

The principle of the operation is shown in Figure 25. GSM Short Messages are built in the kWh-meter (or in the interface unit), and sent through the GSM network into the Short Message Service Center (SMSC). The interface between the kWh-meter and GSM telephone is Data Card Expander in the pilot project, but can be replaced by Cellular Ware technology (the latter is more economical in larger quantities).

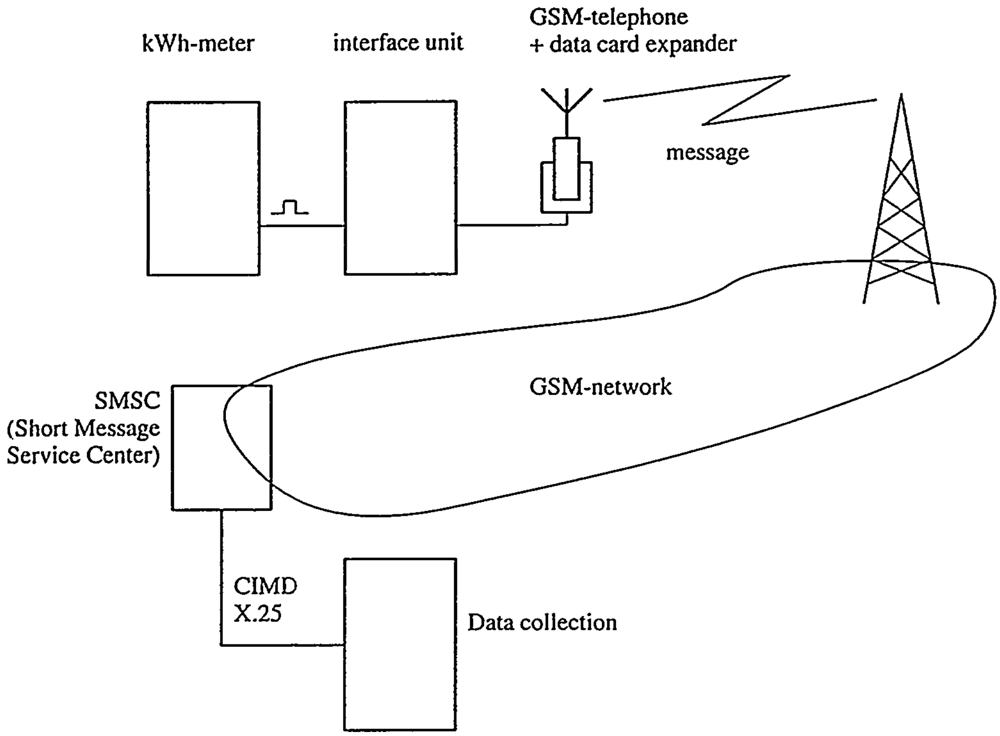


Fig. 25. Principle of using GSM SMS (Short Message service) in remote meter reading.

The meter reading happens in two independent stages:

- Messages from different kWh-meters arrive to the SMSC; several meters may try to send at same time, but the GSM network takes care of this. Each message contains time stamp and information about its origin and the actual meter readings.

- 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.

The partners in this this task are:

- Enermet Oy, a meter manufacturer, implements the interface between the kWh-meter and GSM

- Espoon Sähkö Oy, a distribution utility, provides some customers for testing purposes

- VTT Information Technology makes the SMSC communication software.

At the moment (January 1996) the interface to the SMSC is functional. A definition of message contents and structure is being worked on. A method to keep meter clocks in allowed tolerances has been developed. The first field installations are expected in June 1996.

8.2 NMT DATA IN REMOTE METER READING

NMT (Nordic Mobile Telephone) is a mobile communication technology, that is quite popular in the Nordic (and some other) countries in Europe. It is 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 principle of using NMT data calls in remote meter reading is shown in Figure 26. 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 over 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.

The partners in this this task are:

- Mittrix Oy, a meter manufacturer, implements the interface between the kWh-meter and the 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.

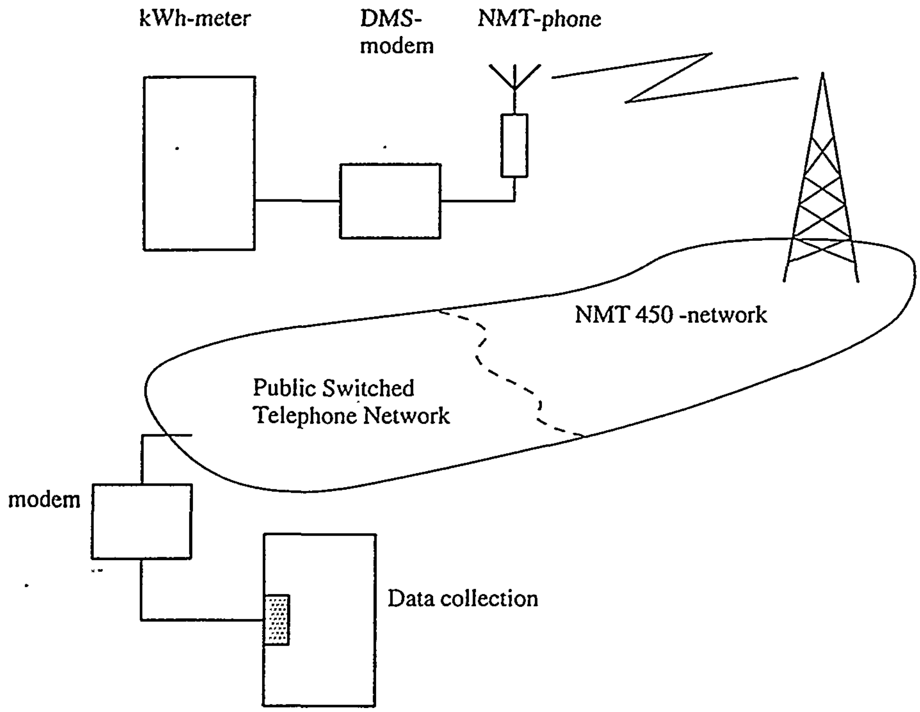


Fig. 26. The principle of using NMT data calls in remote meter reading.

8.3 PACKET RADIO NETWORK IN DISTIBUTION AUTOMATION

ABB has been developing 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 27. The message propagates in the network in "hops" from one node to another. The ABB Paknet operates in such 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 by the Paknet Control Computer (PCC). The current size of the radio network is about ten nodes, and it will grow to about 30...40 nodes in 1996.

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 properties.

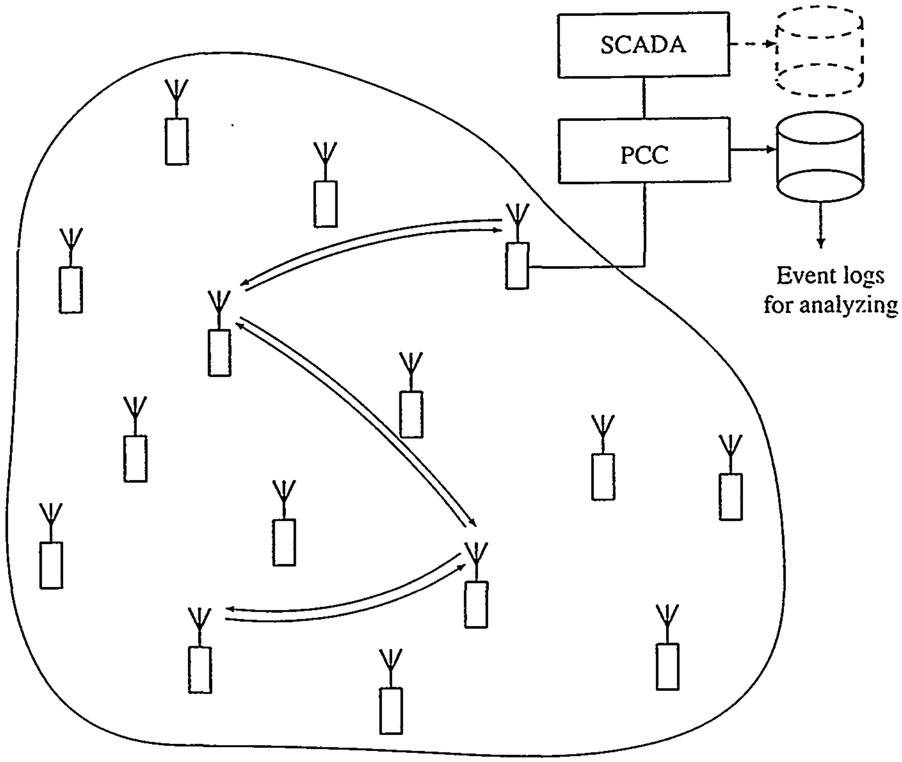


Fig. 27. Packet radio network in distribution automation.

At the moment, the first log files have been received from the utility and the first analyses have been made. Using the results and output of these, the analyzing methods will be fine tuned and the background data (routing map, weather conditions, time of day, etc.) that needs to be available to explain the results, will be specified.

The partners in this this task are:

- Keski-Suomen Valo Oy, a distribution utility, provides the distribution network and packet radio network

- ABB provides technical support and documentation.

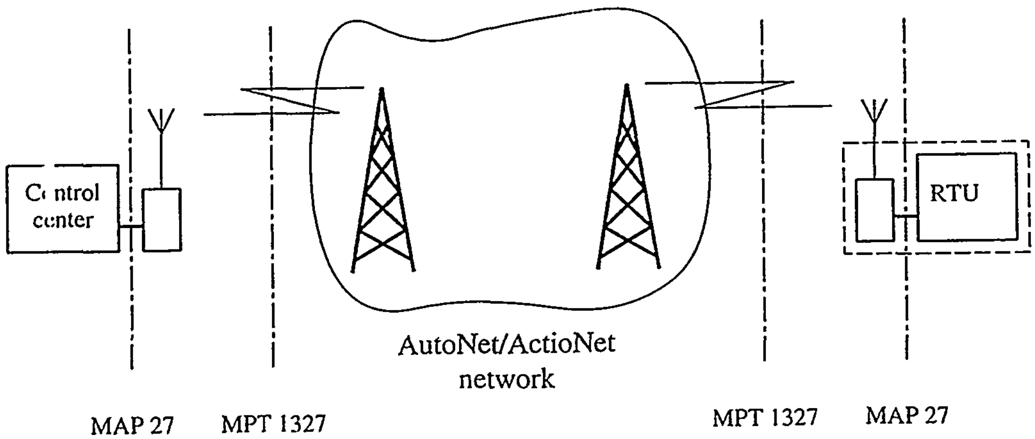


Fig. 28. Autonet / Actionet principle in Distribution Automation.

8.4 AUTONET/ACTIONET IN DISTRIBUTION AUTOMATION

Autonet is a mobile telephone service offered by the telecom operator. The network can transfer normal voice calls and it has a connection to the public switched telephone network (PSTN). The devices that are used to build Autonet infrastructure is 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 the RTU, see Figure 28.

The Autonet/Actionet system is an analog technology in voice communication, but can transfer short messages in the signaling channel. In this project, the usability of the shoer 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. Also the installation of standard devices will be studied.

The partners in this this task are:

- Nokia, the manufacturer of the base stations and radio units, has provided radios, software and documentation.

- Radiolinja, a telecom operator, has provided necessary phone numbers and permission to communicate in the Autonet network.

- Helsinki Energy will provide some test sites.

The current status of the project is such that the communication software can send status messages between the radio units. One RTU will be connected to the remote radio, and will be programmed to echo the test message immediately. The sending end software will measure the delay and build some statistics.

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

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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 /13/, and in the following, only those parts of DSM are taken into account which have direct connections to DA (like load management).

<u>The reduction in outage costs</u> 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 /15/. 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 4. 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 /18/, 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 4 Typical values for average outage costs in different customer classes in Finland (DKK/kW) /18/.

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 /14/.

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 5. 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 29. 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 5.

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.

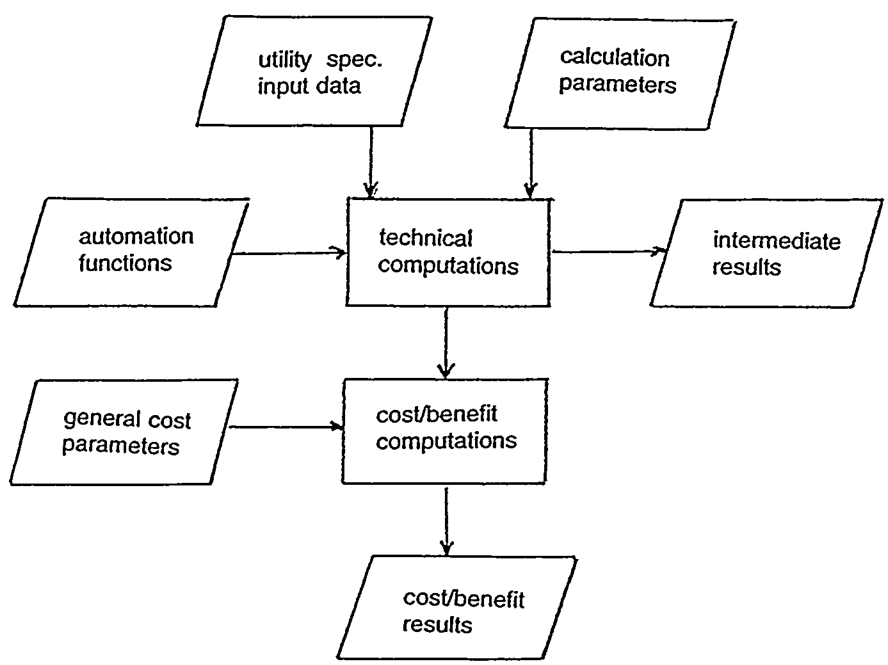

Fig. 29. The structure of the software package for DA/DSM cost/benefit analysis.

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 5, 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 5. *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, VTT Energy

10.1 GENERAL

The consumption of electric energy grows continuously resulting in the growth of the electric load in distribution networks. Utilities need to know where and when in the network the load is close to the limits of the network's capacity. The goal is to quarantee the voltage level to the customers and find the optimal target for network investment. Also the de-regulation of the electricity market needs knowledge of customer loads where direct measurements are not available.

The load research project has produced statistical information in the form of load models to convert the figures of annual energy consumption to hourly load values. The reliability of load models is limited to a certain network because many local circumstances are different from utility to utility and time to time. Therefore there is a need to make improvements in the load models. Distribution load estimation (DLE) is the method developed here to improve load estimates from the load models. The method is also quite cheap to apply as it utilises information that is already available in SCADA systems.

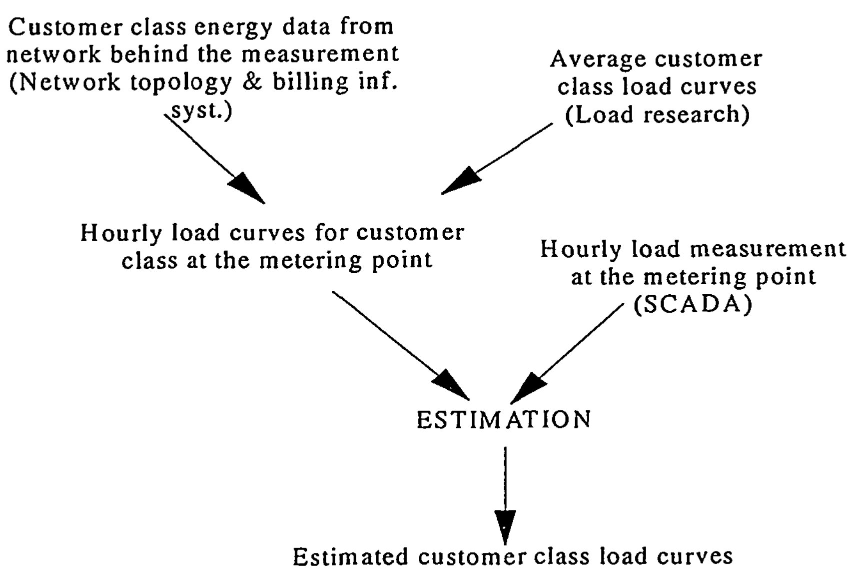

Fig. 30. The data flow of the distribution load estimation (DLE) process.

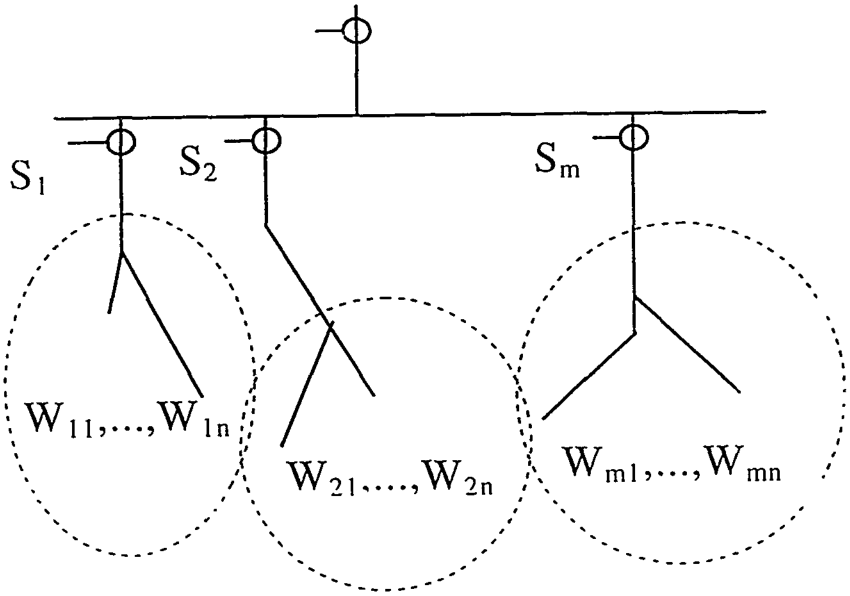

Fig. 31. Distribution station with feeder measurements $S_1 \ldots S_m$. Over an area i the total annual energy of a customer class j is W_{ij}.

In distribution load estimation (DLE) the measurements from the network are utilised to improve the customer class load models. 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. 30.

10.2 THE ESTIMATION PROCEDURE

We assume that the distribution network is radially operated. Each metering meters the load for a specific part of the network. Usually the load metering points are at the primary sub-stations, but metering can also exist deeper in the network. The medium voltage feeders are usually equipped with current metering and the substation primary feeder also has active load metering.

To calculate the hourly load estimate for each customer class we use the linear load model:

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

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

$$z = xW \qquad (2)$$

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 correspond to the factor L_c, which represents the relation 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 the sum of the loads of distinct customer classes *1...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 by W_j

$$W_j = \sum_{i=1}^{m} W_{i,j} \tag{3}$$

The total annual energy consumption of customer classes *1...n* over areas *1...m* is (See Figure 31)

$$\begin{aligned} W_1 &= W_{11} + \cdots + W_{m1} \\ &\vdots \\ W_n &= W_{1n} + \cdots + W_{mn} \end{aligned} \tag{4}$$

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

$$\begin{aligned} z_1 + v_1 &= W_1 x_1 \\ &\vdots \\ z_n + v_n &= W_n x_n \end{aligned} \tag{5}$$

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

$$\begin{bmatrix} z_1 + v_1 \\ \vdots \\ z_n + v_n \end{bmatrix} = \begin{bmatrix} W_1 & \cdots 0 & 0 \\ \vdots & \ddots & 0 \\ 0 & \cdots 0 & W_n \end{bmatrix} \cdot \begin{bmatrix} x_1 \\ \vdots \\ x_n \end{bmatrix} \Leftrightarrow \mathbf{z} + \mathbf{v} = \mathbf{W}_z \mathbf{x} \tag{6}$$

where $\mathbf{z}$ is one column matrix with the number of rows equal to the number of customer classes. $\mathbf{W}_z$ is the diagonal matrix of the total annual energy of the customer classes in the network. $\mathbf{x}$ 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 the customer classes in the corresponding area. The equations can be written again adding the error term e_i

$$
\begin{aligned}
&S_1 + e_1 = W_{11}x_1 + W_{12}x_2 + \cdots + W_{1n}x_n \\
&\vdots \\
&S_m + e_m = W_{m1}x_1 + W_{m2}x_2 + \cdots + W_{mn}x_n
\end{aligned}
\tag{7}
$$

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

$$
\begin{bmatrix} S_1 + e_1 \\ \vdots \\ S_n + e_n \end{bmatrix} = \begin{bmatrix} W_{11} & W_{12} & \cdots & W_{1n} \\ W_{21} & W_{22} & \cdots & W_{2n} \\ \vdots & \vdots & \ddots & \vdots \\ W_{m1} & W_{m2} & \cdots & W_{mn} \end{bmatrix} \cdot \begin{bmatrix} x_1 \\ \vdots \\ x_n \end{bmatrix} \Leftrightarrow \mathbf{S} + \mathbf{e} = \mathbf{W}_S\mathbf{x} \tag{8}
$$

where **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. **x** is one column matrix where the number of rows equals the number of customer classes.

The two matrix equations 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

$$
\begin{bmatrix} \mathbf{z} \\ \mathbf{S} \end{bmatrix} + \begin{bmatrix} \mathbf{v} \\ \mathbf{e} \end{bmatrix} = \begin{bmatrix} \mathbf{W}_z \\ \mathbf{W}_S \end{bmatrix} \mathbf{x} \tag{9}
$$

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

$$
\min \begin{bmatrix} \mathbf{v} \\ \mathbf{e} \end{bmatrix} = \begin{bmatrix} \mathbf{z} \\ \mathbf{S} \end{bmatrix} - \begin{bmatrix} \mathbf{W}_z \\ \mathbf{W}_S \end{bmatrix} \mathbf{x}
$$

For this kind of problem we will use the method of weighted least squares estimation (WLSE), which is widely utilised in the state estimation of transmission networks. The general solution of the WLSE problem for

$\mathbf{z} = \mathbf{A}\mathbf{x}$

is solved by solving the minimum of the sum of the squares

$$
\min\left[(\mathbf{z} - \mathbf{A}\mathbf{x})^{\mathrm{T}} \mathbf{R}^{-1} (\mathbf{z} - \mathbf{A}\mathbf{x})\right] \text{ for } \mathbf{x}. \tag{10}
$$

The solution and the estimate is $\hat{\mathbf{x}}$ when the derivative of the equation is zero

$$-2\mathbf{A}^T\mathbf{R}^{-1}(\mathbf{z}-\mathbf{A}\hat{\mathbf{x}})=0 \tag{11}$$

and the solution will be

$$\hat{\mathbf{x}}=[\mathbf{A}^T\mathbf{R}^{-1}\mathbf{A}]^{-1}\mathbf{A}^T\mathbf{R}^{-1}\mathbf{z} \tag{12}$$

and applied to the DLE problem

$$\hat{\mathbf{x}}=\left[\begin{bmatrix}\mathbf{W}_z\\ \mathbf{W}_S\end{bmatrix}^T \mathbf{R}^{-1}\begin{bmatrix}\mathbf{W}_z\\ \mathbf{W}_S\end{bmatrix}\right]^{-1}\begin{bmatrix}\mathbf{W}_z\\ \mathbf{W}_S\end{bmatrix}^T \mathbf{R}^{-1}\begin{bmatrix}\mathbf{z}\\ \mathbf{S}\end{bmatrix} \tag{13}$$

where the weights in $\mathbf{R}$ are

$$\mathbf{R}=\begin{bmatrix}\sigma_1^2 & \cdots & 0 & 0 & \cdots & 0\\ \vdots & \ddots & \vdots & 0 & \cdots & 0\\ 0 & 0 & \sigma_n^2 & 0 & \cdots & 0\\ 0 & 0 & 0 & \sigma_{S1}^2 & \cdots & 0\\ \vdots & \vdots & \vdots & \vdots & \ddots & 0\\ 0 & 0 & 0 & 0 & 0 & \sigma_{Sm}^2\end{bmatrix}.$$

The weights in $\mathbf{R}$ are variances of models and measurements. This leads to the solution where the estimates of the load models and measurements of higher variance are subject to greater changes from their initial values than those with lower variance.

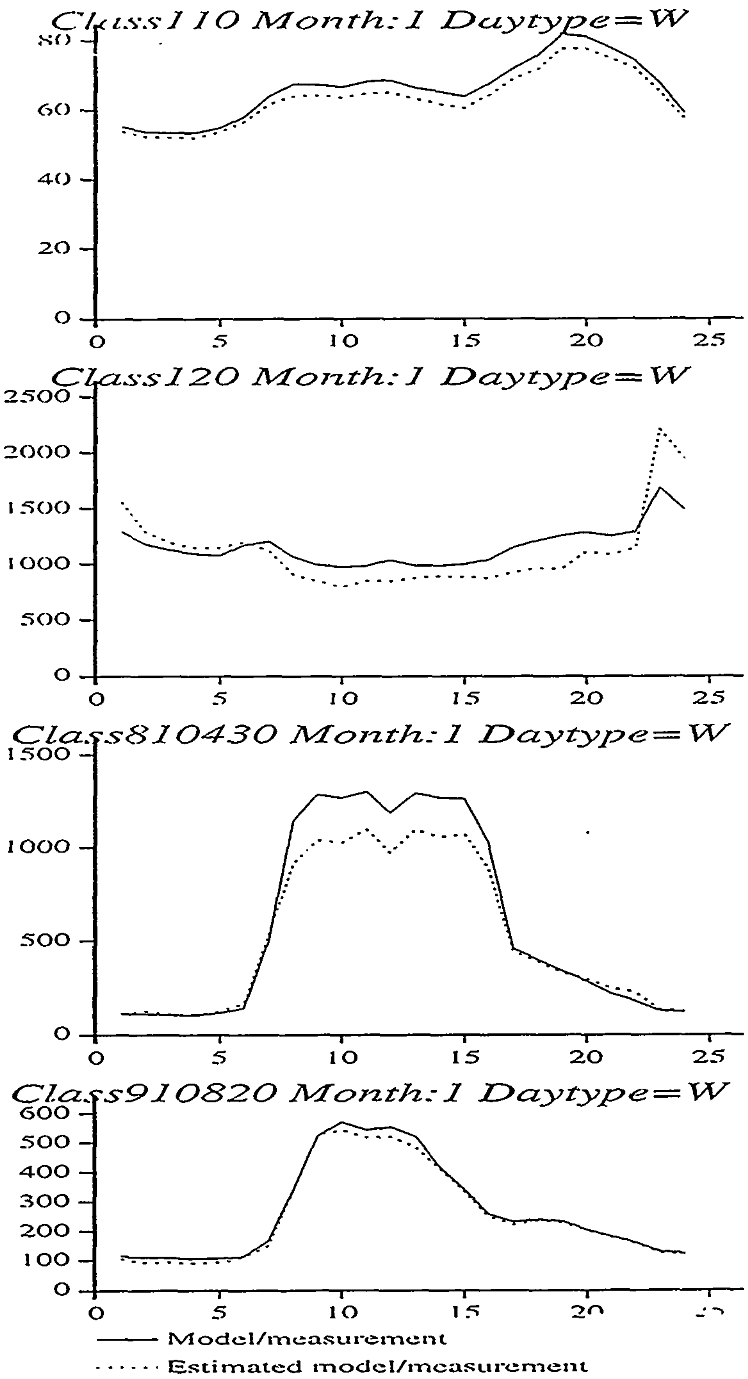

Fig. 32. Load estimation examples for selected load curves. The classes are represented as their numbers: 110 = direct electric heating, 120 = direct electric heating with storage water boilers, 810430 = 1 shift industry (textile) and 910820 = service (private sector).

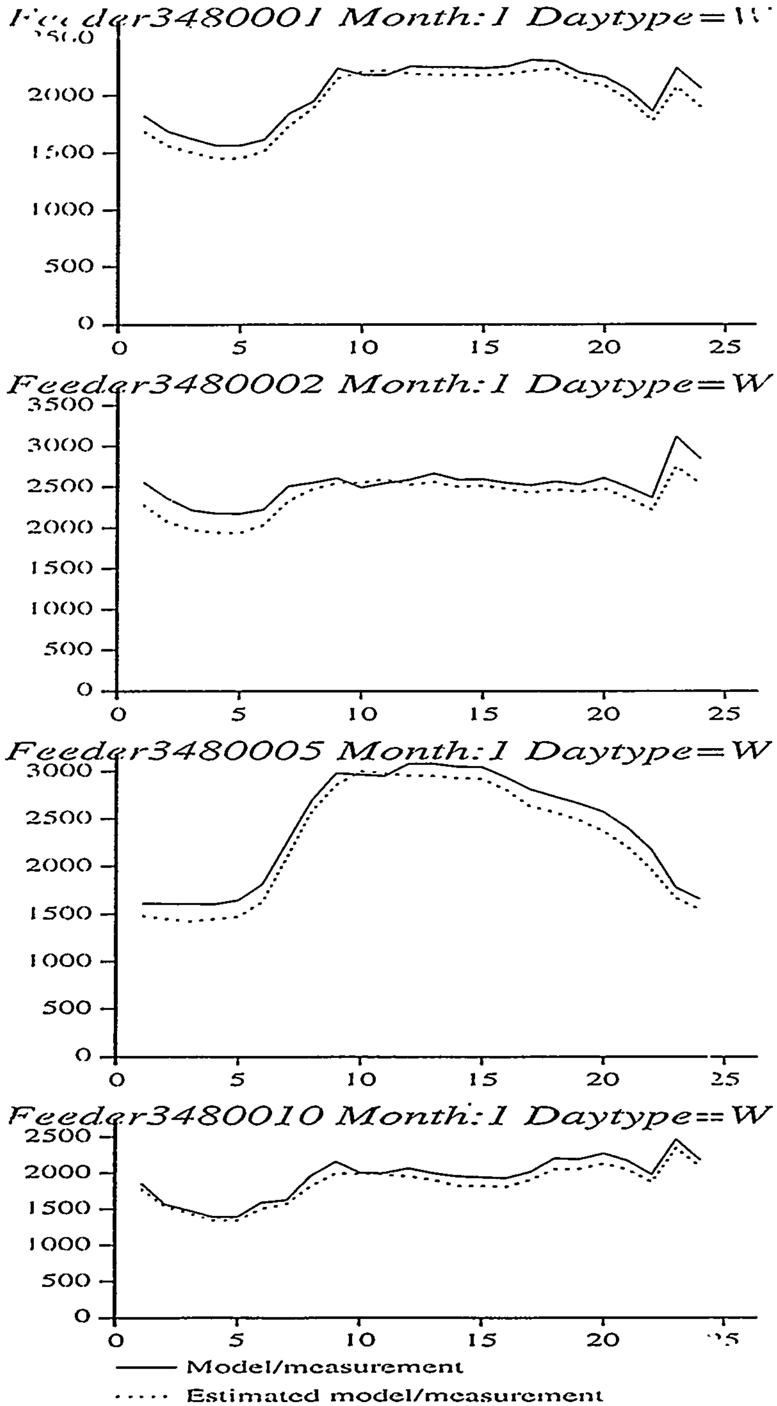

Fig. 33. Load estimation example for a feeder load (S). The result of estimation is represented by a dotted line. The feeder measurement where the values are transformed from current to active power, solid line.

We also apply the model for standard deviation

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

to evaluate the variance $\sigma_P^2 = (s_P)^2$. The value of σ is in general ranging between 30 % ... 100 %. For the 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 as roughly normal distribution the standard deviation is about 1/3 of the maximum error.

For example, when we have a current measurement, the transformation of current to active power includes an error which may be estimated to have a standard deviation of 10% of the absolute value of the measurement. In the case of a direct active power measurement, the error could be 1% or less. Thus the direct measurements have a smaller error variance than the load models.

It is important to note that the absolute values of the weights have no meaning, but the relative differences between weights are important. When in practice the measurements get much smaller variances, the solution will more likely change the estimated load models than the measurements. 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 measurement $\hat{\mathbf{S}}$:

$$\begin{aligned} \hat{\mathbf{z}} &= \mathbf{W}_z \hat{\mathbf{x}} \\ \hat{\mathbf{S}} &= \mathbf{W}_S \hat{\mathbf{x}} \end{aligned} \tag{14}$$

10.3 AN DLE EXPERIMENT WITH FOUR SUBSTATION FEEDER MEASUREMENTS

The previous DLE method has been experimented with using some substation feeder data. Current measurements from four 20 kV distribution feeders and their customer class information has been used to build the equations presented in the previous chapter.

Figures 32 and 33 show an example of how the models change on an average in one month according to the estimation using the four substation current measurements. This method is reliable in the way it splits the error depending on how large a share is represented in one measurement and how high the model variance is. This also means that the small or negligible customer groups are not affected in this estimate.

The curve of the class "Electric heating with storage boilers" (class 120) 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 at the same time (at 22.00).

From these figures we see how the large industry load (class number 810480) measured by 3480002 is totally different, but the other load models are quite similar and only minor changes in daily load patterns are seen. This method is reliable in the way it divides the error to the loads depending on how large a share is represented in one measurement. This also means that the small groups are affected only to a negligible degree.

10.4 LOAD ESTIMATION WITH ONE MEASUREMENT - SIMPLE FORM

The simplest case DLE is one measurement at the feeder of a radial network. Here we analyse this special case more to see if it is possible to formulate a simpler form of load estimation.

The form of the state equations in DLE is, recalling Eq. (9)

$$\begin{bmatrix} \mathbf{z} \\ \mathbf{S} \end{bmatrix} + \begin{bmatrix} \mathbf{v} \\ \mathbf{e} \end{bmatrix} = \begin{bmatrix} \mathbf{W}_z \\ \mathbf{W}_S \end{bmatrix} \mathbf{x} \qquad (15)$$

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

$$\begin{bmatrix} z_1 + v_1 \\ \vdots \\ z_n + v_n \\ \left(\sum_{j=1}^{n} z_j + v_j \right) + e \end{bmatrix} = \begin{bmatrix} W_1 & 0 & 0 \\ 0 & \ddots & 0 \\ 0 & 0 & W_n \\ W_1 & \cdots & W_n \end{bmatrix} \cdot \begin{bmatrix} x_1 \\ \vdots \\ x_n \end{bmatrix} \qquad (16)$$

To solve the problem we minimise the weighted sum of squares of errors in the following form by substituting

$$\begin{bmatrix} \mathbf{z} \\ \mathbf{S} \end{bmatrix} = \begin{bmatrix} z_1 \\ \vdots \\ z_n \\ \left(\sum_{j=1}^{n} z_j + v_j \right) \end{bmatrix} \quad \text{and} \quad \begin{bmatrix} \mathbf{v} \\ \mathbf{e} \end{bmatrix} = \begin{bmatrix} \mathbf{z} \\ \mathbf{S} \end{bmatrix} - \begin{bmatrix} \mathbf{W}_z \\ \mathbf{W}_S \end{bmatrix} [\mathbf{x}] = \begin{bmatrix} v_1 \\ \vdots \\ v_n \\ e \end{bmatrix} \qquad (17)$$

to (10) we get

$$\min\left\{G=\left(\sum_{j=1}^{n}\frac{1}{\sigma_j^2}v_j^{\,2}\right)+\frac{1}{\sigma_S^2}e^2\right\} \tag{18}$$

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

$$e'=\left(\sum_{j=1}^{n}v_j\right)+e \Leftrightarrow e=e'-\left(\sum_{j=1}^{n}v_j\right) \tag{19}$$

Now we state the problem differently: What are the values of v_j to minimise the weighted sum of square error when the total difference e' is given? Or in other words: How should the error e' be divided to the models to fill the WLS-criteria?

Substituting Equation (19) to Equation (18) we get

$$\min\left\{G=\left(\sum_{j=1}^{n}\frac{1}{\sigma_j^2}v_j^{\,2}\right)+\frac{1}{\sigma_S^2}\left(e'-\sum_{j=1}^{n}v_j\right)^2\right\} \tag{20}$$

The minimum is found by solving the set of partial derivatives

$$\frac{\partial G}{\partial v_j}=0 \quad j=1\ldots n$$

The result for v_j is

$$v_j=\frac{\sigma_j^2}{\sigma_S^2+\sum_{i=1}^{n}\sigma_i^2}e' \tag{21}$$

Substituting this to the formula

$$z_j+v_j=W_jx_j \tag{22}$$

we get the estimate in the form

$$\hat{x}_j=\frac{1}{W_j}\left(z_j+\frac{\sigma_j^2}{\sigma_S^2+\sum_{i=1}^{n}\sigma_i^2}e'\right) \tag{23}$$

This result is useful for many practical network calculation applications where, for example, the voltage drop of 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:

A 20 kV feeder was measured as having a current of 20 A on Wednesday, March 15 1995 between 14.00-15.00. The bus voltage was 20.7 kV. From the network information system we get the information that the feeder was feeding five customer classes according to Table 6.

Table 6. The annual energies of the measured feeder.

Customer class	*MWh/a*
1. 1-shift industry	*1000*
2. Agriculture	*200*
3. Residential with direct electric heating	*1000*
4. Storage heating	*400*
5. Residential	*1800*
Total	*4400*

From the load models obtained from load research we obtain the relation between annual energy and a corresponding hour's load as shown in Table 7.

Table 7. Customer class load models and expected load P_j and standard deviation s_j.

Customer class	L_c *W/MWh*	s_{Lc} *W/MWh*	P_j */kW*	s_j*/kW*
1. 1-shift industry	*297*	*133*	*297*	*133*
2. Agriculture	*90*	*64*	*18*	*64*
3. Residential with direct electric heating	*135*	*81*	*135*	*81*
4. Storage heating	*24*	*15*	*10*	*15*
5. Residential	*101*	*70*	*182*	*70*
Total			*642*	

This information is found in the files of the Finnish load research project. The models are from the calendar year 1990. Thus we apply day March 14th which is actually a Tuesday, because we don't make any distinction between working days.

From the current metering we get the active power by first assuming the load factor cosϕ = 0,9. Thus we get $P_S = \sqrt{3} \cdot 0{,}9 \cdot 22 \cdot 20.7 = 710\text{kW}$. The average error of the standard error σ_P will be approximated as 7 %, thus σ_P = 50 kW. The error between models and measurement e = 710 - 642 kW = 68 kW will be delivered relative to the variances of the models and measurement. The result is shown in Table 8.

Table 8. The original model class loads, variances, error/correction v_j and new estimated value.

Customer class	Class load P_j/kW	Variance $\sigma_j^2/(kW)^2$	v/kW	$\hat{P}_j$ / 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. Storage heating	10	225	0,5	10.5
5. Residential	182	4900	9	191
Total	642		62.5	704.5

As we see the difference between models and measurements can be quite easily divided between models. This method takes into account both the difference of the sizes of the customer classes and the uncertainty of the model and measurements 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 investment. 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 for customer level recordings is reduced compared to the conventional load research.
- When the electricity markets are free from regulation the DLE brings on-line information from the loads while 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.
- Better network load estimate for maximum utilisation of the capacity of the network and for most profitable targets for network investment and service.

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

- Accurate knowledge of feeder load gives an 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 a load management system (actual timing of load control, and estimation of the effects of load management on the total load).

11 DISTRIBUTION ENERGY MANAGEMENT SYSTEMS IN THE ENVIRONMENT OF DE-REGULATED ELECTRICITY MARKET

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11.1 INTRODUCTION

In Finland, the electricity market was de-regulated the first of November 1995. For distribution companies this means big changes, since the network operation and energy selling activities will be separated. The customers have the right to choose between several power suppliers, the network owner having the duty to transmit the electricity on an equal basis to all customers.

In this paper, the problems of energy management of the distribution companies in the new situation are first discussed. The topics covered are: the estimation of energy balances, optimization of energy purchase, short-term trade management and tariff design. Also the problems with demand side management actions are outlined.

A computer prototype system for distribution energy management (DEM) is then presented. The basic functions of the DEM system are first considered. These are the processing of measurements and load models, and the on-line estimation of energy balances. Next, the functions needed for energy trade and energy management are studied. Finally the technical structure of the computer system is outlined and the interfaces to other computer systems, including substation SCADA, distribution data management system, customer information system and the remote metering system are described.

11.2 THE DE-REGULATED ELECTRICITY MARKET IN FINLAND

The purpose of de-regulation of the electricity market, is to increase the efficiency in the energy system. According to the de-regulation act, the businesses of electricity generation, trade and transmission and distribution should be separated by January 1, 1996 /6/. The network companies will remain as monopolies, but they are obliged to transmit the power, sold by any trading company, to their customers (Figure 34). Therefore, a point tariff system has been established /5/. A customer is connected to the network in one place and has access to the whole network of the country. For those customers, who wish to participate in the free market, the network company must arrange, at a reasonable cost, an hour based metering. The market is first free for customers having a peak demand of 500 kW or higher. In 1997, the market will be free for all customers.

Two main types of power selling agreements exist: fixed and open. In the first type, the power to be delivered is agreed on beforehand, and the hourly demands are fixed. Here, if the actual power does not equal the agreed quantity, the customer has to purchase the difference by some other means. In the latter type, the open supply, the hourly demands are settled afterwards according to the measured consumption. Here the trading company also has a duty to supply power to all the customers in the area where they have the dominate position. For this, there must be an open and public tariff system, where the customers are free to choose any tariff offered.

An authority, called the Electricity Market Centre (EMC), has been established. The EMC will monitor the rates of the network companies, and will also ensure, that the technical condition of the distribution systems is at a reasonable level. It will also monitor the tariffs of the trading companies, in order to keep the prices at a reasonable level.

The free electricity market is expected to reduce the price of electricity for the larger customers. The likely consequence to the smaller customers is, that the prices will remain the same, or may increase somewhat. The market also is likely to itemize and to reveal the actual components of power supply costs. Hence, it will guide the structure of the power system and the trading, generating and network operating companies into a more efficient direction.

11.3 ENERGY MANAGEMENT IN THE FREE MARKET

11.3.1 Load estimation

The on-line knowledge of loads is essential for the optimization of power generation and other electricity purchase. However, in the free market, all the customers which participate in the competition are not necessarily metered by real time. The hourly demands are obtained only afterwards, possibly with a delay of several weeks.

The problem of delayed load data can be solved by the on-line estimation of the customers´ loads. The estimation is based on the past recordings of the hourly demands, customer class load models and, if available, on-line measurements in the distribution network /25/. As shown in Figure 35, a typical example of on-line measurements are the loads of medium voltage distribution feeders. By combining the measured data with the load models, an estimate can be produced for the hourly demands of the customers. This information can most conveniently be produced by the network company, who has the access both to the network and to the customer related measurements.

From the power trader´s point of view, an alternative approach is to combine hourly measurements of single customers to the load models /26, 27/ and possibly some parameters like the outdoor temperature. This approach is the only possible, when information from the network company is not available. This is the likely situation for those customers, who have an open supply, but are located in the distribution area of some competing power trader.

11.3.2 Energy balance management

Two different energy balances must be defined, the technical one and the commercial one. The technical electricity balance is a summation of the real-time estimates and short term forecasts of the loads of all the customers supplied by the trader concerned. This information is used for the real time optimization of the power purchase.

The commercial electricity balance is the energy balance based on the authorized power measurements, which are taken from the on-site energy meters. Since these meters are typically read periodically, the commercial energy balance also is derived only after a certain delay.

The proposed system for energy balance management in Finland is such, that the major traders have to announce beforehand the estimated hourly demands, i.e. technical electricity balances of the customers located in the other traders´ areas. In the case that the announced demand differs from the one obtained by the commercial balance calculations, the seller of the power is responsible for the deviations. Most likely, these deviations will be settled by the market marginal price.

This arrangement leads to two types of difficulties with regard to the real time energy and load management. In the case of single customers with an open supply but located in another trader area, the selling company has to deal with the uncertainty of the load magnitude. The risk included depends on how well the load is known and what the price of the deviation is.

Another, and perhaps a more severe problem, is the uncertainty in the announced estimates of the loads of the other traders' customers in the area of the selling company concerned. Because of this, the selling company has difficulties in estimating its own customers' demand on a real-time basis.

The introduction of the free electricity market also affects the power purchase practices of the retail selling companies. So far the utilities have been looking for the competitive edge by co-operating in bulk power buying. Several buyers have joined together in order to increase their mass in the market. Up to date, the bulk tariffs have included fixed limits for power demand only. In the future, the bulk power buyers will have to adjust to the energy limits also. That is, there will be agreements where the amount of energy supplied also is fixed.

A new feature also is the short-term energy trade. Now it is possible to exchange energy in the spot market either by bilateral agreements or via a power pool. In the latter case, several companies have joined together in order to optimize their power purchase and generation for their common benefit. In the near future, it is likely that this kind of pool will be established on a national, or even multi-national level. To benefit from the spot market, the traders have to be able to predict the short term market price and to optimize their own purchase and market activities. This requires new computerized tools for real-time energy management.

The de-regulation also affects the practices in electricity retail selling. In the area, where the selling company has a dominate position, there must be open and public tariffs. These must be accessible for all the customers, who wish to have an open supply. In the case of any other customers, the trading company is free to make any type of selling agreements. This leads the company to compare in more detail the actual costs in the bulk power purchase, caused by different types of retail customers. One of the main objectives is to minimize the risks both in the tariff system and in the individual sales agreements.

So far, demand side management (DSM) has, in Finland, been based mostly on direct load control and multi-rate tariffs. The controlled load has typically been electric space heating and water boilers. The free power market will open new possibilities also for DSM actions. These will be possible through increased metering with the associated data transmission capabilities and because of more freedom in agreements between the customer and the utility.

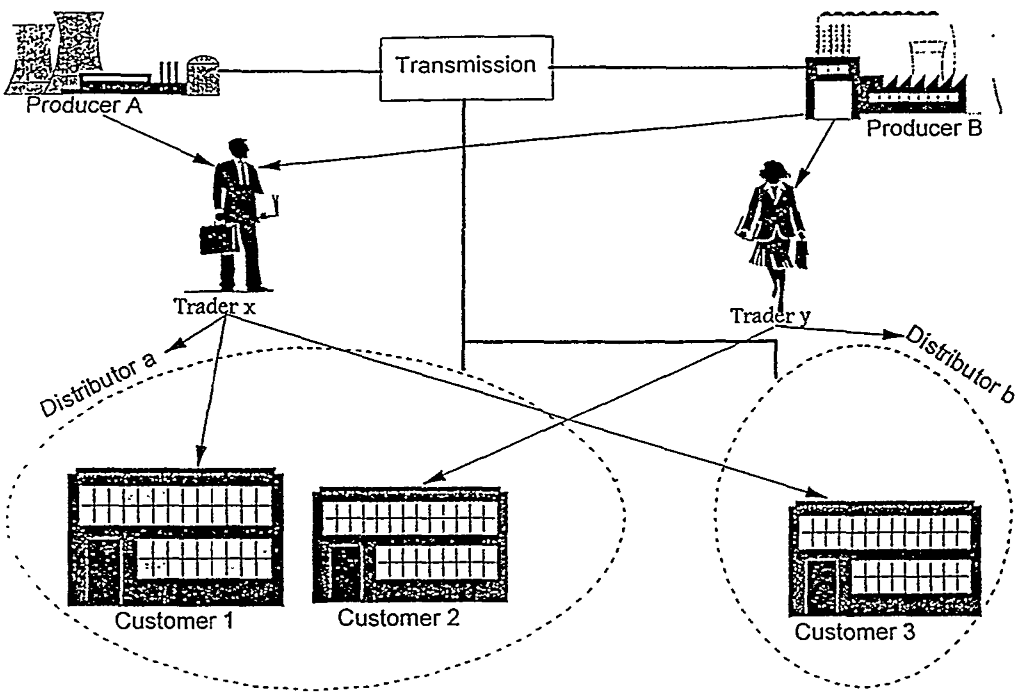

Fig. 34. In the de-regulated power market, the businesses of electricity generation, trade and transmission and distribution are separated. The network companies will remain as monopolies, but they are obliged to transmit the power, sold by any trading company, to their customers /6/.

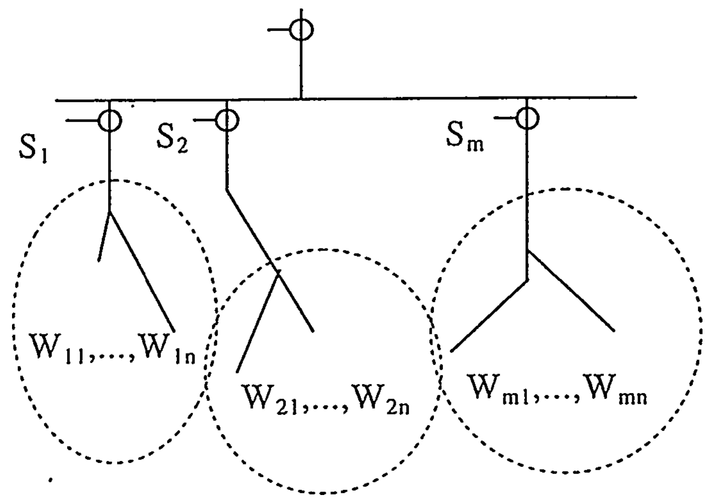

Fig. 35. The minimum level of information needed for on-line load estimation includes the power measurements at the medium voltage substation feeders and annual energies for different customer categories.

Also direct load control can be utilized more efficiently in the de-regulated market. In the case, where the trading company participates in the spot market, the load control system can be used in order to increase the power that can be sold to the market. This significantly extends the utilization of the load control capacity. However, with regard to the load control, there also are new problems. These are because the on-line information concerning peak power magnitude includes a higher degree of uncertainty than before. To mitigate this problem, the utility must have new computerized tools for peak load estimation and for the optimization of the load control procedures.

Table 9. 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 handling for billing*
6.	*Selling / buying agreement management*
7.	*Monitoring and control of distributed generation*
8.	*Electricity purchase optimization*
9.	*Pool price forecasting*
10.	*Short-term (spot) electricity trade optimization*
11.	*Tariff design and retail sales planning*
12.	*Load control optimization, direct and indirect*
13.	*DSM planning functions*
14.	*DSM impact verification*
15.	*DSM impact models (pseudoloads)*

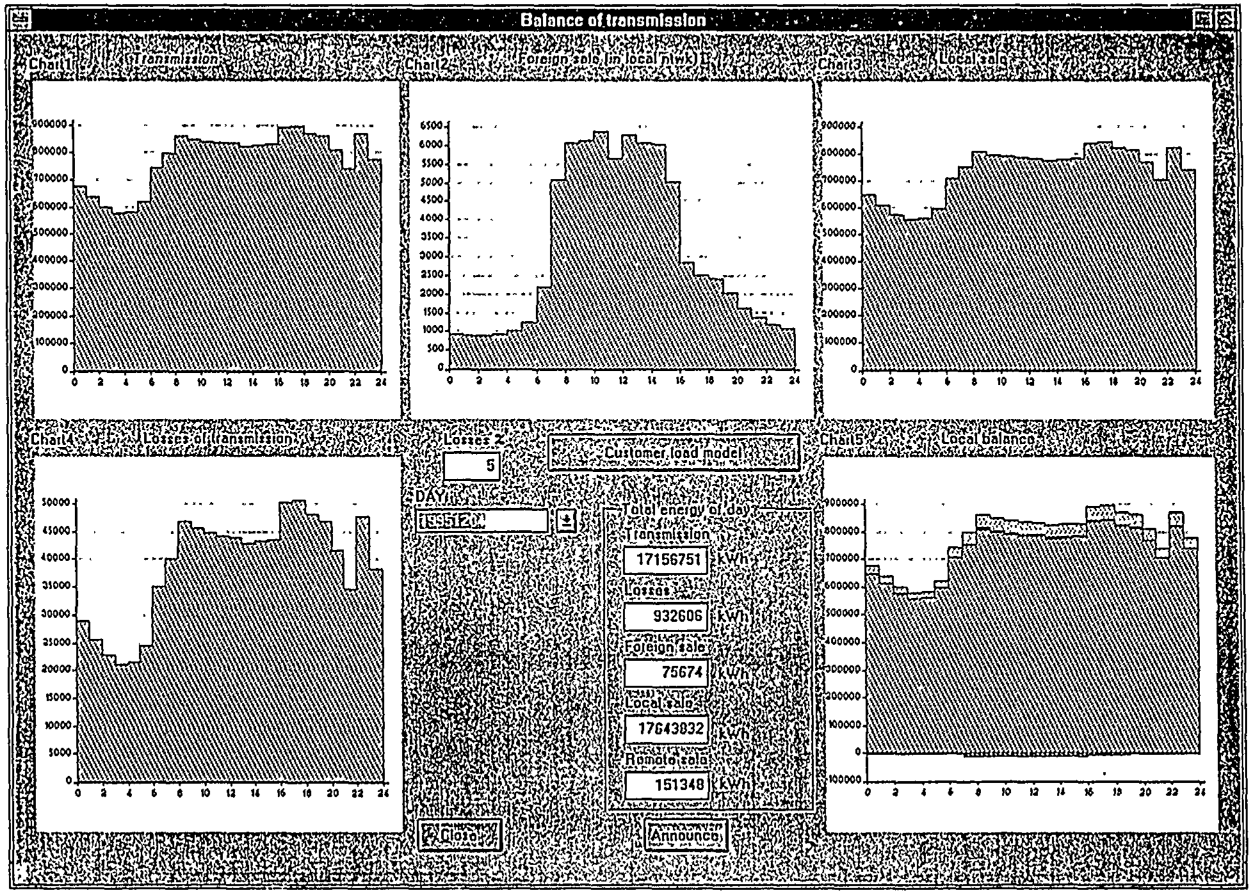

Fig. 36. An example of the graphical interface of the technical energy balance management function in the DEM system.

Table 10. 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.*

11.4 DEM - A DISTRIBUTION ENERGY MANAGEMENT SYSTEM

In this section, a computer prototype system for distribution energy management (DEM) in the free electricity market is presented. The basic functions of the DEM system are first considered. These are the processing of measurements and load models, and the on-line estimation of energy balances. Next, the functions needed for energy trade and energy management are studied. The main functions are listed in Table 9.

11.4.1 Functions

1. Electrical load estimation: Estimation of load flows in the distribution system is based on the combination of type users´ load models, statistical data, customer information and measurements. The module produces on a real-time basis the best possible estimate for the state of the medium voltage distribution network up to the secondary (MV/LV) substations. This function is mostly operated by the network company, who has access to all the measurements in its area, and who also monitors the network topology on a real-time basis. Here, the role of the trading company is to receive information from the network company.

2. Load forecast, short, medium, long term: This is a general purpose function, the task of which is to produce forecasts for the hourly demand of the utility, line, secondary substation or customer level. The techniques used include time series models and/or regression based type users´ load models. The inclusion of time series analysis is needed primarily for short span prediction, i.e. 24 hours expected hourly average demands. The longer time spans, up to a few years are handled based on the type users´ load models.

3. Technical energy balance estimate: This is an on-line estimate of the total power selling of the trading company. The function produces a history of hourly mean demands, which also can be used as the input data for the load forecast function, in order to produce an estimate for the future demand or sales. Essential for this function is the information received from the electrical load estimation run by the network company. The difficulty with this function is, that the trading company has to deal with a huge variety of information at different technical levels. Here the problem is solved so, that the information is first transformed into the form of load models. An example of the man-machine interface of the technical energy balance management in the DEM system is given in Figure 36.

4. Commercial energy balance management: In the de-regulated market, the sold power is settled only a few weeks after the corresponding day. The settlement is based on the energy balance computations of a third party. This data is then delivered to the counterparts of the business. This function manages the commercial energy balance in the electricity selling company, and also gives a feedback to the technical energy balance, in order to minimize the inaccuracies in the latter one.

5. Load metering handling for billing: This function collects and manages the metering data used for billing the distribution system customers. In the case of hourly measurements, load variation curves are also produced, which in turn can be used for the above functions.

6. Selling / buying agreement management: This function assists in designing selling and buying offers and also manages the various commercial documents needed for the trade of the electrical energy at the bulk level. Both short-term and long-term agreements are considered.

7. 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.

8. Electricity purchase optimization: Optimization of the electrical power purchase by long-term agreements and by scheduling their own generation capacity. As a result, this function gives a plan for generator commitment and estimated bulk purchase. Another result is the marginal electrical energy price, which in turn is used as input data for several other functions.

9. Pool price forecasting: This function produces forecasts for the electricity price in the spot market. The short term forecast (24 hours) is used for the spot trade optimization, whereas the long-term forecasts are used for long-term planning of power purchase and selling.

10. Short-term (spot) electricity trade optimization: This function assists in the optimization of the buying and selling of short-term power in the spot market. The optimization is based on the short term pool price forecast, marginal energy purchase price and the free capacity available.

11. Tariff design and retail sales planning: Design of the sales tariffs in the case of retail customers, includes marginal pricing, average cost effects in various customer classes and the analysis of market effects due to the price changes. It uses as input data the load estimates of various customer classes and the estimated marginal and average costs of power purchase.

12. Load control optimization, 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 optimization of their short-term and long-term use.

13. 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.

14. DSM impact verification: This function uses load models and the results of load estimation and energy balance calculation in order to verify the results of DSM actions of the two previous functions. The result is the updating of impact models.

15. DSM impact models, management of pseudo-load models used for the modelling of DSM actions: These models are of similar structure compared to the type users´ load models, primarily including hourly based average demand data.

11.4.2 Interfaces

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 10.

For the retail sales operation, the most important is the interface to the metering systems and to the substation telecontrol, or SCADA system. These interfaces produce the measurement based information, which mostly is necessary 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 incorporates many functions and data necessary also for the proper operation of the DEM-system. Among these are the metered demands which have been used as a basis for billing and the basic data of the customers, including for instance the customer type and the tariff chosen.

11.5 SUMMARY

In the de-regulated electricity market, the power trading companies have to face new problems. The biggest challenges are caused by the uncertainty in the load magnitudes. In order to minimize the risks in power purchase and also in retail sales, the power traders should have as reliable and accurate estimates for 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 the operation of Finnish utilities in the newly de-regulated power market.

12 DEVELOMENT OF METHODS FOR DSM AND DISTRIBUTION AUTOMATION PLANNING

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

12.1 THE AIM OF THE PROJECT

The interest of utilities and governmental agencies in DSM and IRP has increased during recent years also in Finland. From the governmental poit of view, the main reason for this has been concern about the environmental effects of electricity supply and consumption. Utilities are mainly interested in cost-reductions in electricity supply and distribution caused by DSM. Also improved service to customers due to DSM has increasing value to utilities.

The structure of the utility industry and electricity market has changed rapidly also in Finland. The network business remains a monopoly and it is separated from the electricity trade business. It means that the interest of the utilities in DSM is changing, the costs and benefits of DSM for different actors in the market are changing and there is not yet a clear understanding of how, why and which kind of DSM/IRP can work in the new situation.

In this project, the main target is to develop and assess methods for DSM and distribution automation planning from the utility´s point of view. The final goal is to integrate these methods for the strategic planning of electric utilities.

In practice, the project is divided into four main parts:

- The development and assessment of DSM/IRP planning methods and cost/benefit analysis as a part of international co-operation (IEA DSM Agreement: Annex IV, European Cost/Benefit analysis of DSM, EUBC, and Finnish SAVE-project started in 1995 in co-operation with SRC International and six electric utilities in Finland)
- Development of PC-based DSM planning and assessment tools at VTT
- Development of a decision support system of distribution network planning including DSM options at Tietosavo Oy and
- Integration of DSM planning and network planning tools in co-oparation with VTT Energy and Tietosavo Oy

12.2 DSM AND IRP PLANNING METHODS AND THEIR APPLICATIONS

12.2.1 Backgound

Demand-side management (DSM) is usually a utility or governmental activity 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 implement DSM are direct load control, innovative tariffs, different types of campaigns etc.

Integrated resource planning (IRP) is a planning process to consistently assess a variety of demand and supply side resources to meet customer energy service needs at the lowest, reasonable economic cost, subject to utility specific or govermental specific objectives. The key issue is the simultaneous assessment of both supply-side and demand-side resources on an equal basis.

Restructuring of the utility industry in Finland and inceased competition in the electricity market have had a dramatic influence on the DSM and IRP. Traditional IRP is almost impossible due to the conflicting interests of generation, network and supply companies and increased competition between different actors. Costs and benefits of DSM are divided among different companies, and different types of utilities are interested only in those activities which are beneficial to them.

On the other hand, the electric market act in Finland doesn't require that the distribution network business and supply business should be separted into different companies, separate book-keeping is enough. This gives possibilities to utility-based IRP where the utility includes both supply functions and monopoly network functions. However, also in this case it must be possible to divide the costs and benefits of DSM activities to different parts of the utility.

12.2.2 International co-operation

Quite a large amount of the work is needed to analyze the changing situation in utilities and in the market in order to get the right framework for the development of the planning methods. One part of this work was integrated into the work carried out in connection with the IEA DSM Agreement, Annex IV: "Planning methods for integrating DSM options into utilitry resource planning and governmental policy".

As a result of this work a general framework for analysis of DSM in different DSM actiivities was developed and reported. Also a large number of planning methods and software were analyzed. The general conclusion for Finnish conditions is that there are no directly applicable planning models for our conditions, and therefore we have to develop our own models. On the other hand, there are a large number of submodels which are also applicable in Finland.

The cost-benefit analysis of different types of DSM options can be carried out from the perspective of different actors. In the European Cost/Brenefit Analysis Project (EUBC) the qualitative and quantitive methods for analysis were developed from the point of view of different actors: generators, suppliers, network companies, customers, government, society. These methods were utilized in the PC-model developed by VTT as far as they were applicable to the Finnish situation.

12.2.3 Finnish case studies

At the end of the year 1995 a new SAVE project was started in Finland, where different types of DSM actions were implemented in six utilities in Finland. The cost-benefit analysis and assessment of different DSM-actions are based on the methods developed during this EDISON-project. The case studies are presented in Table 11.

12.3 PC-BASED TOOLS FOR ANALYSING AND ASSESSING DSM ACTIVITIES

12.3.1 Simulation of DSM impacts

As a part of the planning process of energy utilities the following questions need to be answered:
- How does DSM affect short term operation of the energy utility, and
- how does DSM affect investments of the energy utility in the long term?

A general approach to assess DSM options was defined within this project with the purpose to analyze typical DSM activities in Finnish circumstances and to help Finnish utilities outline their DSM policy.

A DSM activity list, a set of well defined DSM techniques is assumed. Detailed DSM facts are collected into the DSM impact library. In practise, there are a lot of different DSM options available, but technical knowledge of their influence varies. More research and many demonstration projects are still needed also in Finnish situation to gather more accurate measurements of DSM impact.

Table 11. Finnish case studies in the SAVE project.

	Type of the utility	Target group for DSM	Main motive for DSM	DSM activities	Type of cost-benefit analysis/utility IRP
Hämeen Sähkö Oy	Mainly rural. Share holding company owned by municipalities	Residential having direct resistance heating	Decrease the cost of electricity supply, load shifting to night time	Customer advice, TOU-tariffs, heat storages for domestic hot water production	C/B-analysis from the point of view of both the supply and the customer, evaluation of results
Kainuun Sähkö Oy	Both rural and city utility with CHP and district heating. Share holding company owned by municipalities	Residential having direct electric heating with fire places or ovens	Decrease the cost of electricity supply, load clipping	Financing services, increase the use of wood by information through two-way communication system	C/B-analysis from the point of view of both the supply and the customer, evaluation of results
Savon Voima Oy	Mainly rural. Share holding company owned by municipalities	Certain geographical area	To avoid network investment	Network and market analysis, selection of target groups and realization of selected DSM	C/B-analysis from the network point of view, utility IRP, evaluation of results
Tampereen kaupungin sähkölaitos	City utility having CHP and district heating. Utility is a part of the technical works of the city of Tampere	Public lighting	Decrease to energy cost of the large customer which is also the owner of the utility (city of Tampere)	Improving the efficiency of street lighting by modern lamps and control systems	C/B-analysis from the utility and customer point of view, utility IRP, evaluation of results
Vantaan Sähkölaitos Oy	Mainly city utility having CHP and district heating. Share holding company owned by the city of Vantaa	Large industrial and commercial customer	To retain customers in competitive market	Measurements and energy audits carried out by utility, proposals for improvements	C/B-analysis from the utility and customer point of view, utility IRP, evaluation of results
Vatajankosken Sähkö Oy	Mainly rural. Share holding company owned by municipalties	Residential customers	Improve customer service and decrease customer costs (owners of the utility)	Information, energy audits, proposals for improvements	C/B-analysis from the utility and customer point of view, evaluation of results

In theory DSM impact on the load shape form can be estimated, where the load shape is a function of time and consumer group. The most interesting data is the mean value of the end-use load and its deviation. This load shape form, multiplied by volume of its activity, can be subtracted directly from the total load, so that it acts like a pseudo consumer, which greatly reduces load, although the load increasing option is also possible. A PC-based load impact tool was developed based on the above assumptions.

12.3.2 Electricity supply optimization in the case of DSM

The energy utility aims to save operating costs by means of DSM. A simple and speedy method has been developed within this project to roughly estimate purchase cost reduction. It is based on the effect of separate purchase sources, and their energy costs; both are functions of time. This method is slightly more precise than the marginal cost method, where marginal cost is a given vector of time, because the amount of saving has an influence on the amount of cost reduction. Absolute total operational costs are also obtained by this method.

A more accurate method has also been investigated, and it is a linear model optimization method, which could be used as a simulation tool for annual operation. This DLP (Dynamic Linear Programming) based method makes, for an energy utility, an optimal load allocation for every hour in the year. VTT has developed an advanced algorithm for this kind of problem. It performs a decomposition, so that the entire problem can be solved piecewise, in this case sequentially, and the final dynamic solution will be produced iteratively. Energy storages like water reservoirs and heat storages are the dynamic components of the model.

Results from an optimization process are obtained on an hourly basis for a year. The results include variable costs of energy supply, the energy output from each production unit, the use of energy purchase or sale components, the use of each fuel type available, and marginal costs of each constraint of the DLP model, including marginal costs of total purchase.

12.4 DEVELOPMENT OF AN ENVIRONMENT FOR A DECISION SUPPORT SYSTEM IN POWER DISTRIBUTION SYSTEM PLANNING

12.4.1 Introduction

The circumstances in power distribution are changing in Finland. The competition in the energy market is beginning and more energy efficiency will be needed in the future. This requires planning methods and applications for the power distribution utilities. The Demand Side Management investment must be integrated with the conventional distribution system investment.

We are developing the methods in the EDISON-project. 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.

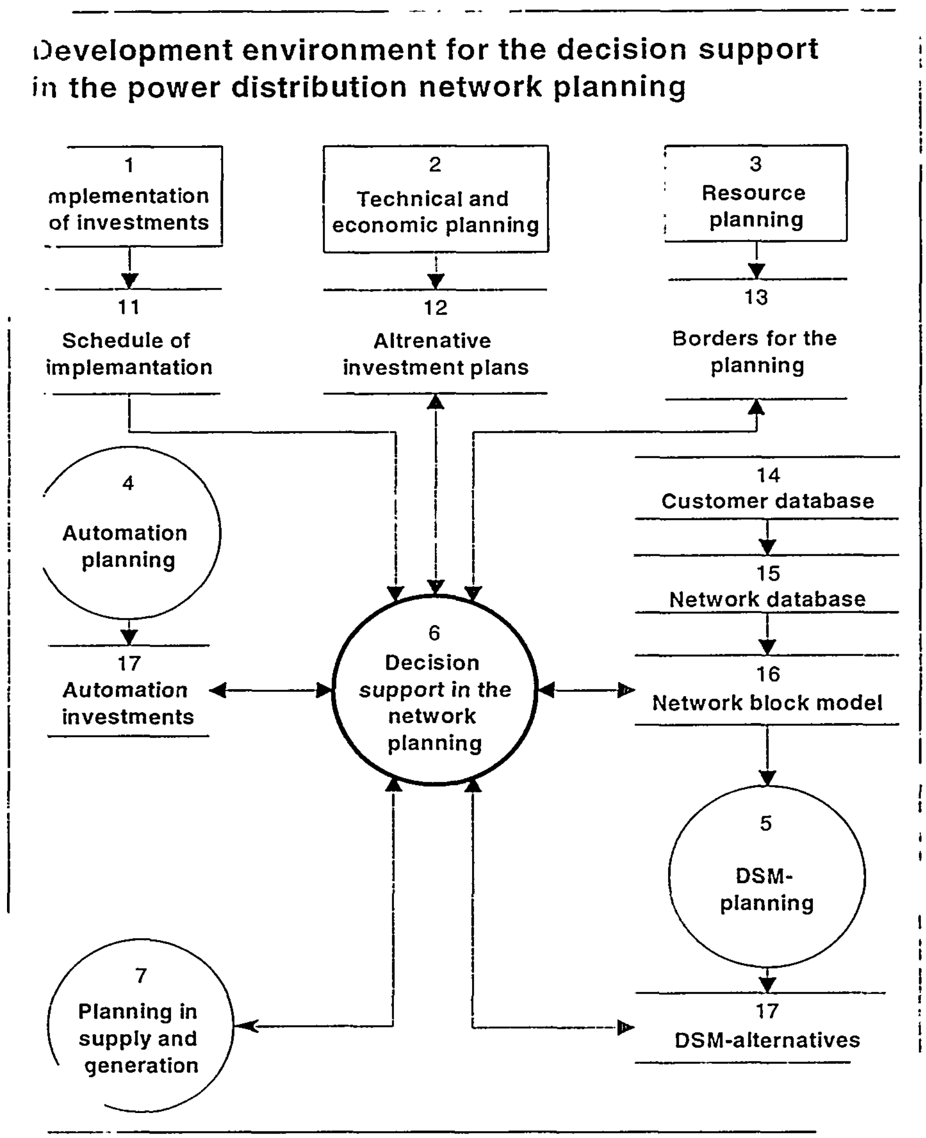

Fig.37. Basic connections between different parts in the planning process of a distribution company.

12.4.2 Objectives

The purpose of this part in the EDISON-project is to create an 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 Resource Planning in power distribution utilities.

On the other hand, the methods will be developed and applied for practical purposes in power distribution utilities.

12.4.3 Environment

Different databases and planning practices create the basic environment for the decision support. Figure 37 represents the basic connections in this setting. In the following the development work for different areas is briefly summarized.

Scheduled investment projects

Estimated and real costs with all classification data are collected in a database called Scheduled investment projects. This database has been updated in Pohjois-Karjalan Sähkö Oy for about two years.

From this database we have compiled an Access-database for different classification purposes. Using normal database operations the planner can see the real investment flow of the last years and an estimate 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. In the year 1995 we only collected the current investment into the database for later purposes.

Network block model

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 in order to include it in a network model.

In this environment we have designed the Network block model which first services the DSM-planning and the distribution network automation planning. The basis for this model is in reliability calculations. The network is divided into blocks by the breakers and disconnectors. The blocks form a network. The distribution network in the block is modeled as an equivalent network if needed. The load curves and the consumption of the customers are collected to the blocks. 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 which we can select the best combination of DSM and distribution system investments

A prototype of the network model and the network block model is programmed in C++ language and the first connections to the databases have been performed using an ODBC-interface. Formerly medium voltage network calculations, including reliability calculations, were programmed in this model.

For DSM-planning the calculation of the loads is performed for every hour of the year. So we can display, for example, the peak power of a certain point in a distribution network. From these displays we can see the worst times of the year as seen in Figure 38. From a different list we can see what kind of consumption there has been. This knowledge we can use when we deside where and for which consumption the DSM-efforts should be focused.

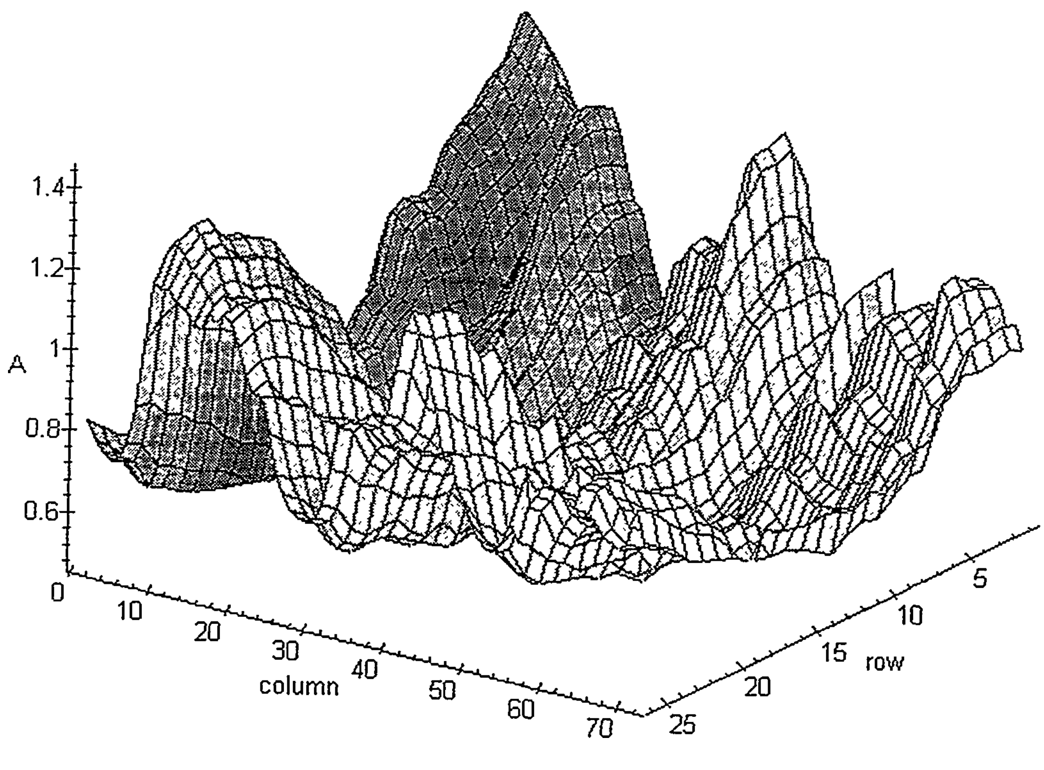

Fig. 38. Peak powers (A MW) in supply L0118 for weekday, Saturday and Sunday hours (column) in two week periodes (row) of the year.

DSM-planning

In Savon Voima Oy a DSM case-project is beginning (Table 11) whose purpose is to avoid network investment for a certain distribution area. This distribution area we have designed as the first test case for the Network block model. The results of this case-project, together with other DSM case-projects in Finnish power distribution companies, will focus on the development work of the models.

The first load curve formulating algorithm is adopted to the environment. The algorithm has been developed in the EDISON-project. A modified version of this algorithm will be applied in the network block model.

First we have defined an interface between power distribution network planning and DSM-planning (see point 12.5). 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 consuption should be moved or saved? Further we must estimate the amount of the investment, which should be avoided or postponed.

Within these limits DSM-planning tries to select the best combination of actions, which promote the needs of the distrbution 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 mean 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 to the network planning. The network will be calculated using these new load curve changes. This result is then the basis for investment in the power distribution network or we can define new goals for the DSM-planning and start the interaction again.

Automation planning

Profitability calculations for different distribution automation systems have been designed in the EDISON-project. The returns from the investment in automation have been programmed in the ACCESS-database model as seen in Figure 39. This model will be developed further in cooperation with the EDISON-project.

Profitability of automation investments — Version: MS2

	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

Record: of 7

Fig. 39. 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 block model will be suitable for use. Finally the profits from these investments will be compared with other investments profits

Further development

The previous models and prototypes create the basis for future 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 made to collect data from planning areas and balance the plans in the Integrated Resource Plan.

12.5 DSM ANALYSES FOR NETWORK PLANNING PURPOSES

DSM actions could be relevant options for network investment in some cases. When a network investment is considered, there will be some reasons, why the investment, or DSM, is needed.

The appropriate data is obtained from the network planning system. It includes load estimates for different sites and time points and similar main electrical quantities, like load flows and voltages etc. Load estimates are based on load curve information and the consumer classification system stored in the network data base and the customer data base.

Each consumer type has an index series, which gives relative hourly consumption rates for workdays, Saturdays and Sundays separately for every 2-week period in the year. This is a system commonly used earlier by the Association of Finnish Electric Utilities and currently by VTT. When a consumer type, the number of individual consumers and their total annual energy is known, an approximate hourly consumption rate in kWh is given for any hour in the year. The structure of the index series is presented in Figure 38.

The network investment planning system gives the main information for DSM planning to achieve expected load modifications (point 15 in Figure 37). At this point the DSM-planner starts the trial of different selections of DSM activities targeted to different groups of consumers in various magnitude scales. When a satisfactory solution is found, the results will be reported on the form of consumption index series representing DSM load modifications, and the scaling factors as annual energy savings. When a network planner has given the goals of DSM activities, a DSM planner figures out, which DSMs are the most profitable ones and how they should be implemented.

The next phase is to validate the DSM plan through the network planning system to make sure, that the effect is what it was intended to be. There might be some side effects, too. The planning circuit or some parts of it might be repeated sometimes to confirm all the desired effects.

DSM analysis gives some additional information needed in the decision making procedure, like

- influences within the economy on sales and distribution companies
- benefit / cost analysis for different perspectives.

The DSM analysis software development was completed in 1995 in the EDISON project (see section 12.3). It is written in C-language and it contains a DSM activity library. A PC compatible prototype software uses an ACCESS data base for storing utility based planning data and a user interface to modify data and perform DSM analyses. A load curve presentation tool is written in APL language. The main outputs are DSM-load curve index series and benefit / cost analyses reports. The future development will include enlarging the DSM activity data library.

13 COMMUNICATIONS TECHNOLOGIES FOR DEMAND SIDE MANAGEMENT, DSM, AND EUROPEAN UTILITY COMMUNICATIONS ARCHITECTURE, EurUCA

Pentti Uuspää, VTT Energy

13.1 SCOPE

The scope of this research is data communications for electric utilities.

Demand Side Management (DSM) calls for communication between the Electric Utility and the Customer. The communication capacity needed will depend on the functions that are chosen for DSM, and on the number of customers. Some functions may be handled with one-way communications, some functions require two-way communication.

Utility Communication Architecture looks for 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.

13.2 CUSTOMER/UTILITY FUNCTIONAL NEEDS AND COMMUNICATION TECHNOLOGIES

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, and then combining the responses obtained.

There are about one hundred utilities in Finland in 1996. 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 considering size, location, and customer mix; and serving both urban and 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 shall consider all of the potential communications needs, and to check how these could be handled by the communications system being planned.

Some of the electric utilities are actually energy utilities with other products and services besides electricity. Communication needs for the other services should also be assessed.

Combining the data of the communication needs of electric utilities with those of other utilities such as gas and water utilities, has also been considered.

The communication functions of an electric utility may also be combined with a selection of other telecommunications services for households.

The selection of communication services could be offered by the utility or by a company controlled by the electric utility. A very natural choice can an outside telecommunications company acting as a partner with the electric utility.

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

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

When the functional needs are known, the data rates required to create these functions can be estimated. Data rate requirements can be compared with the capacities of the channels using various communication technologies. For the several possible communication technologies, the feasibility of implementing a selection of DSM functions has been investigated.

Penetration of a function is one more variable parameter to be considered. Penetration means the percentage, from zero to hundred, that describes how large a fraction has been implemented in the range from a predefined minimum to maximum. Here maximum refers to the ultimate number of users of a given function. The maximum percentage may be chosen to reflect the estimated willingness of the users to choose a given service. One may vary the percentage value of penetration stepwise, 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, and Radio. Also combinations of these technologies are possible (Figure 40). Hierarchically, one can divide the communication task into two or even more layers, and choose a technology for each layer independently. Within one layer also, reasons may arise for adopting several technologies that carry part of the data communication load in a parallel fashion.

Communication systems may be designed for one-way or two-way communication. Some of the more advanced DSM functions require two way communication.

13.4 STANDARDS

There are communication standards specifically for electric power applications. There are also more generally used communication standards, which may be valuable for 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 standards proposals. Formally, international standards are confirmed by international standard bodies. The International Electrotechnical Commission (IEC) is important in the electrotechnical field. Also, the European standardization activities within CEN and CENELEC have been 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.

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 methods research project.

13.5 PRIORITIES FOR FUTURE RESEARCH

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

There are numerous new technologies within communications that have emerged recently. The ones that are likely to survive, are becoming more common in many application areas. Thus Electric Utilities are likely to utilize the communications media that will reach the customers, and especially the domestic households, in the future.

13.6 TECHNICAL EVALUATION AND COSTING MODEL

A model that allows for examining the cost of communications systems for an electric power company and demand side management purposes, is being developed. 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.

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

13.7 EurUCA

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 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. The Dutch distribution companies are quite large, and their number is fairly small.

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.

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 (Figure 41).

The second phase of the EurUCA project includes demonstrations of the utility communication systems. The intention is to use existing systems, together with manufacturers, to demonstrate compatibility and integration of systems. A selected set of functions is to be chosen for the demonstration. The demonstration is to be carried out in several phases.

13.8 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) and the work was completed in 1991.

The major 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 pools, 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, the OSI-model has been chosen as a basis.
Standards which cannot work within an OSI framework cannot be incorporated into the UCA.

Note: This research is the Finnish part of two international research projects:

One of the projects concerns Demand Side Management, with ten participating countries under an International Energy Agency (IEA) Implementing Agreement on Communications Technologies for Demand Side Management. 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.

The other project is the EurUCA project, with participants from Finland, France, the Netherlands, and Sweden. The EurUCA project is managed by KEMA in Arnhem, the Netherlands.

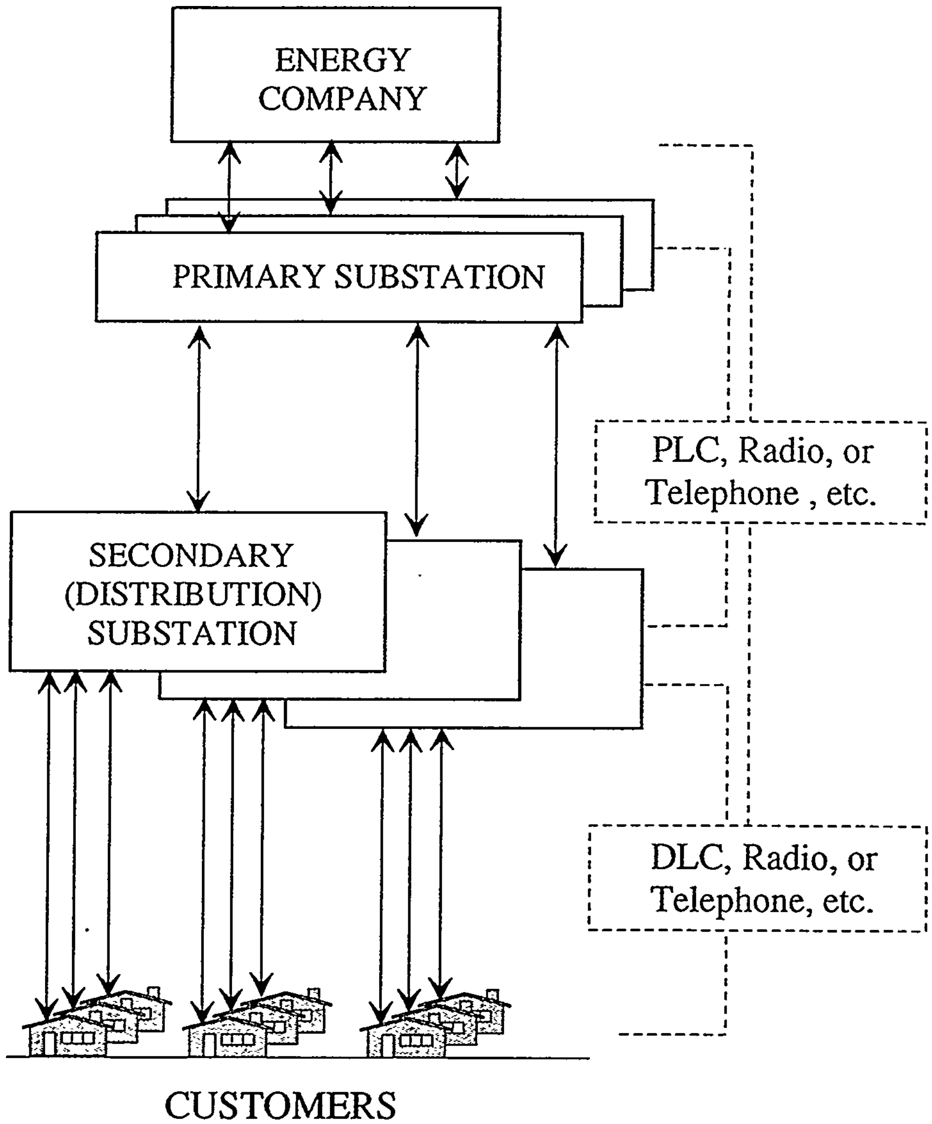

Fig. 40. Communication systems for Demand Side Management may consist of a hierarchical structure. Communication between the Primary Substation and the Secondary Substation can use one technology, while communication between the Secondary Substation and the Customer may use the same technology or other technologies.

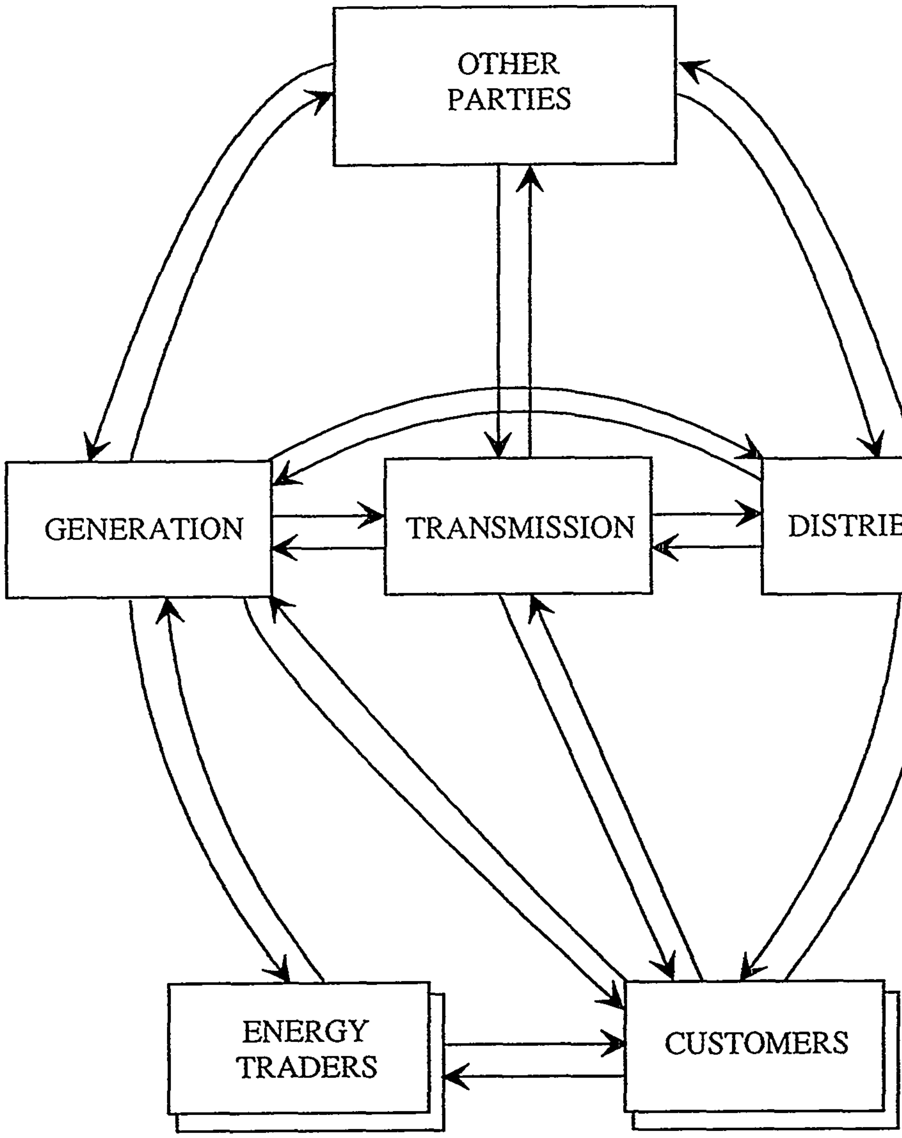

Fig. 41. European Utility Communications Architecture (EurUCA) project models the locations, business processes, and data flows for an Electric Utility. The model is hierarchical in the sense that the items "Production", "Transmission", and "Distribution" have been divided into their components as well.

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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

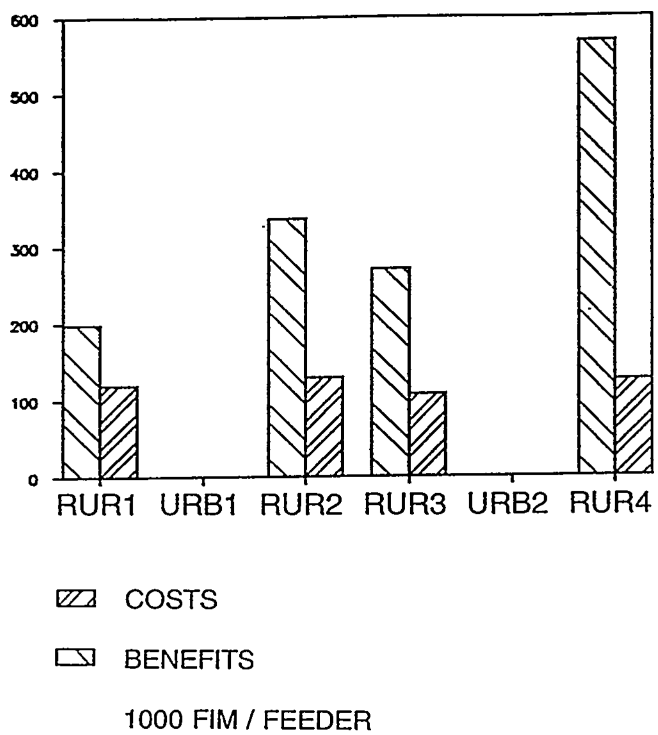

Fig. 1. Line switch remote control

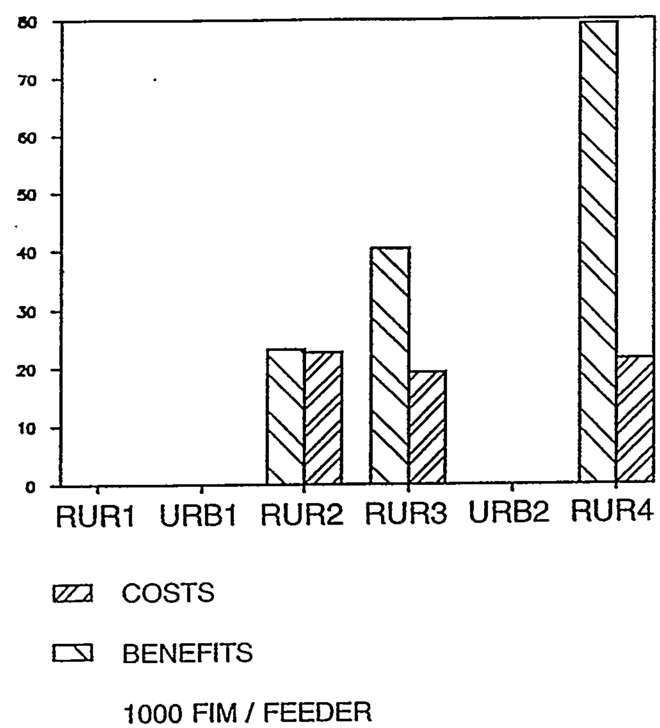

Fig. 2. Fault indicators at line switches.

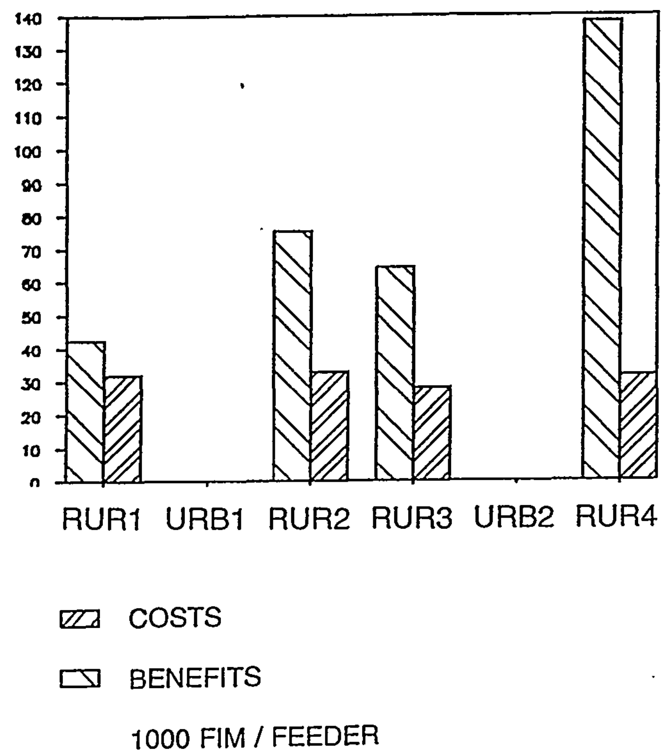

Fig. 3. Fault indicator stations.

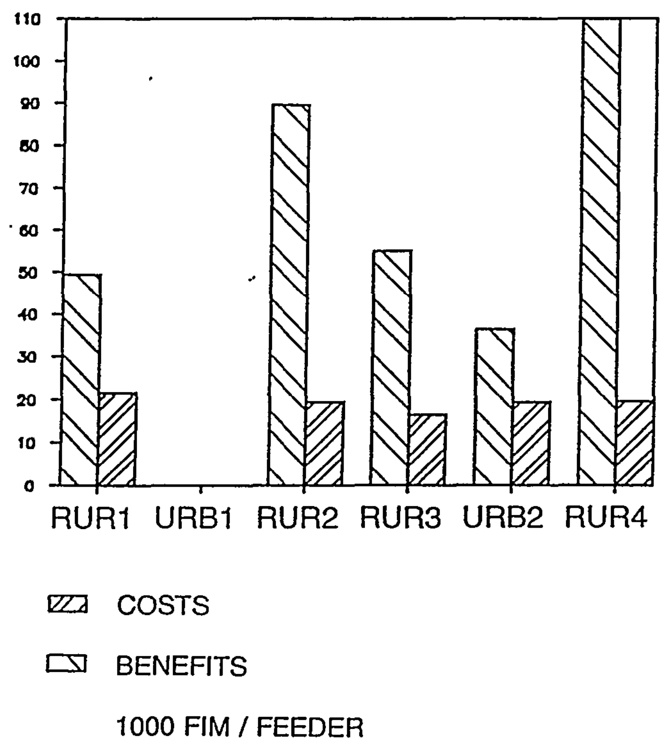

Fig. 4. Computational fault location.

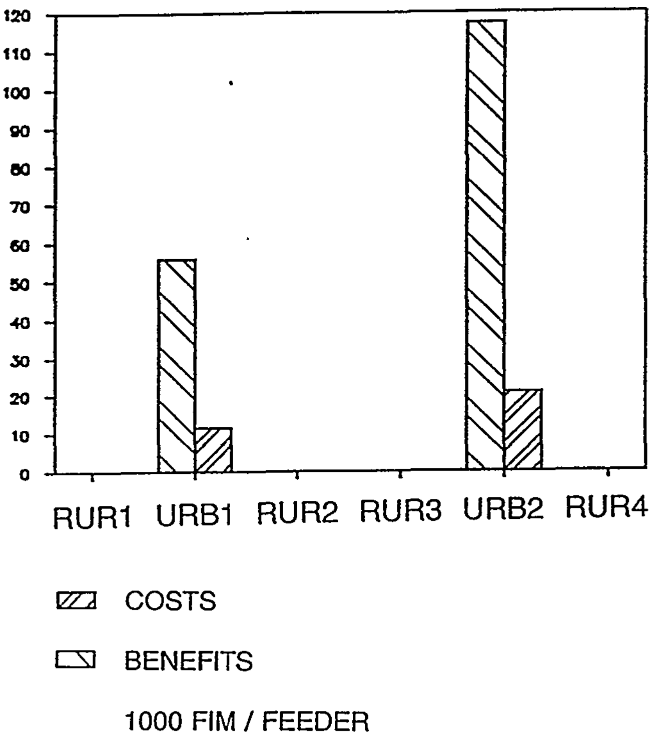

Fig. 5. Fault indicator remote reading at secondary substations.

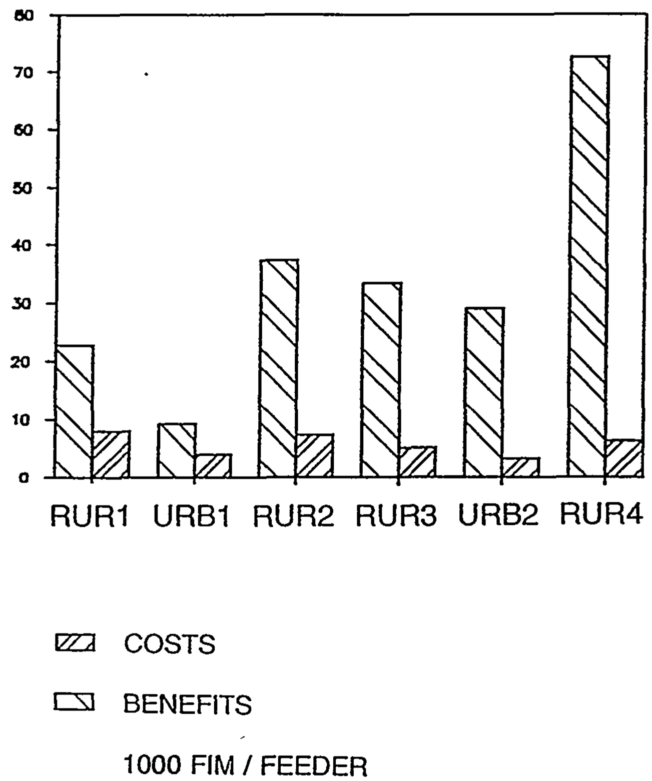

Fig. 6. High resistance fault indication.

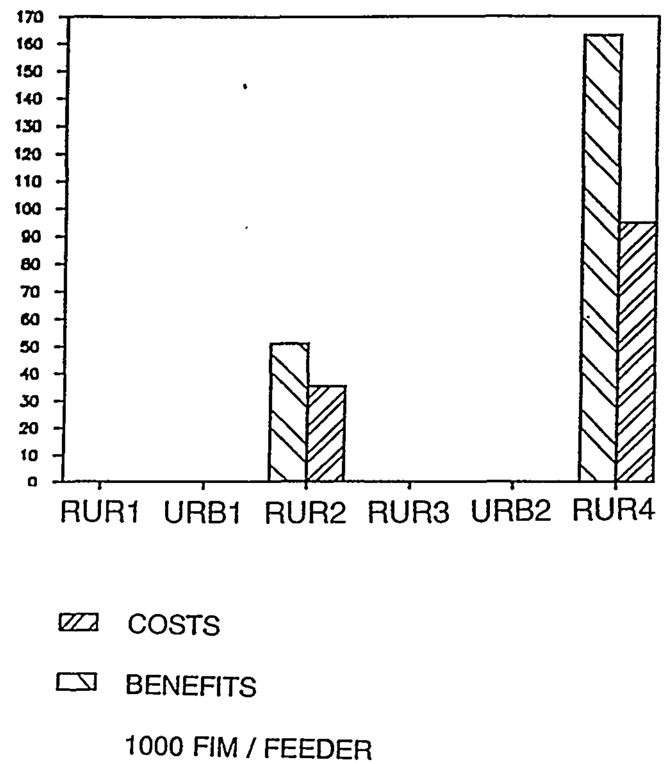

Fig. 7. Reactive power compensation at MV line locations.

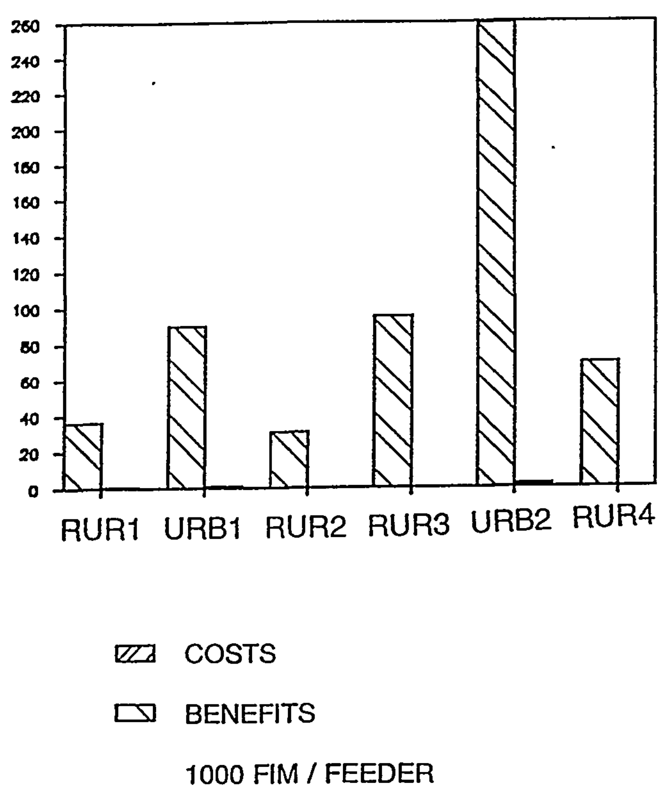

Fig. 8. Voltage regulation.

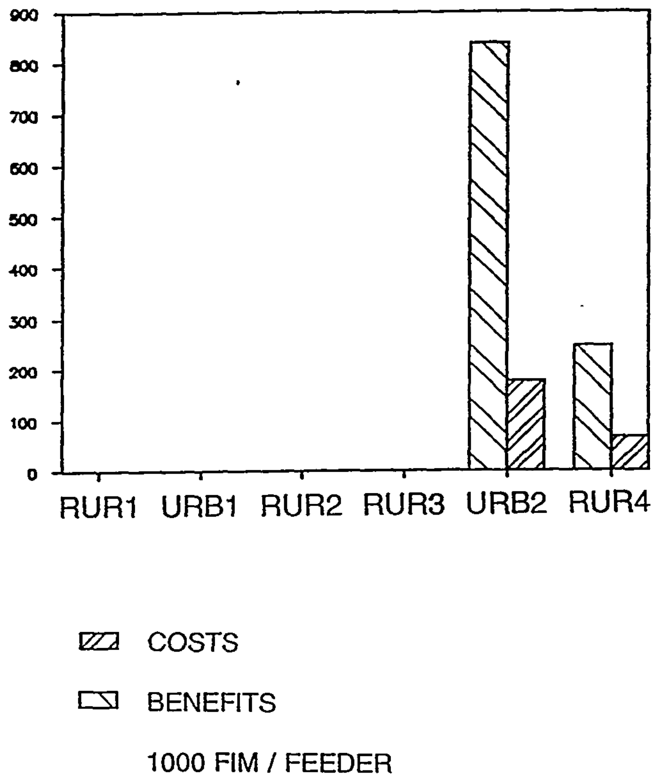

Fig. 9. Direct load control.

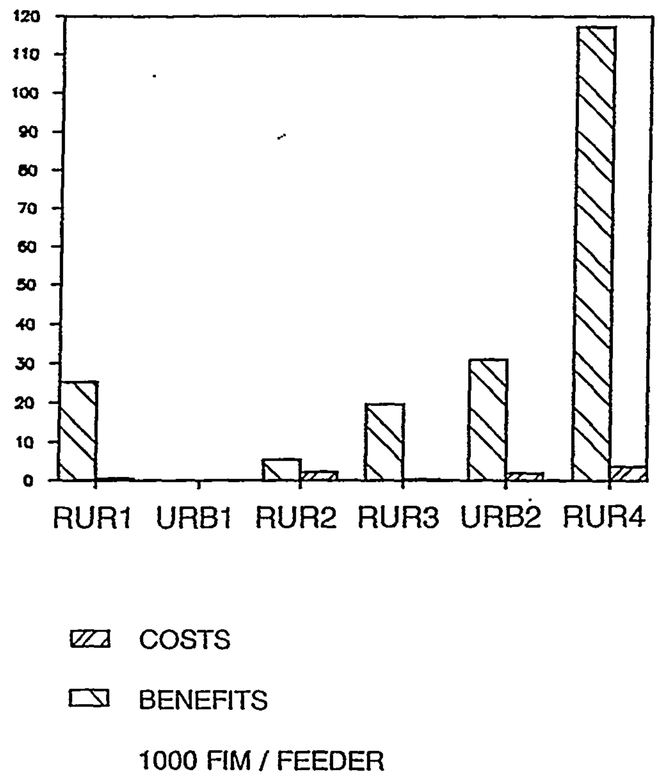

Fig. 10. Load estimation / component load monitoring.

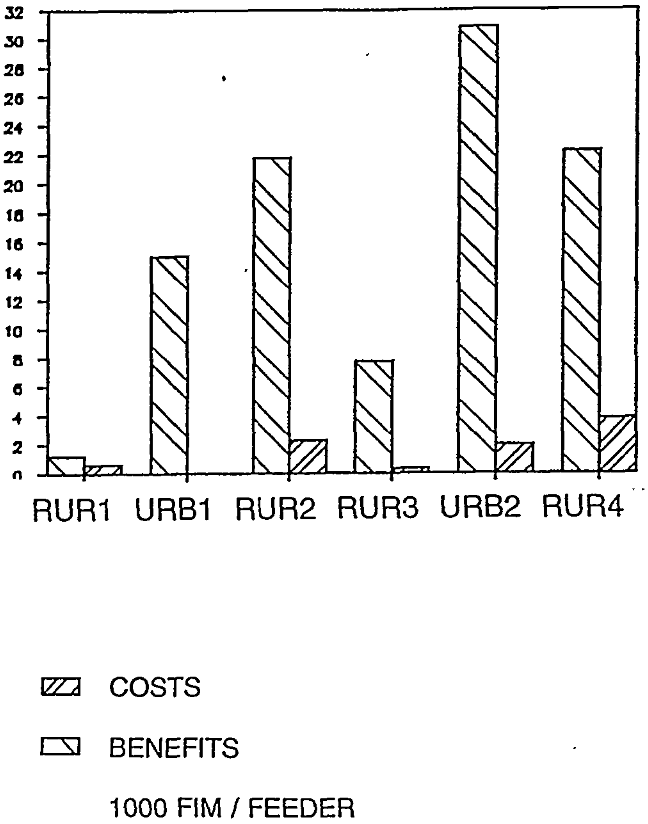

Fig. 11. Switching planning.

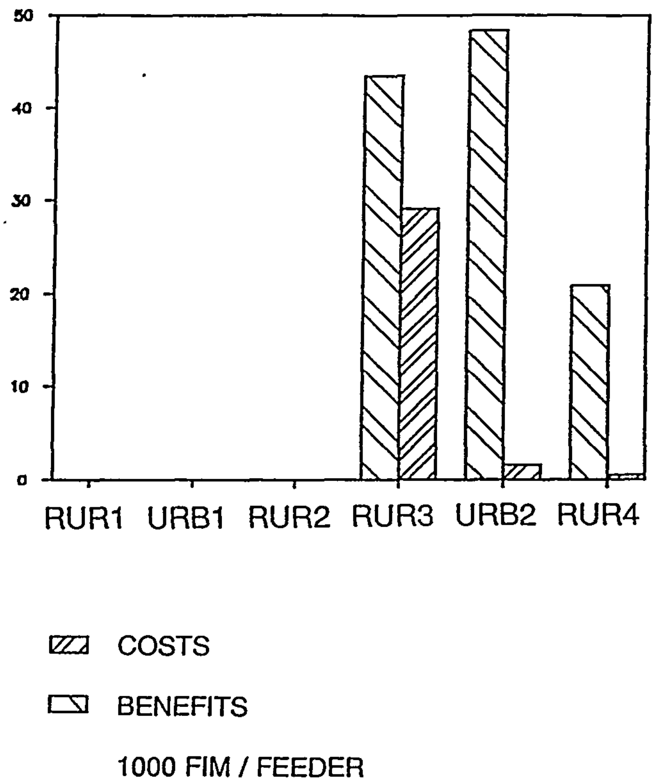

Fig. 12. Remote metering / dynamic tariff application.

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EDISON – research programme on electricity distribution automation 1993–1997

Interim report 1995

Abstract

The report comprises a symmary of the results of the first three years of the research programme EDISON on distribution automation in Finnish electrical utilities. The five year research programme (1993–1997) is conducted under the leadership of VTT Energy, in cooperation with universities, distribution companies and the manufacturing industry. The main part of funding is from the Technology Development Centre (Tekes) and from manufacturing companies.

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

The final aim is to demonstrate the automation functions and systems of the scheme in real distribution systems. The results of thirteen projects are now given. These results should be considered intermediate, since most projects will be continued in 1996.

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