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DEVELOPMENT NEEDS IN AUTOMATIC FAULT LOCATION, ISOLATION AND SUPPLY RESTORATION OF MICROSCADA PRO DMS600

Faculty of Engineering and Natural Sciences
Master of Science Thesis
November 2019

ABSTRACT

Jussi-Pekka Lalli: Development Needs in Automatic Fault Location, Isolation and Supply Restoration of MicroSCADA Pro DMS600
Master of Science Thesis
Tampere University
Degree Programme in Electrical Engineering
November 2019

Tightened reliability requirements for the electricity distribution are causing distribution system operators to improve the quality of supply by renovating the network. To achieve a weather-proof distribution network by the end of year 2028, major investments must be made by means of replacing overhead lines with cables and increasing the level of automation in the network. Since the renovation process is rather slow and expensive, DSOs must obtain cost savings in distribution network operation by utilizing existing network automation more efficiently. One of the main solutions is to automatize the fault management and thereby reduce outage duration experienced by the customer.

Traditional fault management comprises the co-operation of the network control center and field crews working along the distribution network. An increasing amount of network automation, such as remote-controlled disconnectors, sectionalizing reclosers and fault detectors, is improving the response time of medium network faults when the operator can isolate the fault remotely from the control center. However, multiple simultaneous faults in major electricity disruption can cause personnel of the control center to be overburdened with fault handling and dispatching field crews. Therefore, automatic Fault Location, Isolation, and supply Restoration (FLIR) functionality is considered as a beneficial tool to assist the network operator. While the FLIR performs the first steps of fault management, operator is freed to conduct the operation of field crews repairing failures.

MicroSCADA Pro is a product family for electricity distribution control and supervisory by ABB. The current version of MicroSCADA Pro DMS600 4.5 already includes functionality for automatic fault isolation and supply restoration, but it is not used by any DSOs due to functional imperfections. The current fault detection, isolation and supply restoration (FDIR) functionality requires an exact fault location inferred by fault current measurements or fault indicator operations and therefore, it can rarely operate due to lack of initial data. To achieve an efficient operation, a trial switching sequence must be introduced as part of the existing functionality. The method of trial switching is normally used by the operator when fault cannot be located according to measurements and indications. A basic principle of the trial switchings is to divide faulty feeder into minor sections and close the substation circuit breaker against the suspected fault. This is continued until the circuit breaker trips and the fault has been located and isolated into a single disconnector zone.

The research for this thesis was carried out by interviews for Finnish DSOs to gather requirements and restrictions for the FLIR functionality. The main objective of the interview process was to familiarize the fault management process of a network control center operator, so as human-like operation of the FLIR could be obtained. Interviews gathered the most important development needs and possible restrictions to ensure the most fluent operation between automation and the network control center operators. For example, automation may not be wanted to restore supply from adjacent feeders during major disturbance, since multiple fault can occur and cause also backup feeder to trip and increase the faulty area. Automatic functionality should not also disturb the operation of network control center, and thus separate fault handling areas should be determined for FLIR to operate.

Keywords: Automatic fault management, FLIR, Fault Location Isolation and supply Restoration, SCADA, Distribution Management System, MicroSCADA Pro

The originality of this thesis has been checked using the Turnitin OriginalityCheck service.

TIIVISTELMÄ

Jussi-Pekka Lalli: Automaattisen vianerotuksen ja jakelunpalautuksen kehittämisvaatimukset MicroSCADA Pro DMS600 -järjestelmässä
Diplomityö
Tampereen yliopisto
Sähkötekniikan DI-ohjelma
Marraskuu 2019

Tiukentuneet käyttövarmuusvaatimukset sähkönjakeluverkoissa aiheuttavat mittavia investointeja sähköverkonhaltijalle. Saavuttaakseen Sähkömarkkinalain määrittämän säävarman sähkönjakeluverkon vuoden 2028 loppuun mennessä, jakeluverkkoa on vahvistettava kaapeloimalla tai siirtämällä johto-osuuksia esimerkiksi tien varsille sekä lisäämällä sähköverkon automaatioastetta. Edellä mainitut toimenpiteet ovat kuitenkin kalliita ja hitaita toimenpiteitä, joten säästöjä on saavutettava muun muassa keskeytyskustannuksista olemassa olevan automaation tehokkaammalla hyödyntämisellä. Automaattisella vianhallinnalla voidaan pienentää keskeytyksestä aiheutuvia kustannuksia sekä työvoimakustannuksia.

Vianhallinta on tärkeä osa sähköverkon käyttötoimintaa. Tiukentuvat toimitusvarmuusvaatimukset vaativat sujuvan vianhallintaprosessin erityisesti haja-asutusalueella toimivalle jakeluverkkoyhtiölle, jonka johtolähdöt ovat usein pitkiä ja alttiita sään vaikutuksille. Vianhallinta hoidetaan käyttökeskuksessa operaattorien toimesta kauko-ohjattavilla kytkinlaitteilla sekä ohjaamalla työryhmiä joko erottamaan vika käsikäyttöisellä kytkinlaitteella tai korjaamaan jo paikannettu ja erotettu vika. Keskeiset järjestelmät käyttökeskuksen toiminnan kannalta ovat käytönvalvonta- (SCADA) sekä käytöntukijärjestelmä (DMS), jotka tarjoavat reaaliaikaista tietoa verkon tilasta ja hälytyksistä. Jakeluverkon automaatiota sekä älykkäitä järjestelmiä hyödyntämällä voidaan toteuttaa itsenäisesti ohjautuvia toiminnollisuuksia, joista yhtenä esimerkkinä on automaattinen vianpaikannus, vianerotus ja jakelunpalautus (FLIR). Suurimmat hyödyt FLIR:n käytöstä saadaan tilanteissa, joissa verkon alueella on useita samanaikaisia vikatilanteita tai vika tapahtuu yöaikaan ja käyttökeskus on miehittämätön.

MicroSCADA Pro on ABB:n tuoteperhe, joka käsittää ohjelmistot käytönvalvontaan, käytöntukeen sekä verkkotiedon ylläpitämiseen. DMS600-käytöntukijärjestelmän nykyinen versio 4.5 sisältää FLIR-toiminnallisuuden, joka ei kuitenkaan tämän työn kirjoittamishetkellä ole käytössä yhdelläkään verkkoyhtiöllä toiminnallisten puutteiden takia. Tämän hetkinen toteutus vaatii tarkan vikapaikan, joka perustuu laskentaan joko vikavirta-, vikaimpedanssi- tai vikaetäisyystiedon ja havahtuneiden vikaindikaattorien perusteella. Tämän takia nykytoiminnallisuudella ei voida toimia esimerkiksi maasulun tapauksessa, sillä vikavirta on liian pieni laskennalliseen määritykseen. Usein ongelmaksi muodostuvat myös epätarkat tai puuttuvat vikavirran arvot sekä vikaindikaattorien vähäinen määrä jakeluverkoissa. Nykytoteutuksen FLIR pystyy hoitamaan vain yhden vian kerrallaan, mikä edelleen vähentää ominaisuuden hyödynnettävyyttä.

Työn aikana haastateltiin suomalaisia sähköverkkoyhtiöitä kartoittaen, mitkä ovat vaatimukset FLIR:n tehokkaalle toiminnalle. Haastattelujen tarkoituksena oli kuvata mahdollisimman tarkasti operaattorin suorittama vianerotus ja jakelunpalautus -prosessi, jota voidaan myöhemmin hyödyntää määritettäessä automaattitoimintoa mahdollisimman lähelle valvomohenkilökunnan mukaista toimintaa. Tarkoituksena oli myös selvittää mahdolliset rajaavat tekijät automaattiselle toiminnalle. Esimerkiksi jakelunpalautustoiminto täytyy voida kytkeä pois päältä suurhäiriötilanteessa, jossa todennäköisyys vikojen esiintymiseen ensimmäisen vikapaikan takaisella lähtöosuudella on suuri. Tällöin varayhteyden käyttäminen saattaa aiheuttaa keskeytyksen myös varayhteyslähdöllä. Automaattinen toiminto ei saa myöskään häiritä operaattorin toimintaa, joten on pystyttävä määrittämään rajattu alue, jossa FLIR operoi. Toimintarajoiksi voidaan määrittää laaja vianhallinta-alue, sähköasema, lähtö tai joukko toimilaitteita.

Avainsanat: FLIR, automaattinen vianpaikannus, vianerotus, jakelunpalautus, SCADA, DMS, vianhallinta, jakeluverkon toimitusvarmuus, käytöntukijärjestelmä, MicroSCADA Pro

PREFACE

This Master of Science Thesis was written for ABB Oy Power Grids at Hervanta Tampere. The examiner of this thesis was Professor Pertti Järventausta, who I would like to thank for the comprehensive feedback and ideas during the writing process. I would also like to thank for my thesis instructor M.Sc Ilkka Nikander for his excellent guidance during the writing process and contribution in DSO interviews. I would like to thank my colleagues at ABB Tampere Office for providing support and ideas during this never-ending thesis project.

This thesis would have not been possible without the contribution of DSO representatives: Sami Viiliäinen, Timo Kiiski, Janne Puustinen and Pekka Pennanen from Savon Voima Verkko Oy, Jari Moilanen from Kajave Oy and Juha Koivula, Arttu Ahonen and Timo Rentto from Koilis-Satakunnan Sähkö Oy. Thank you all for the interesting conversations and helpful information about distribution network operation and fault management.

Finally, I want to thank my family and friends for supporting me, not only during my studies, but also during my entire life!

Tampere, 20 November 2019

Jussi-Pekka Lalli

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LIST OF SYMBOLS AND ABBREVIATIONS

AI	Artificial Intelligence
AMR	Automatic Meter Reading
AMI	Advanced Metering Infrastructure
ANM	Active Network Management
ANN	Artificial Neural Network
API	Application Programming Interface
ASAI	Average Service Availability Index
CAIFI	Customer Average Interruption Frequency Index
CELID	Customers Experiencing Long Interruption Durations
CIM	Common Information Model
CIS	Customer information system
DAR	Delayed Auto-Reclosing
DA	Distribution Automation
DER	Distributed Energy Resources
DG	Distributed Generation
DLC	Distribution Line Carrier
DMS	Distribution Management System
DMS600	ABB MircoSCADA Pro DMS600
DMS600 NE	ABB MicroSCADA Pro DMS600 Network Editor
DMS600 SA	DMS600 Server Application
DMS600 WS	ABB MicroSCADA Pro DMS600 Workstation
DSO	Distribution System Operator
ELCOM	Electricity Utilities Communications
FDIR	Fault Detection, Isolation and supply Restoration
FLIR	Fault Location, Isolation and supply Restoration
GIS	Geographical Information System
GSM	Global System for Mobile Communications
GUI	Graphical User Interface
HMI	Human-Machine Interface
HV	High Voltage
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IT	Information Technology
KAH	Keskeytyksestä Aiheutunut Haitta (eng. Regulatory Outage Cost)
KSAT	Koilis-satakunnan Sähkö Oy
LAN	Local Area Network
LOM	Loss of Mains
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Day
MV	Medium Voltage
NCC	Network Control Center
NIS	Network Information System

OHL	Overhead Line
OPC	OLE for Process Control
PG	Tieto Power Grid Network Information System
PSAU	Primary Substation Automation Unit
RAR	Rapid Auto-Reclosing
RCD	Remote-Controllable Disconnector
RNO	Regional Network Operator
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCIL	Supervisory Control Implementation Language
SMS	Short Message Service
SSAU	Secondary Substation Automation Unit
SVV	Savon Voima Verkko Oy
SQL	Structured Query Language
SYS600	ABB MicroSCADA Pro SYS600
TAM	Telephone Answering Machine
TCP/IP	Transmission Control Protocol / Internet Protocol
UI	User Interface
UML	Unified Modeling Language
UPS	Uninterrupted Power Supply
XML	Extensible Markup Language

1. INTRODUCTION

Reliable distribution of electricity is the backbone of modern society. After several severe major electricity disruptions caused by extreme weather conditions, authorities have taken actions to improve the electricity distribution reliability. The current version of Finnish Electricity Market Act, published in year 2013, states that distribution system operator (DSO) must ensure a weatherproof electricity distribution network by the end of year 2028. Therefore, major investments must be made by means of replacing overhead lines with cables and improving the distribution automation. These investments are expensive and time consuming, so DSOs must obtain cost savings in the distribution network operation. According to the Distribution Network 2030 vision, requirements for the future state-of-the-art distribution network are [1]:

- High reliability distribution not prone to severe weather conditions
- Cost effective operation with less maintenance and human labor
- Environmental aspects are considered carefully
- Flexible distribution system to enable the penetration of distributed generation

Fault management is one of the key tasks of a distribution system operator. According to interruption statistics of the Council of European Energy Regulators, average of 70 to 80 percent of the outages in the European countries are caused by medium voltage (MV) network failures. [2] Therefore, besides traditional reinforcements of the MV network, DSOs are seeking opportunities to utilize existing network automation in fault management more efficiently. With remote-controlled switching devices, fault indicators and more sophisticated microcontroller-based protection relays, it is possible to automatize the fault detection, location and isolation process using local automation or utilizing advanced algorithms of a distribution management system (DMS).

The main objective for automatic Fault Location, Isolation and supply Restoration (FLIR) is to reduce outage costs and support the fault management process of the network control center especially in major disturbance situations and during nighttime. In a major disturbance situation, multiple simultaneous faults are occurring at the same time resulting control center operators to be overburdened with fault handling and managing field crews operating all over the distribution network. Thus, operating personnel can maintain better awareness of the overall situation and control the workflow more efficiently. Other potential benefits of the FLIR functionality can be achieved in un-manned network control centers during nighttime. If fault is occurring at night, automation can shorten the time of fault isolation and let the remote-working operator to continue handling the fault.

Motivation for this thesis was to research development needs for the FLIR functionality of ABB MicroSCADA Pro DMS600 distribution management system. There is already existing functionality available, but according to customer, it is not feasible enough to be used in daily actions. Current fault isolation and restoration feature is dependent on the exact location of the fault by fault current measurements or fault indicator operations. Fault current measurement is not always available, or fault distance calculation can indicate several suspected fault locations due to branched feeder topologies. Also, current fault indicator technology is discovered to be unreliable and thus they are rarely available. Fault cannot usually be located and therefore the algorithm is stopped leaving operator to handle the fault by hand.

The development needs for the FLIR functionality were gathered by interviews for three Finnish distribution operators: Savon Voima Verkko Oy, Kajave Oy, and Koilis-Satakunnan Sähkö Oy. The main objective of the study was to acquire knowledge of the fault isolation and supply restoration process carried out by the network control center operator and find key functionalities or restrictions for the FLIR application. Study was carried out with semi-structured interviews, which included open questionnaire sent for the DSO representatives in advance. The semi-structured interview method was selected to get the most comprehensive view and new ideas for the fault management functions. Interview also included methods for improving the distribution reliability and expectations of the benefits of the automatic functionalities. After the interview process, development ideas were presented, and additional information was gathered in the FLIR workshop during MicroSCADA Pro User Event.

The first part of this thesis consists of a literature review describing the Finnish distribution system along with a concept of distribution automation and regulation methods according to the fault management. General fault management is introduced from the network control center point of view, and the concept is supplemented with automatic functionalities. Also, benefits and challenges of currently increasing distributed energy resources are described briefly. MicroSCADA Pro product family is introduced focusing on the fault management functionalities of the DMS600 Workstation. The second part of this thesis comprises the most important features for the FLIR according to the DSO interviews. Development needs are summarized in a functional requirements document, and proposed features are analyzed according to the literature review and existing features of DMS600 to support the implementation of the FLIR functionality.

2. DISTRIBUTION AUTOMATION

The concept of distribution automation (DA) consists of an entity of devices used to control, plan, and monitor the distribution network remotely or automatically. Automation improves the reliability and usability of the distribution network and decreases the operational costs. Distribution automation provides the possibility to achieve automatic functionalities, such as automatic fault management and automatic voltage control. [3] Since the main objective of the thesis is to represent automatic fault handling methods, introduction to the DA concept is necessary. The comprehensive distribution automation concept can be presented with a hierarchical structure from a distribution company to a customer level, as illustrated in the Figure 1.

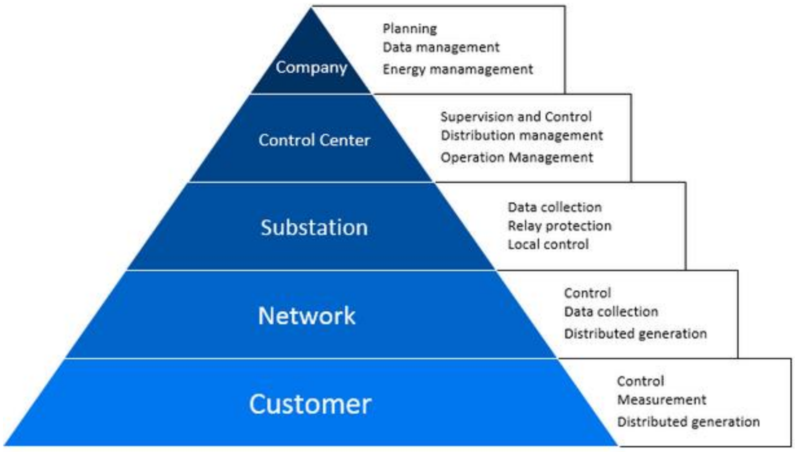

Figure 1. *The hierarchy of distribution automation adapted from [3]*

Each of the automation levels has different tasks and functions. Company level functions are focused on the administration and utilization of the information provided by various information systems, such as NIS, CIS, DMS, and SCADA. The main tasks at company level are e.g. management of network information and customer information databases, switching planning for maintenance outages, and planning of backup connections. The network control center (NCC) level automation is based on utilization of DMS and SCADA systems to monitor and control the distribution system in real time. In the outage situation, planning and switching actions as well as customer service and field crew management are carried out by the operational personnel of the NCC. Substation level is comprised of controlling the switching devices, operation of protection relays, and various types of measurements. Substation automation also includes e.g. control of the compensation devices and the primary transformer tap changers. Substation may also have an option of using SCADA locally if remote use from NCC is not available. Network automation includes the operation of remote-controlled switching devices, fault indicators, and measurements along the feeder. One of the key functions of the network automation is to decrease duration and extent of the distribution network outages. The customer automation includes the automatic meter reading (AMR) and tariff control. [4] The smart grid concept enables more advanced customer automation systems e.g. for handling the increasing penetration of distributed energy resources (DER) [5].

2.1 Electricity distribution system

The electricity distribution system consists of a primary process and a secondary process. The primary process includes network equipment such as transformers, distribution lines, switching devices, and compensation devices, while the secondary process comprises the devices used to monitor and control the primary process. Intelligent Electronic Device (IED) is the common expression for the secondary process devices, such as protection relays, fault detectors, and the primary equipment controllers. [3] The primary and the secondary processes of the distribution system are presented in the Figure 2.

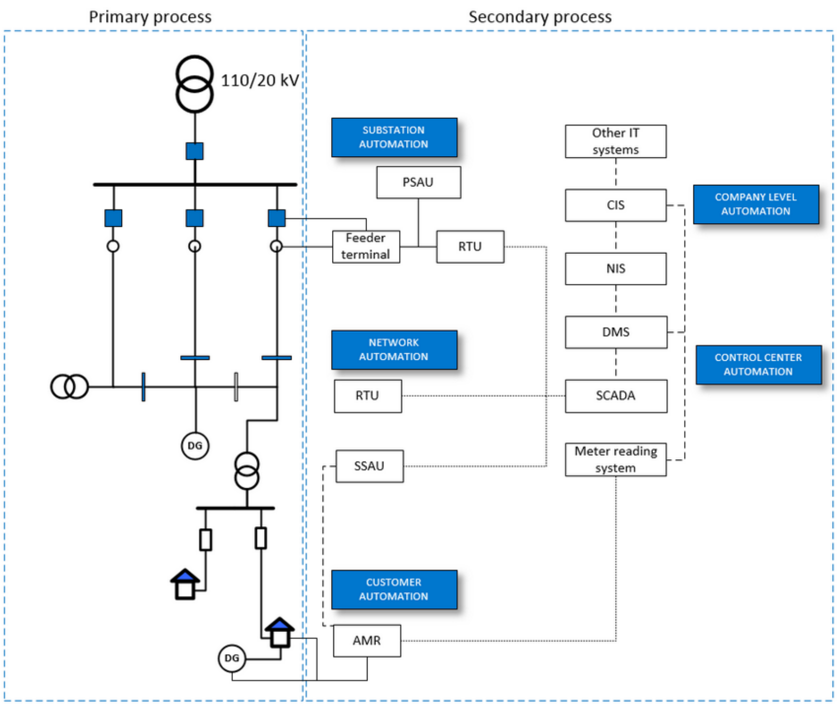

Figure 2. *The electricity distribution system with primary and secondary processes explained. Adapted from [3]*

The primary process of the distribution system can be divided into high voltage (HV), medium voltage (MV), and low voltage (LV) networks according to the voltage level. The high voltage distribution network is typically considered as 110 kV sub-transmission network operated by regional network operators (RNO). The voltage level of the MV network is typically 20 kV, but also other voltage levels are used, mostly in urban networks for historical reasons. The LV network consists of 0.4 kV lines connecting customers to the distribution substations, but 1 kV distribution network has also become more common in rural areas to partially replace 20 kV medium voltage branches. [4]

In the aspect of fault management, the medium voltage network can be considered as the most critical part, because of about 70 to 80 % of outages experienced by customers are originated from faults in MV network. [2] The medium voltage network is mostly built as meshed but used in normal operating conditions as radial feeders having open points for possible backup connections. Radial operation is beneficial because of the more straightforward process of network protection and operation. Ring operated MV networks are becoming more common, especially in the urban distribution networks due to more advanced protection systems and increasing amount of network automation. [4]

An increasing amount of distributed generation (DG) is also affecting to the nature of the distribution network. Traditionally electricity generation is centralized in the power plants connected to the transmission network causing unidirectional power flow from the primary substation towards customers. Due to DG connected into MV and LV networks, the nature of the MV network topology has changed more like meshed, having bidirectional power flows and multiple sources of fault current. These conditions brought new challenges for the network protection and voltage control, but also possibilities e.g. micro grid operation during major disturbance situations. [6]

2.2 Network Control Center automation

Control and monitoring of the distribution system are managed from the Network Control Center (NCC). Due to critical functions in distribution network operation, the NCC is usually equipped with Uninterruptible Power Supply (UPS) to ensure operation during a major disturbance. Network Control Center can be in one centralized location or multiple NCCs can exist to be responsible of a certain area of the distribution network or to act as a backup NCC in case of disruption of the primary NCC. Definition of the network control center can consist also so-called mobile NCC, where the operation of the network is performed from the laptop computer carried by the operator on duty. The main tasks of the NCC are: [4]

- Network control and state monitoring
- Fault management and reporting
- Maintenance planning and management
- Switching planning
- Customer support and information

The importance of the NCC is emphasized during a major disturbance situation. With well-organized and automated operations, increased number of faults can be managed, and number of customers resupplied. Network control center is responsible also for the electrical safety of the maintenance personnel working in the field. Therefore, all the switching actions in the medium voltage network must be confirmed by the network control center operator. [7]

2.2.1 Supervisory Control and Data Acquisition

Supervisory Control and Data Acquisition system is an information system used for real-time control and monitoring of a distribution system. It communicates with substation and network automation equipment via remote terminal units (RTU) and gathers information about the state of the distribution network as well as provides controllability of e.g. circuit breakers and remote-controlled disconnectors (RCD). According to [4], main functions of the SCADA system are:

- Management of the event data
- Management of the network switching state
- Remote control
- Remote measuring
- Remote configuration
- Reporting

Event data management provides information about operation of protection relays, switching device state changes, and fault detector operations. Combining event data with network model, it is possible to maintain switching state of the distribution network in the system. The process database of SCADA includes accurate information only on primary substations and substation devices, while the distribution network is usually presented as a simplified schematic view, including connections between primary substations and remote-controlled switching devices. [3] Process display of the SCADA system is presented in the Figure 3.

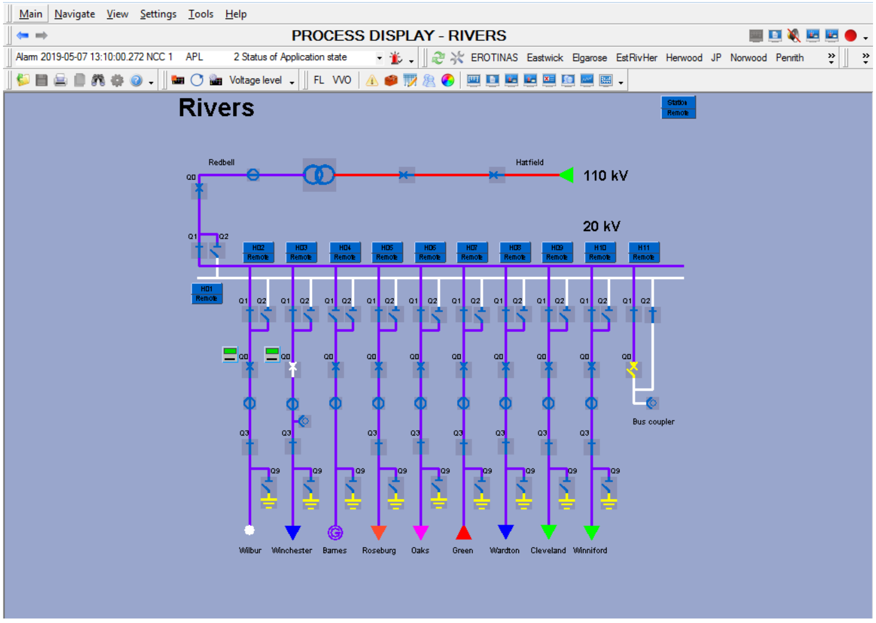

Figure 3. *Process display of the SCADA system*

The information of the switching state is critical for a safe distribution network operation. Therefore, SCADA systems are redundant having replicated applications on separate computers and backed up communications. In case of a system failure in the primary computer, the secondary computer takes the SCADA in control. These computers are also equipped with UPS devices to enable uninterrupted operation during outages. [8]

2.2.2 Distribution management system

Distribution management system is an IT system, which consists of applications to support the distribution network operation. While the SCADA system is designed to gather data and transmit control commands, distribution management system utilizes and analyzes data from several information systems such as SCADA, the network information system (NIS) and the customer information system (CIS). Usually the network model is presented in geographical view with a background map, which enables easier understanding of the network locations and e.g. a real-time field crew presentation on the map. [9] Example of the geographical network view is presented in the Figure 4.

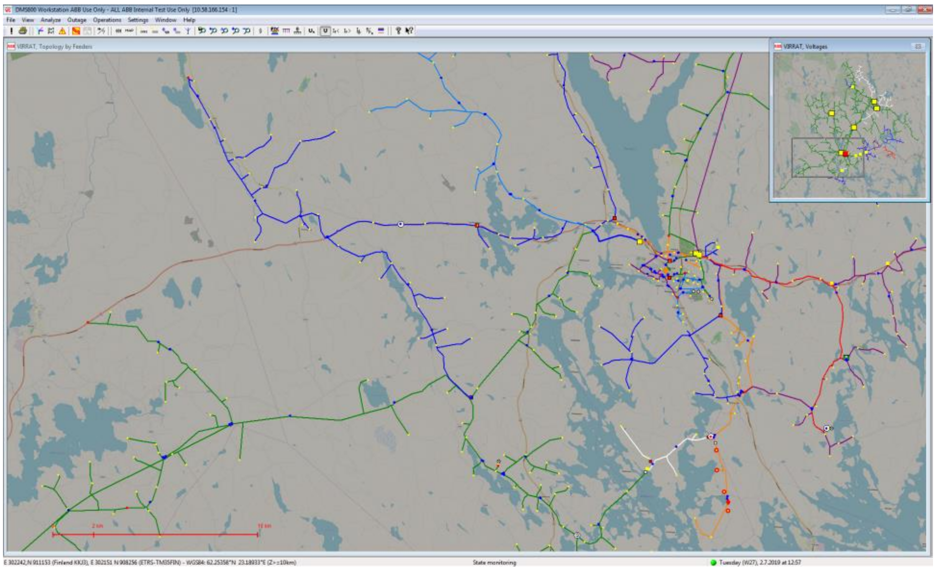

Figure 4. *Graphical network presentation of the DMS system*

With precise technical data of the network combined to the real-time information received from the SCADA, DMS can perform on-line analyses and calculations to assist the network operator. Main functionalities of the DMS are [4]:

- Topology management
- Switching state management
- Network and protection analysis
- Outage management
- Operations planning
- Reporting
- Customer service

DMS performs continuous or scheduled network and protection analysis to support operator’s decision-making or to provide initial data for automatic functions, such as automatic switching planning. Load flow of the network is calculated using customer group specific load curves in order to estimate voltages in network nodes. The estimation values are then readjusted based on the real-time measurements from the substation to achieve values that are more accurate. [9] In automatic fault isolation and service restoration, real-time load flow calculation is used for checking reserve connection capability, as possible voltage violations and thermal limits of the line sections are checked. From the fault management point of view, other important DMS function is the network protection analysis. Protection analysis ensures that both the short circuit protection and the earth fault protection are functioning properly. If the automatic supply restoration algorithm detects violation in operation limits of the relay protection, backup connection cannot be used. [10]

Fault management of the distribution management system comprises of fault handling function which lists and prioritizes unrepaired faults with fault information received from the SCADA. The NCC operator can examine the faulty feeder and the calculated fault locations from the graphical network view. [11] Based on the automatic switching planning, DMS may provide assisting switching sequences for fault isolation and supply restoration. After the fault has been repaired, reporting of the fault is assisted with a partially filled fault report form. The operator is left to correct the prefilled report and archive the fault report. [4]

Typical fault management of the DMS system also includes customer service functionalities, such as a web-based outage map, outage information and an automatic telephone answering machine (TAM) [12]. However, interactive mobile applications and SMS messages are mostly replacing the old TAM functionality, since customers must be provided with real-time information of the outage situation [7]. Real-time fault information can also be provided to field crews operating among the distribution area. While the locations and contact information of the field crews are shown in the network presentation, the NCC operator can dispatch them more efficiently. [13]

2.3 Substation automation

Substation automation can be divided into device level and station level automation. Device level automation includes e.g. operations of protection relays, controls of switching devices, voltage and current measurements, and regulation of voltage with a tap changer of the primary transformer. Station level automation consists of the local controlling of the substation, remote control communications, and sequence controls, for example to disconnect another primary transformer for maintenance. [4] Secondary process equipment and communications in the substation automation are presented in Figure 5.

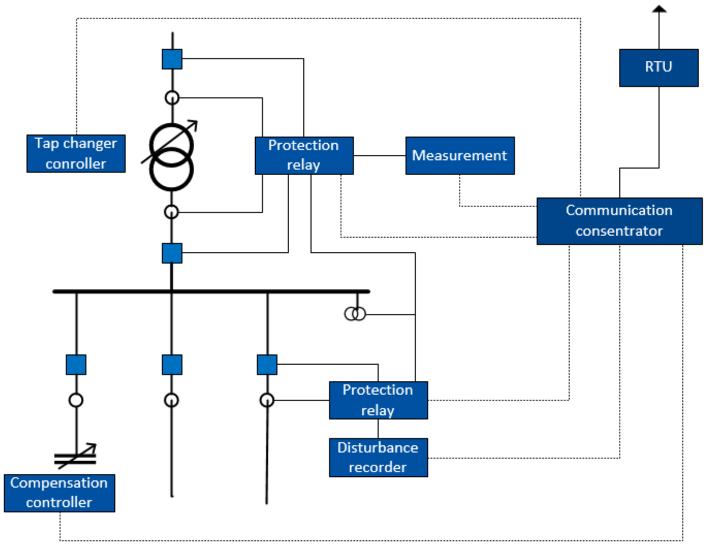

***Figure 5.** Substation automation equipment and communication. Adapted from [14].*

Modern substation automation concept includes feeder terminals that consist of micro-controller-based protection relays, measurements, and disturbance recorders in the same physical device. In case of a fault, the feeder terminal disconnects the supply by opening the circuit breaker, if the fault current magnitude exceeds the setting values of the relay. It also sends measurements, alarms, event data, and disturbance recordings to the SCADA system to locate the fault and analyze the disturbance situation. Communications from feeder terminals as well as other control and measurement devices are transmitted to the SCADA via communications concentrator as presented in the Figure 5. [8]

Distribution automation devices communicate to the upper level systems via Remote Terminal Units (RTU). The RTU gathers data from the network equipment and transmits it to the SCADA. In addition, control commands and setting values are transmitted from the SCADA to the substation automation equipment via RTUs. [15] Since the substation automation is critical part of the distribution network operation, communication is in most cases hardwired with optical fiber, or in old applications with copper wires. Communication links are also duplicated to ensure reliable operation in case of equipment malfunctions. [4]

2.4 Network automation

Besides automation in substations, there is also automation located along the distribution network. The network automation consists of remote controllable switching devices, such as remote-controlled disconnectors (RCD) and reclosers, and fault detectors. Nowadays, most of the network automation is located in the medium voltage network and secondary substations, but automation in the low voltage network is becoming more general. [14]

Remote controllable disconnectors reduce the interruption time experienced by the customer, since the network operator can isolate the fault directly from the NCC. In addition, RCDs reduce the human labor costs and allow automatic fault handling applications. To achieve the most cost-efficient operation of the network, remote-controllable disconnector stations are installed in the tie points and the most important branches of the MV network. Although the interruption duration is reduced, RCDs do not have an effect on the interruption amount experienced by the customer. To also reduce the interruption frequency, remote-controlled reclosers, also called sectionalizing circuit breakers, can be applied along the MV network. The recloser divides the feeder into independent protection zones. Therefore, fault occurring on a line section after the recloser zone before the recloser is not affected by the fault. This is especially beneficial on the long rural feeders that are prone to weather-related faults. [16] Location of the recloser on a long rural feeder is presented in the Figure 6.

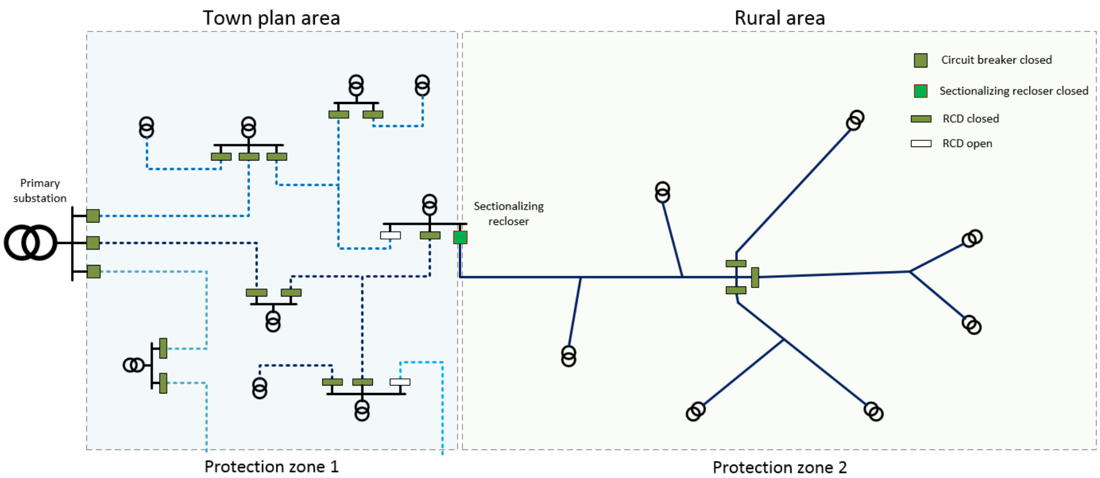

Figure 6. *Remote recloser on a long rural feeder*

Other crucial parts of the efficient fault location are fault detectors, which operate when the fault current passes by. Modern fault detector units can detect both short circuit and earth faults. While the short circuit operation is based on the overcurrent detection, the earth fault detection methods depend on the grounding type of the network. In neutral-isolated or compensated networks, the earth fault detection is based on the zero-sequence current measurement or on monitoring the direction of zero sequence voltage and current. Fault detectors can be divided into remote readable devices, which provide information for the SCADA and DMS, or locally readable devices that require a field crew to inspect them on site. [12] The basic principles of the regular and the directional fault detectors are presented in the Figure 7.

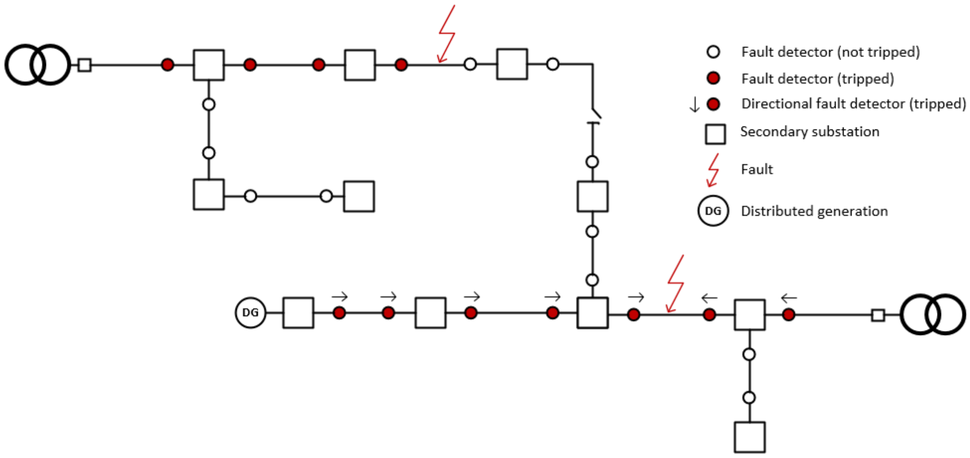

Figure 7. *Principle of the fault detector operation. Adapted from [17, 18]*

There have been reliability issues with the fault detectors, especially in the earth fault detection. In the neutral-isolated networks, the fault current fed by other feeders can cause a false operation of the detectors located in the healthy feeder or behind the fault. Also, a lightning strike can cause false operation of the fault detectors. Due to reliability issues, fault detectors have not been widely used by the DSOs. However, some DSOs are carrying out pilot projects to apply fault detectors in the network to experiment with the reliability and usefulness of the modern applications. [19] From the fault location point of view, equipping remote readable fault detectors widely enough would remarkably speed up the process and reduce undesirable trial switching.

2.5 Communication infrastructure

Increasing number of automation devices in the distribution system sets requirements for a reliable communication infrastructure. Communication technology varies between different kind of network applications based on its criticality, cost-efficiency, and distance between communicating units. For example, data flow between a protection relay is time-critical and therefore communication method must be fast enough and secured with a backup connection. On the other hand, e.g. communication for customer meter reading can be implemented with slower PLC or radio link communications. [4] Most common communication technologies used by DSOs are:

- Optical fiber and copper cable
- Radio link
- Mobile network (3G, 4G, GSM, GPRS)
- PLC (Power Line Carrier)
- Satellite network

Installation of physical connection, such as optical fiber and copper cables, is often an expensive and challenging process, especially with long distances. Therefore, these are only used in primary substation communication due to their high capacity and reliability. Network and secondary substation automation instead are usually communicating with radio link or mobile network. Due to an increasing amount of automation devices, old fashioned radio link and mobile networks are becoming bottlenecks in the two-way communication requirements in the smart grid concept. Hence, 3G and 4G mobile networks, capable of over 100 Mbit/s data rates, are replacing the old communication standards. On the other hand, new generation mobile technologies require more base stations to achieve the range of older technologies, which can be a limitation in some rural areas. [20]

Due to the high reliability requirements, usually less capable old technology, such as GSM and GPRS mobile networks, radio links, and satellite network, are used as the secondary backup communication. For example, in the major disturbance situation, high number of 3G and 4G base stations can be unsupplied, disabling the mobile network in some areas. Usually base stations are equipped with backup batteries, which still are made to sustain the power for only couple of hours. [7] To ensure the distribution network operation during a major disturbance, one of the operator’s high priorities is to re-energize these base stations.

3. FAULT MANAGEMENT IN MEDIUM VOLTAGE NETWORK

Efficient fault management is one of the main objectives for the operation of distribution network. By reducing the extent or the total duration of faults, distribution system operators can create cost savings in reduced standard compensations or by improved quality incentive of the regulation model of the Energy Authority. In addition, the Electricity Market Act defines the reliability requirements for the duration of outages. [21] The act states that:

"2) a failure of the distribution network due to a storm or snow load may not cause an outage longer than 6 hours in a town plan area:

3) a failure of the distribution network due to a storm or snow load may not cause an outage longer than 36 hours outside of the town plan area".

The DSO must fulfill the reliability requirements during a transition period by the end of the year 2028. However, there are exceptions in the enforcement date for distribution system operators that should renovate significant amount of the distribution network before the lifetime of the components, or the demand of cabling exceeds the calculated average cabling rate for Finnish distribution system operators. [21]

According to the standard SFS-EN-50160, the definition of an outage is a condition where the voltage at the supply point is less than 5 % of the nominal voltage. Type of the outage can be divided into planned outages and unexpected outages, as described in the Figure 8. The planned outage is a result of e.g. maintenance in the distribution network and affected customers are informed in advance. The unexpected outage is caused by a permanent or transient fault due to external factors, equipment failures, or incorrect switching actions. The unexpected outages in the electricity networks are categorized as short outages, having the outage duration of 3 minutes or less, or long outages in which duration exceeds 3 minutes. [4]

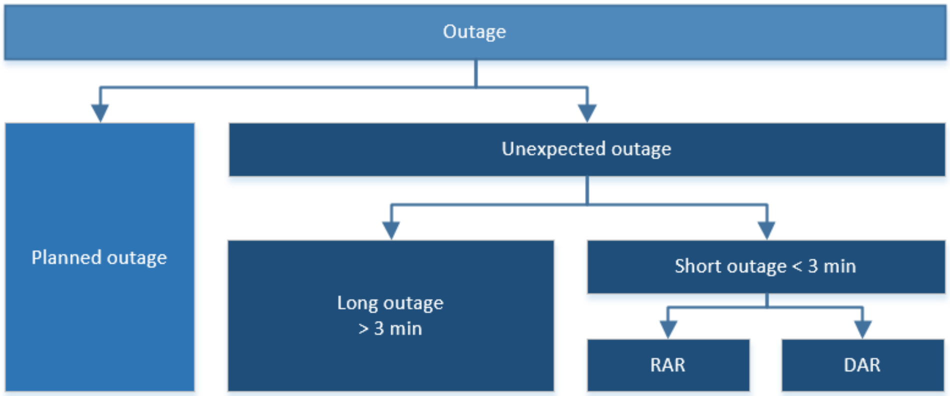

Figure 8. *Outage types in the distribution network adapted from [20]*

Temporary outages are typically cleared by the auto-reclosing sequence that consists of a rapid auto-reclosing (RAR) and delayed auto-reclosing (DAR). In the rapid auto-reclosing, supply is automatically restored under a one second time span to clear transient faults caused by e.g. lightning strike. If the fault is not cleared with the RAR, delayed auto-reclosing is applied, in which unsupplied time is longer, approximately one minute. During the DAR dead time e.g. arch caused by a tree branch can be extinguished. Fault is considered as permanent if the circuit breaker trips after the reclosing sequence, but the operator may still perform trial switching after, if fault is expected to be cleared. For example, in the urban network, auto-reclosing scheme may not be used due to thermal stress caused to underground cables. [4]

3.1 Regulatory incentives in fault management

Electricity distribution business being a natural monopoly, operation of the DSO must be regulated by the Energy Authority. The main objectives of the regulation model are to ensure high quality and reasonable pricing in the electricity distribution. The regulation model, presented in the Figure 9, is based on the deficit or surplus resulted from the difference between calculated reasonable return and adjusted realized profit of the distribution system operator. Therefore, the DSO is obligated to either refund the surplus to the customers by lowering the network fees and by developing the network or allowed to equalize the deficit by raising the network fees. [22] While the regulation model consists of several different variables, the most important factors, from the fault management point of view, are quality and efficiency incentives.

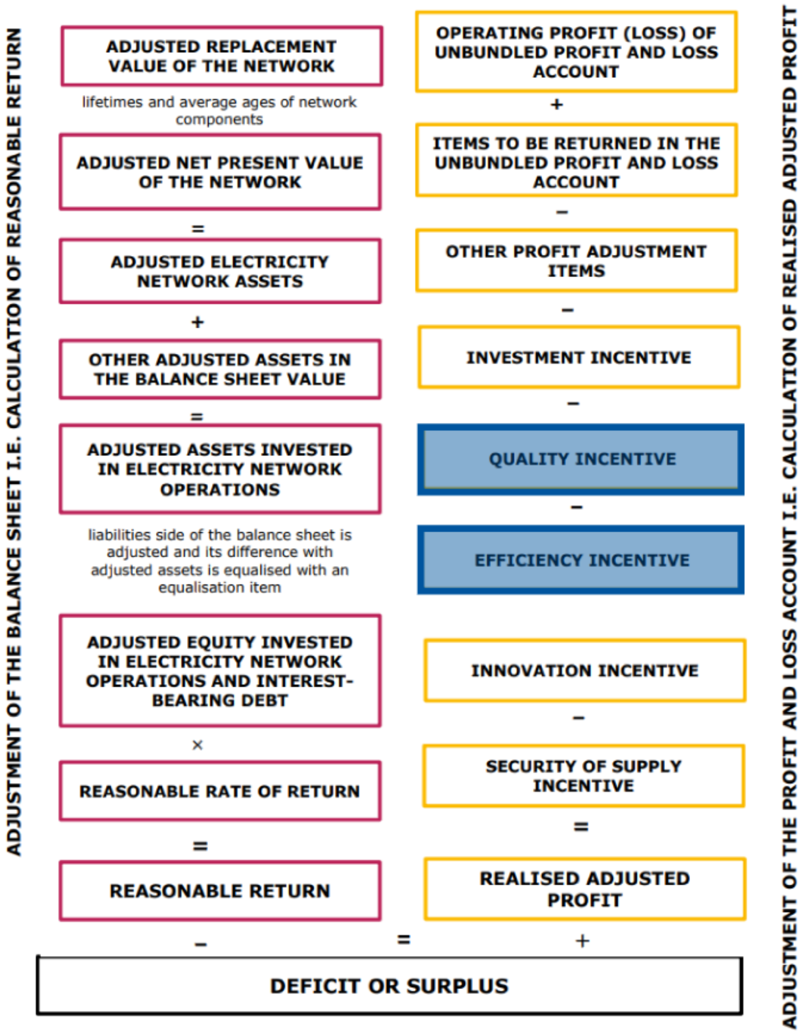

Figure 9. *The Finnish electricity distribution regulation method with highlighted quality and efficiency incentives. [22]*

The quality incentive encourages the DSO to improve the quality and reliability of the electricity distribution. The distribution reliability must exceed at least the minimum level defined by the Electricity Market Act, but a spontaneous enhancement of the reliability level benefits the DSO by decreasing the realized adjusted profit. The quality incentive is determined by comparing the total regulatory outage costs (KAH) of the inspection year to the reference level, which is calculated as an average outage costs of the two pervious four-year regulatory period. To even the peak values, the quality incentive includes maximum and minimum limits for the comparison degree. Thereby, outage costs exceeding these limits do not have an effect on the realized adjusted profit. Also, the quality incentive is adjusted to have maximum impact of 15 % in realized adjusted profit calculation. [22]

The efficiency incentive encourages the DSO to operate more cost-efficiently. Operation of the DSO is considered as cost-effective when the operational costs are small enough compared to the operational results. The total outage costs of the efficiency incentive comprise the cost caused by outages and the cost caused by preventing the outages. According to Energy Authority, these outage costs are modelled as an undesirable output variable rather than ordinary output variables. The automatic fault management is beneficial for improving the efficiency incentive since it lowers the amount of human labor enhancing the operational costs as well as reducing the costs caused by outages. [22]

Regulatory outage costs comprise the number and duration of unexpected and planned outages and the number of rapid and delayed auto-reclosings. The unit prices of the KAH parameters, presented in the 0, are valued according to the study conducted by Tampere University of Technology and Helsinki University of Technology in 2005. Values are calculated averages of the inquiry results from the different customer types of the DSOs all around Finland. [23]

Table 1. *Regulatory outage cost unit prices according to money value in year 2005. Adapted from [23]*

Unexpected outage		Planned outage		Rapid auto-reclosing	Delayed auto-reclosing
$h_{E,unexp}$	$h_{W,unexp}$	$h_{E,plan}$	$h_{E,plan}$	h_{RAR}	h_{DAR}
€ / kWh	€ / kW	€ / kWh	€ / kW	€ / kW	€ / kW
11.0	1.1	6.8	0.5	1.1	0.55

The total annual KAH costs are calculated using Equation 3.1.

$$KAH_{t,k} = \begin{pmatrix} KA_{unexp,t} \times h_{E,unexp} + KM_{unexp,t} \times h_{W,unexp} + \\ KA_{plan,t} \times h_{E,plan} + KM_{plan,t} \times h_{W,plan} + \\ RAR_t \times h_{RAR} + DAR_t \times h_{DAR} \end{pmatrix} \times \frac{W_t}{T_t} \times \frac{CPI_k}{CPI_{2005}}, \quad (3.1)$$

where

$KAH_{t,k}$	=	regulatory outage costs in year *t* in value of money for year *k,* [€]
KA_t	=	total outage duration in the MV distribution network, weighted by annual energies, [hrs]
KM_t	=	total outage number in the MV distribution network, weighted by annual energies, [pcs]
RAR_t	=	total outage number caused by rapid auto-reclosings in MV distribution network, weighted by annual energies, [pcs]
DAR_t	=	total outage number caused by delayed auto-reclosings in MV distribution network, weighted by annual energies, [pcs]
W_t	=	total distributed energy in year *t,* [kWh]
T_t	=	number of hours in year *t,* [hrs]
CPI_k	=	consumer price index in year *k*
CPI_{2005}	=	consumer price index in year 2005

3.2 Electricity distribution reliability indices

The Institute of Electrical and Electronics Engineers (IEEE) defines the international indices for electricity distribution reliability in the standard IEEE 1366-2012. These indices are categorized into sustained interruption indices, momentary interruption indices, load based indices and major power disruption indices. [24] This chapter introduces the most common IEEE reliability indices used in Finnish distribution system. Reporting of the IEEE reliability indices are not required by the Energy Authority, but they provide useful measure of the distribution system reliability for the DSO’s internal use.

SAIFI (System Average Interruption Frequency Index) indicates how often the average customer is affected by the sustained interruption over a defined time period [24]. The index is used for inspection of the line sections prone to faults. By these means DSO can allocate the network reinforcements to the right feeders and line sections more optimally. The SAIFI is calculated using the equation [24] (3.2.):

$$SAIFI = \frac{\Sigma N_i}{N_t} = \frac{CI}{N_t}, \quad (3.2)$$

where

N_i	=	Number of interrupted customers for sustained interruption *i* during the time period *t*
N_t	=	Total number of customers served
CI	=	Total number of customers interrupted

SAIDI (System Average Interruption Duration Index) indicates the average total duration of interruption for the customer during a defined time period [24]. The index is commonly used for reduction of the outage durations. Thus, DSO can optimize the placement of remote-controlled switching devices or analyze the benefits of the fault isolation and restoration process. The SAIDI can be calculated using equation [24] (3.3):

$$SAIDI = \frac{\Sigma r_i N_i}{N_t} = \frac{CMI}{N_t}, \tag{3.3}$$

where

r_i	=	Duration of the outage *i* in the time period *t*
CMI	=	Total customer minutes of interruption

CAIDI (Customer Average Interruption Duration Index) indicated the average time required to restore supply. The DSO can use this index to analyze and enhance the effectiveness of the fault management process. CAIDI can be calculated using SAIFI and SAIDI indices according to equation (3.4). [24]

$$CAIDI = \frac{\Sigma r_i N_i}{N_i} = \frac{\mathrm{SAIDI}}{SAIFI}, \tag{3.4}$$

Distribution system operators also use approximate indices based on the interruptions affected on the secondary substation. In this way, only the medium voltage network faults are considered, and customer information is not taken into account. Secondary substation level indices are presented as **T-SAIDI**, **T-SAIFI** and **T-CAIDI**. Calculation of these indices are conducted as a same manner as in equations 3.2, 3.3 and 3.4, but number of customers are replaced with number of secondary substations. [25]

Other commonly used reliability indices are **MAIFI** (Momentary Average Interruption Frequency Index), which can be calculated like SAIFI for short outages cleared by auto-reclosings, and **ASAI** (Average Services Availability Index) representing the percentage of time customer has received power during the defined study period. **CELID** (Customer Experiencing Long Interruption Durations) index is used to indicate the ratio of individual customers experiencing interruption durations longer than a defined threshold limit. [24] Thereby, the DSO can point out areas which do not meet the outage duration requirements set by the Electricity Market Act.

3.3 Faults in the MV network

Fault types in the electricity network can be divided roughly into short-circuit and earth faults. Since the Finnish medium voltage network is used as neutral isolated or resonant earthed with a Petersen coil, characteristics of the earth fault differs from the short-circuit fault. Therefore, different type of protection and fault location methods must be applied. [4] While short-circuit faults can be detected with current measurements due to high magnitude fault currents, earth faults need the monitoring of a neutral voltage and current or advanced applications, such as admittance-based protection units. [26]

Most of the permanent faults in the MV network are caused by weather-related issues, such as lightning strikes, strong winds, and heavy snow loads. Other causes of the faults are e.g. animals, human error or vandalism, and component breakdown due to ageing. Figure 10 illustrates the causes of the MV network faults in different types of Finnish distribution networks in year 2017. Statistics show that the rural distribution network is more prone to faults than the urban network. Majority of the rural distribution network faults are a result from long overhead line feeders exposed to the severe weather conditions and wild animals. [27] Strong winds and heavy snow loads cause trees or tree branches to fall over the distribution lines, but also damage the network structure itself. Especially the support structure of the overhead line poles or even the conductor can break down due to stress caused by the heavy snow. Rural networks typically include also plenty of aged components that increase the possibility of a component failure.

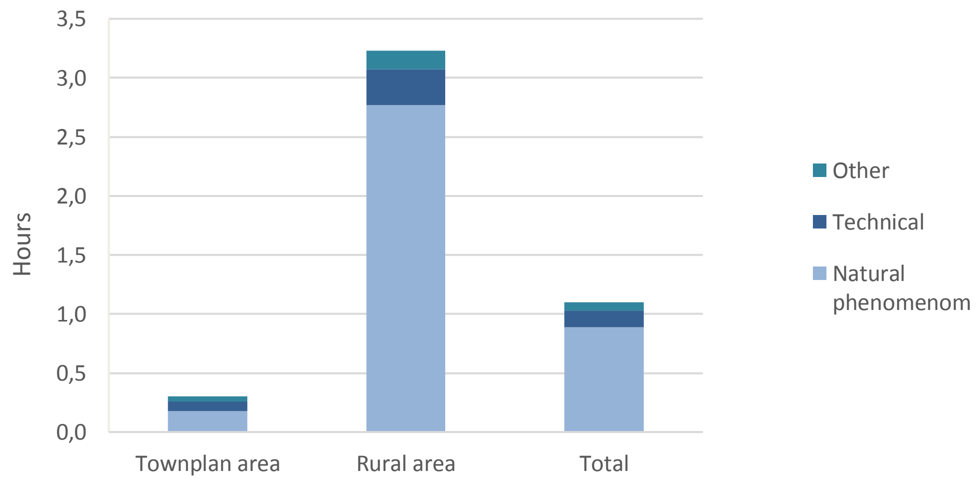

Figure 10. *Average interruption time caused by unexpected outages adjusted by the number of customers in year 2017. Adapted from [27]*

Instead of the environmental causes, urban distribution network faults are typically caused by human error or vandalism and component failures. A typical human error related issue is underground cable damage caused by excavation work. Therefore, it is important to maintain precise information of the cable routes and depths in the network information system and use cable detectors to locate the cables before excavation. As seen in Figure 10, number of outages is also remarkably smaller than in rural networks. Despite of the smaller number of faults, duration of the repair work of a single fault may take longer time due to most of the network consisting of underground cables. Single fault in urban network can also cause harm to a greater number of customers or even lead to major power disruption. Therefore, the scope of the urban fault management is more focused on prevention of the faults than preparation for the major disturbance situations. [28]

3.3.1 Short circuit faults

Two or more phase conductors connected directly with an arc or through a fault impedance cause a short circuit fault. The situation is usually caused by a fallen tree branch on the overhead line or a broken insulation. The most common types of short circuit faults are 2-phase and 3-phase short circuit. Detection of the short circuit is rather simple because of high magnitude of the fault current, which is typically greater than the load current. Due to the high fault current, short circuit faults require rapid clearing to prevent exceeding thermal withstand capacity of conductors and network equipment. Rapid clearing is also necessary due to voltage dip caused by the three-phase short circuit. When this occurs near the substation, voltage dip affects all the customers fed by the substation. [4]

On the protection point of view, it is necessary to define the highest 3-phase short circuit current to ensure the withstand capacity of the conductors. Typically, fault current is approximately 5-12 kA when the 3-phase short circuit occurs in the busbar of the primary substation. As the distance of the fault and the substation increases, the fault current is decreased by the effect of the conductor impedance. Therefore, 2-phase short circuit fault at the end of the long feeder can be so low that the protection relay is not operating. When the load current of the feeder is high, network reinforcements may be needed to ensure selective and reliable operation of the feeder protection. [4]

3.3.2 Earth faults

An earth fault occurs when the live part of the network has conductive contact to earth. The earth fault may develop in a network part having protective earthing, such as over voltage protection spark gap, or in an unearthed part of the network by e.g. tree leaning against the overhead line conductor. [29] Majority of the earth faults in an overhead line network are caused by fallen trees due to severe weather conditions, such as strong wind or heavy snow loads. On the contrary, earth faults in an underground cable network are usually caused by material ageing failures or excavation work. While the frequency of faults is much lower in cabled networks than in overhead line networks, duration of the interruption is often longer due to a more difficult locating and repair process. [30]

The earth fault current in Finnish MV networks is low due to neutral isolated operation and unfavorable earthing conditions of the soil. Therefore, detection of an earth fault cannot be based on the magnitude of the fault current but monitoring of a zero-sequence voltage must be introduced. [29] Due to compensation, earth faults in cabled networks have often an intermittent characteristic, which means that fault self-extinguishes and re-ignites rapidly. When the fault currents of the compensated system are relatively low, and conductor does not have a solid earth contact due to partially damaged insulation, fault will be extinguished immediately after the breakdown. Due to reduced insulation capacity, cable will break down after the voltage of the faulty phase rises. [31] These kinds of faults are hard to detect and often require more sophisticated methods, such as analysis of frequency, harmonics, and transients. Modern protection relays can be equipped with multi-frequency admittance-based functionalities that can also detect the intermittent earth faults. [26]

Although earth fault currents and touch voltages can be limited due to compensated or neutral-isolated nature of the medium voltage networks, voltage in the healthy phases can rise to magnitudes as high as phase-to-phase voltage. Therefore, recurring earth faults can cause overvoltage which may become dangerous for customers or cause damage to the network devices and insulation. Overvoltage can also cause single-phase earth fault to develop into cross-country earth fault, in which another earth fault occurs in the second network location. In cross-country fault, the fault current is usually high and due to poor soil conductivity, currents go through well conducting routes, such as communication cables and drainpipes, causing thermal damage. [30]

A high impedance earth fault occurs when e.g. a tree is leaning over the covered overhead line or a fallen overhead line on the load side. Due to the high impedance of the fault, the fault current and touch voltage are usually low. Because of the low magnitude of the fault current, earth fault protection may not isolate the fault, but instead set an alarm to indicate possible fault to the operator. In some cases, even the alarm is not functioning, and the information of the fault is received from the customer notification. [4]

3.4 Major power disruption

A major power disruption occurs when extreme weather conditions or other incidents, such as human errors or vandalism, cause a widely spread and long-lasting interruption in the electricity supply. The IEEE Standard defines the major power disruption as Major Event that exceeds reasonable design and operational limits of the power system. The Major Event includes at least one Major Event Day (MED) in which System Average Interruption Duration Index (SAIDI) exceeds a MED threshold value. There is also a definition by Finnish researchers that defines the major power disruption as a condition where more than 20 % of customers are without electricity or there is a several hour long fault in the 110 kV line, the 110/20 kV primary substation, or the primary transformer. [32]

Major power disruptions caused by severe weather conditions have caused massive outage costs to the rural DSOs, as long overhead lines located in the forest are prone to fallen or bent trees caused by strong winds and heavy snow loads. Due to challenging weather conditions as well as multiple simultaneous faults in widespread distribution network, restoration of the electricity supply can take several days for certain customers. The most severe power disruptions in the past decade has been Tapani and Hannu storms in December 2011 causing outages to over 500 0000 customers in Finland. [7] These situations lead authorities to enact a new Electricity Market Act in 2013 that includes e.g. maximum outage durations and standard compensations for the customer.

To achieve proficient operation during a major power disruption, DSOs usually have a trained emergency organization, which also includes representatives from local authorities. Through co-operation of different parties, it is possible to ensure better situation awareness from the early stages of the disruption to the full clearance of the faults. [33] By automatizing certain procedures, such as outage notification, fault prioritization, location and isolation, in fault handling, operative personnel of the DSO are freed to conduct the overall situation. The situation awareness communication flow between different parties is presented in the Figure 11.

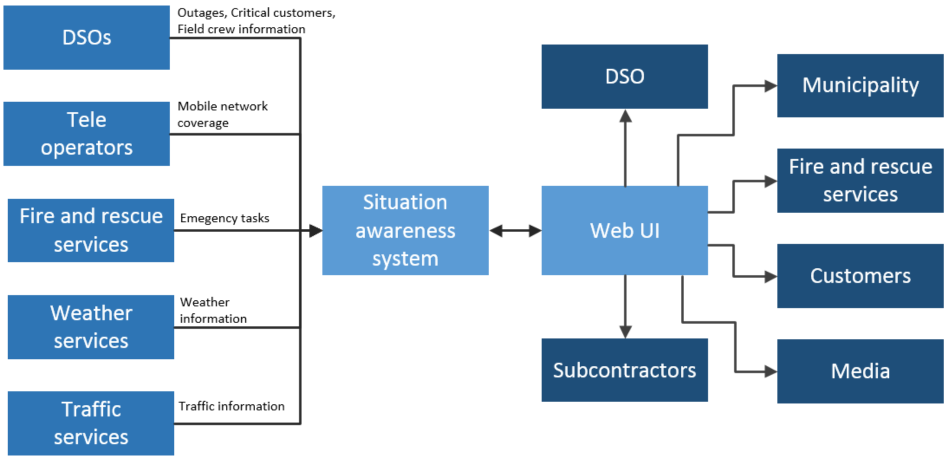

Figure 11. *Data flow in the situation awareness system. Adapted from [7, 33]*

Publication [33] presents a dedicated Situation Awareness system that combines information of the distribution network, mobile networks, weather forecasts, traffic information, and status of the critical customers. By these means, the DSO can predict the upcoming state of the disturbance and conduct the operation in the field. Monitoring and forecasting the status of the mobile network base stations exposes the possible communication failures of the remote-controlled equipment. Thereby, the operator may prioritize the supply restoration or send back up power supply to keep the communications alive.

3.5 Fault management process

Fault management process starts with a detection of a fault. In case of a circuit breaker tripping, faulty feeder is isolated automatically, and fault information is sent from relay to the SCADA. The fault information is then received to DMS via SCADA interface. With a graphical topology presentation, the NCC operator can identify the faulty feeder and estimate the possible fault location based on heuristic knowledge or calculated fault distance from fault current measurement. Information of the fault location can also be received from a customer call. [12] In case of a high impedance earth fault, protection relay may not even detect the fault and the whole fault management process starts from the customer informing the fault. Figure 12 illustrates the common process flow of the fault management process in the medium voltage network.

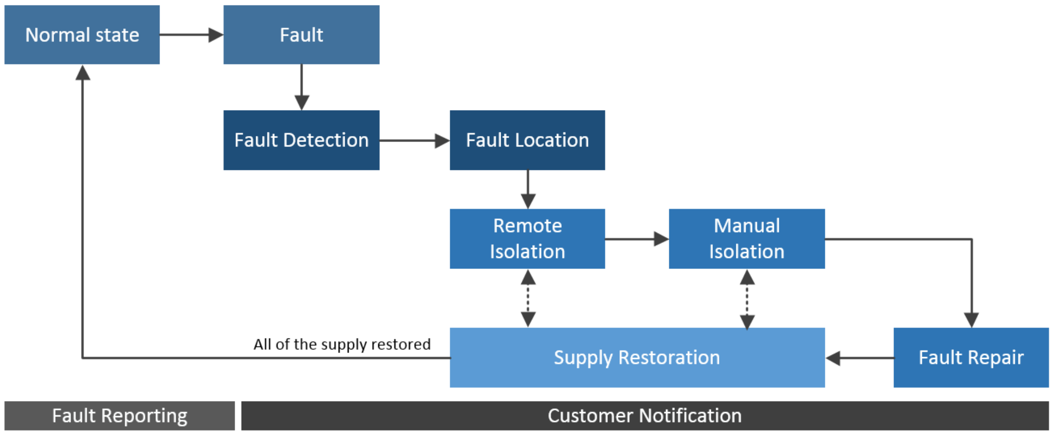

Figure 12. *Diagram of a conventional fault management process. Adapted from [19]*

After a coarse estimate of the faulted line section, the fault is tried to isolate using remote controlled disconnectors if they are available in the faulty feeder. When there is no exact fault location available, trial switching method is used to locate and isolate the fault. In trial switching procedure, operator opens one or more disconnectors along the faulty feeder and closes the circuit breaker at the substation against the possible fault. If circuit breaker trips, fault is located at the downstream part of the open disconnector. There are two common models to perform the trial switching: a bi-section and a zone-by-zone rolling method. [12] More specific details of these methods are introduced in chapter 4.1.3.

A field crews are dispatched to manually isolate the fault after the remote isolation. If the faulty line section is still unknown, the field crew can perform further trial switchings in co-operation with the operator. Electricity supply is restored to as many customers as possible after the isolation to minimize outage costs. Network and protection calculation of the DMS is used to check possible constraint violations when determining the possible backup connections. After the faulty zone has been isolated to the desired extent and supply partially restored, the field crew can start the repair work.

It is highly important to ensure the electrical safety when field crew is working at the distribution network. According to standard SFS 6002 ‘Safety at electrical work’, the operator is responsible for a safe operation in the field. Therefore, all medium voltage switching operations must be approved and a field crew must be granted with a work permit by the operator. Also, a person responsible for working and electrical safety on site must be nominated before any actions are taken in the field. The person responsible for on-site safety must ensure that there is no possibility the working location to be accidentally supplied. To achieve these conditions, SFS 6002 [34] states that the working location must be:

- Completely disconnect with an air gap or insulation
- Secured against reconnection of the electricity supply
- Verified to be unsupplied with measurements taken from all phases
- Equipped with work earthing
- Protected from nearby live parts

According to the standard, a field crew is not allowed to operate in severe weather conditions, such as heavy rain, strong wind, or thunder. Because of this, repair work or manual switching actions are usually delayed in major disturbance situations. [34]

After the fault is repaired, supply is restored for the rest of the customers and switching state of the network is restored to the initial state. Operator is also responsible for reporting the fault. Reporting is made easier with the DMS, which stores the starting and ending times with switching events occurred in between. In addition, DMS calculates key figures of the fault, such as affected customers, customer hours and not supplied energy, to streamline the reporting process. [12]

Customer service and notification are also DSOs responsibilities during fault situation. The Electricity Market Act states that customers must be informed about ongoing faults and estimated durations of the fault. The information about the fault can be provided with automatic telephone answering machine that contains pre-recorded or speech synthesizer created feeder and location names combined with an estimated repair time. [12] Nowadays, automated SMS messages and web outage maps have mostly replaced the telephone answering machine. Because of the automatic notification, unnecessary phone calls from the customers can be reduced to relieve the workload of the operating personnel in the control center. This is especially beneficial during a major disruption, when plenty of customers are without electricity. [33]

3.6 Impact of distributed generation in protection and fault management

An increasing amount of distributed generation is changing the nature of the electricity generation from centralized power plants into smaller decentralized power generation units connected into medium and low voltage networks. Power flow of the distribution network is becoming more and more bidirectional instead of traditional convention, when power flows were unidirectional from the primary substation towards customer. [18] Connection of the DG with active network management (ANM) provides many possibilities e.g. avoiding or delaying network reinforcements, reducing network losses, and micro grid operation during major disturbance situations. However, distributed generation causes also challenges in network protection, fault management and voltage rise in weak networks. [35]

3.6.1 Protection blinding

The principle of an overcurrent protection is based on the minimum fault current that causes the relay to trip. Protection zone of a certain CB must cover the fault current level even from the end of the feeder, where fault current has its minimum value. The fault current contribution of the DG unit can disturb the operation of the protection relay by delaying the operation or even block the operation completely. This phenomenon is called protection blinding and it is caused by the DG unit feeding the fault current parallel with the feeding substation. [18] The parallel fed fault current by the DG unit is presented in the Figure 13.

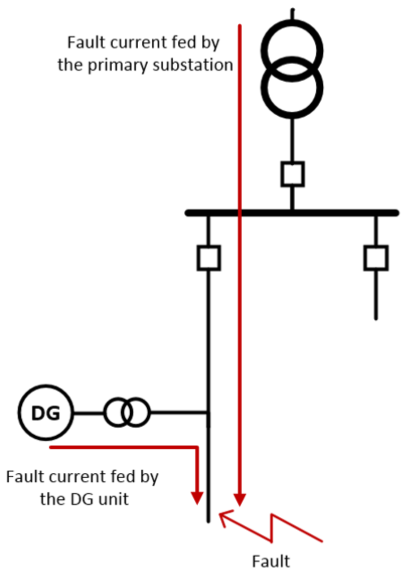

Figure 13. *Fault currents fed by the primary substation and the DG unit. Adapted from [35]*

Even if the operation of the relay is not completely interrupted, the protection-blinding effect can delay the operation of the relay that can cause the thermal limits of conductors and components to exceed. The blinding problem can be overcome by configuring the relay with more sensitive tripping values, but this can lead to a sympathetic tripping by fault on the adjacent feeder, tripping caused by starting currents of the DG units or tripping by load current during maximum load conditions. The protection blinding can also be avoided by reinforcing the distribution network, but it usually makes connecting the problematic DG unit economically unfeasible. [18]

3.6.2 Adjacent feeder tripping

A distributed generation can cause unnecessary tripping of the feeder, when fault occurs in the adjacent feeder. In situation like these, DG unit located on the adjacent feeder feeds a fault current trough a substation to the faulted feeder and causes an unwanted operation of the feeder protection. This problem occurs when the fault and the DG unit are located near the substation, fault current capacity of the generation unit is large enough and feeder is not protected with a directional protection. [18] Protection selectivity problem, or so-called sympathetic tripping, is presented in the Figure 14.

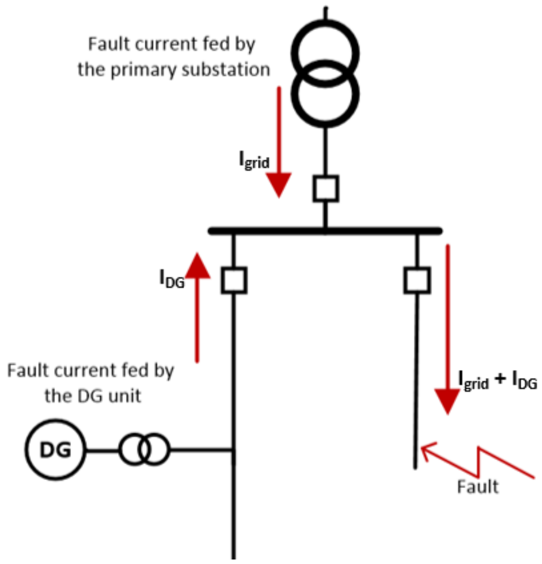

Figure 14. *Tripping of the adjacent feeder. Adapted from [35]*

Selectivity problems can usually be avoided with adequate protection relay settings. This can be overcome by changing the current settings of the relay located in the DG feeder, but in most cases, it cannot be done to ensure suitable protection in all of the fault situations. [18] Instead of changing the current limits, the operation time of the relay can be set slower in the feeder, including the DG unit. If a delayed operation time of the protection is used, precautions must be taken that thermal limits of components are not exceeded. In case these solutions are not possible, directional protection can be applied. Directional protection is the most definite solution, but it requires replacement of the old relays with new ones, which causes expenses. [35]

3.6.3 Failed reclosing and loss of mains protection

Temporary faults are typically cleared by automatic reclosing, in which a fault arch is extinguished during non-supplied time. If the first reclosing fails, couple of more reclosings are made before the circuit breaker is opened permanently. If distributed generation units are connected to the faulty feeder, voltage is sustained, and the fault arch is not extinguished. Therefore, all the DG units must be disconnected before the reclosing sequence is applied. Figure 15 illustrates the failed reclosing supplied by the tDG unit and the successful case of DG units disconnected before the reclose.

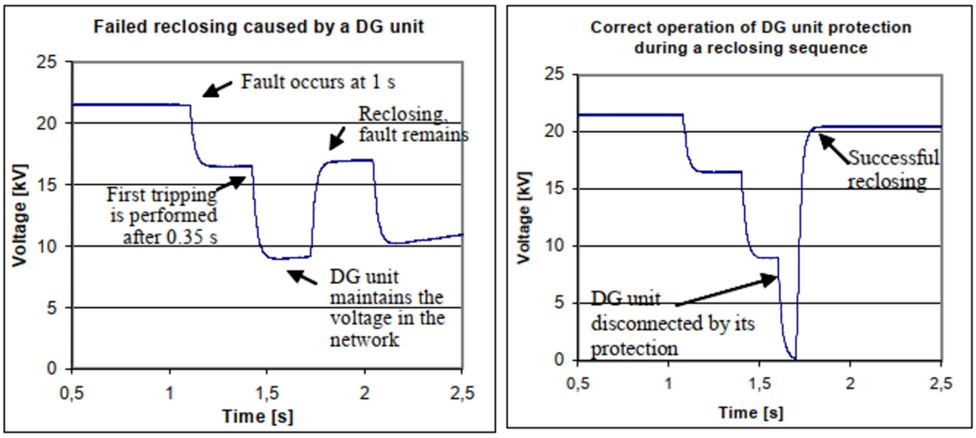

Figure 15. *Failed reclosing due to DG unit [35]*

To coordinate the protection scheme with the feeder and DG protection, distributed generation units must be equipped with a loss of mains (LOM) protection. Thereby, the DG unit is disconnected instantly after the connection to the grid has been lost. In addition, after the fault has been cleared, the reconnection of the distributed generation must be done carefully to avoid harmful stress to the DG units. [36] The DG unit disconnected from the network must also be considered in a supply restoration. After the fault, distributed generation is not supporting the feeder and loading conditions differ from the pre-fault situation. Thereby, supply restoration may not be possible even if constraint violations are not exceeded the load flow calculation of the pre-fault state. Modelling the DG units to the distribution management system is essential due to the increasing penetration of distributed energy resources. [18]

4. AUTOMATIC FAULT MANAGEMENT

Automatic fault management defines an entity of automatic or semi-automatic functionalities to detect, locate, and isolate a fault and restore electricity supply to non-faulted parts of the distribution network. The objective for automatic fault management is to minimize outage costs, human labor, and avoid unnecessary switching operations. [12] Automatic fault management does not affect the number of outages, but duration and extent of the outage can be reduced. Especially in a major disturbance situation, multiple faults are occurring at the same time and operators are not able to handle all of them in desirable time. Distribution networks are geographically widespread, consisting of densely populated urban areas and forested rural areas especially prone to faults. [37] Despite of the major investments made to increase the reliability by cabling, it is not cost-efficient to renovate the whole network, but instead increase the amount of automation and utilize existing automation more efficiently.

The control strategy of automatic operations can be categorized into centralized and decentralized schemes. [5] In the centralized method, automatic fault management is implemented as a part of the SCADA and the distribution management system. The centralized system can utilize the information of the whole network, including switching state and calculations for load flow and protection. Therefore, the state of the network can be checked before and after the fault to plan the most optimal use of backup connections or to check the constrain violations of switching operations. Excessive amount of data can also be considered as a disadvantage, since it must be stored and transferred in real-time. [10] The basic principle of the centralized scheme is presented in the Figure 16.

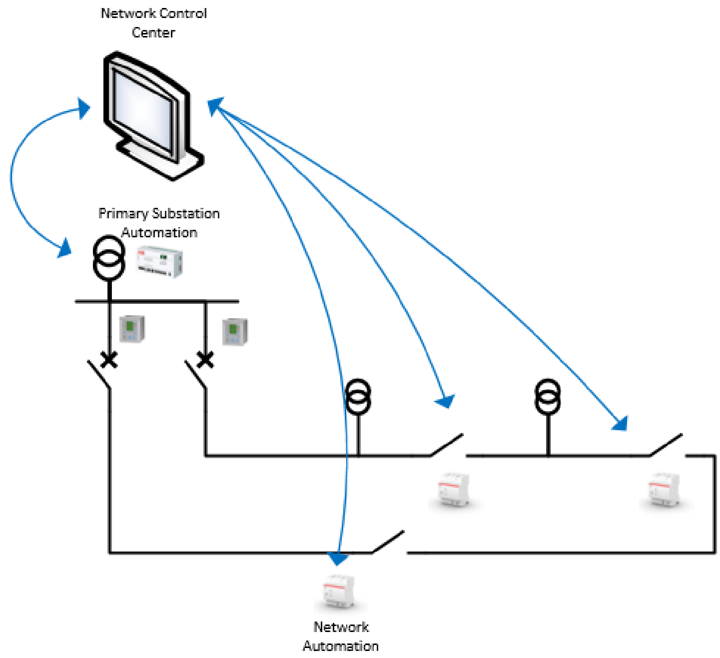

Figure 16. *Simplified schematic of the centralized FLIR concept. Adapted from [10, 38]*

Instead of collecting and analyzing the data in one centralized system, operations can be distributed to the intelligent controllers of the primary substations and the secondary substations. In a so called decentralized or distributed agent-based control scheme, substation controllers are communicating with each other, in which information of the fault indication is queried towards downstream of the feeder. When the faulty section is located, substation controllers isolate the line section and send information to the primary substation and the NCC operator. [38] Compared to the centralized method, benefits of the decentralized system are its simplicity and fast operation. However, to achieve a large-scale decentralized control system, major investments must be made, equipping secondary substations with automation. The basic principle of the decentralized solution is presented in the Figure 17. One solution is to use both centralized and decentralized schemes together applying local control to the most critical parts of the network. [10]

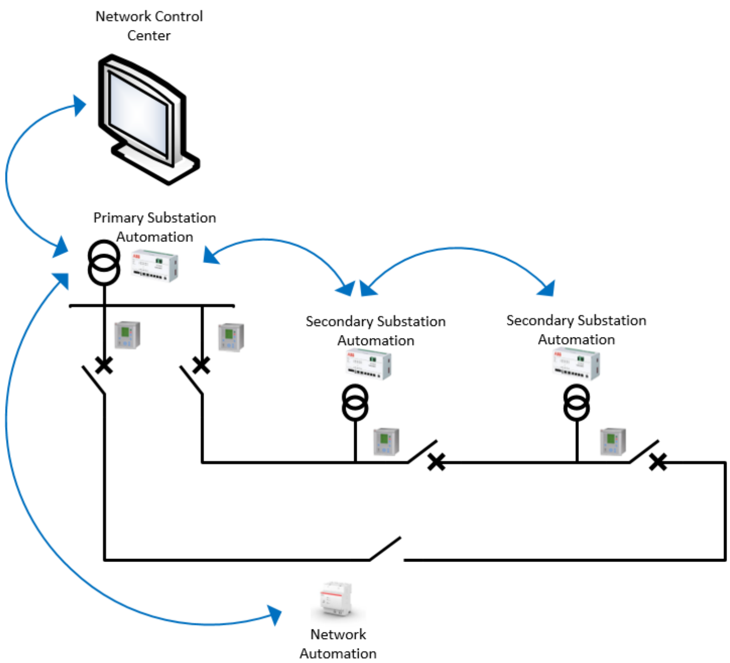

Figure 17. *Simplified schematic of the de-centralized FLIR concept. Adapted from [10, 38]*

Regardless of the solution method of the automatic operation, the final responsibility of the process and electrical safety belongs to the NCC operator. Hence, there have been disagreements whether a computer should perform all the actions, or should a human operator confirm the actions made by the automation. [39] A comprehensive FLIR solution should include different levels of operation from the assisting mode confirmed by the operator to the fully independent mode operated by the automation. Especially in a completely automated solution, every possible safety issue must be considered. Possible safety issues for the FLIR operation are e.g. a field crew working alongside the faulty feeder, loss of communication, or an incorrect operation of switches.

4.1 Fault location and isolation

The first step in the FLIR function is fault detection. When a permanent fault occurs in the medium voltage feeder, protection relay trips, circuit breaker is opened, and faulty feeder is de-energized. Information about the fault is then sent to SCADA and forwarded to DMS. Fault detection in case of a short circuit fault is usually straightforward process due to high magnitude of fault currents. Earth faults instead require additional methods in compensated or neutral-isolated distribution networks due to fault currents often lower than the load current. [12]

There are several ways to determine the possible location of a fault depending on the type of the fault and the fault information available. Fault location methods are dependent on information gathered from the protection relay and the fault detectors combined with the network model stored in the database. Not always fault current measurements or operations of fault indicators are available or feasible enough to estimate the fault location. Therefore, statistical and probability-based methods, as well as methods using trial and error, must be used. [12]

To achieve the most effective fault location process, these methods are combined. If available, the first inference of the possible location is carried out with a fault distance calculation based on the fault current measurements. These variables are then combined with e.g. fault indicator operations, environmental or component condition-based factors to deduce possible faulted zones by fuzzy reasoning. [12] A limitation of the possible fault area reduces a number of potentially harmful and time-consuming trial switching. Also, supply can be restored to the certain disconnector zones, if they can be deduced as un-faulted before the fault is completely located and isolated.

4.1.1 Fault distance calculation

The fault distance calculation, based on the current and voltage measurements, is the main information used inferencing the fault location in case of a short circuit fault. Due to the earthing type of the Finnish distribution network, earth faults cannot be located using the fundamental frequency fault current magnitude, but study of the transients and harmonics must be included. In calculational methods, measurements received from the relay are compared to corresponding calculated values of the network model in DMS. Therefore, correctness of the technical parameters and the switching state is a key factor in fault location deduction. [12]

Modern microprocessor-based protection relays usually provide a fault current measurement and information on the faulty phases. With this information, the system calculates all the points in the distribution feeder, where the calculated fault current meets the measured value. [40] Figure 18 illustrates the situation with multiple calculated fault distances. A maximum fault distance can be calculated with a fault resistance value of 0 Ω, but minimum distance is highly dependent on the fault resistance. Therefore, defining the minimum distance is remarkably more uncertain. [41] An accurate fault distance calculation solely based on current magnitude also requires information on the feeding network impedance and the distributed generation along the feeder. If the capacity of the DG is small enough, it can be reduced out of the calculation, but the increasing number of DG units requires them to be modelled in the fault current calculations. [42]

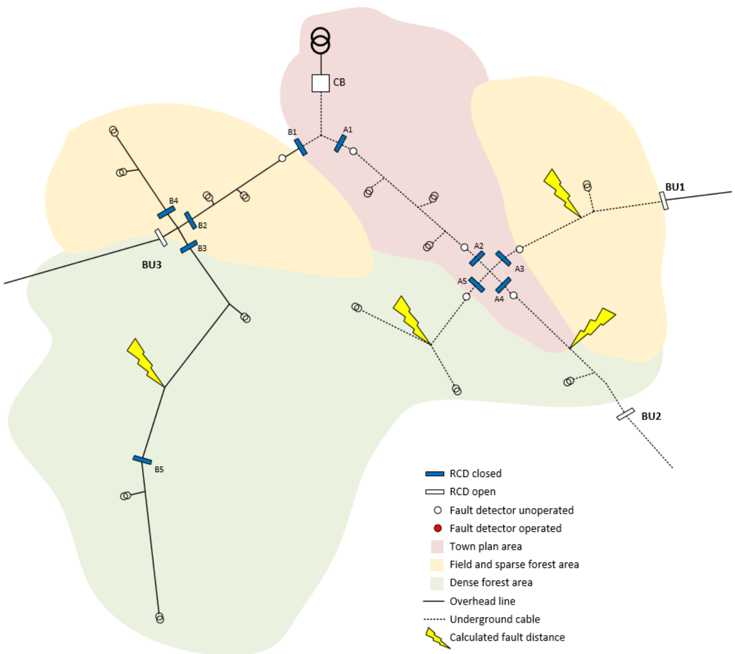

Figure 18. *Possible fault distances based on short circuit calculations*

A measured fault current includes also a load current component. The superposed load current component changes dynamically with the change of voltage during the fault, and thus it must be compensated using theoretical models presented in Equations 4.1 and 4.2 [41]:

$$\frac{P_1}{P_2} = \left(\frac{U_1}{U_2}\right)^{P_u}, \tag{4.1}$$

$$\frac{Q_1}{Q_2} = \left(\frac{U_1}{U_2}\right)^{Q_u}, \tag{4.2}$$

where U_1 and U_2 present the voltages before and during the fault, P_1 and P_2 are the corresponding active power and Q_1 and Q_2 the corresponding reactive power values. P_u and Q_u are the parameters used to model the voltage dependency of the loads. According to the analyses made in the distribution networks, the ranges of values are P_u = 1.5 – 2.0 and Q_u = 2.0 – 6.0. [41] Typically, these parameters are manually set in the DMS fault inference settings by the system user.

Accuracy of the fault distance calculation can be improved with voltage measurement in the substation. If both the current and the voltage are measured during the fault, the fault distance can be calculated using reactance of the faulty line. In addition to the improved accuracy of the distance relays, the reactance method can be used in the meshed network because the direction of the fault current is available. [41] After the relay has calculated the distance, either a reactance or a simple length value is transmitted to the DMS where it is compared to the line lengths of the network model.

The location of the earth faults has been problematic in the neutral isolated and compensated distribution networks. Since the fault current and the load current are in the same order of magnitude, fundamental frequency measurements cannot be used at the precise location of the earth fault. [40] However, more advanced methods have been developed that studies the measured harmonics and transients at the beginning of the earth fault. These methods have been successfully tested in the 110 kV sub-transmission network, but in distribution networks, the high fault resistance limits the use of these methods. It has been studied that fault resistances over 50 Ω dampen the transients below the limit where the fault distance calculation is not accurate enough. [43] Sometimes fault occurs as a double line to ground fault, where both earth and short-circuit protection units operate, and if the short-circuit protection registers the fault, it can be located using fault distance calculation. [17]

4.1.2 Fault inference

Measurements received from the relay and fault indicator operations can sometimes be inadequate to deduce the exact location of the fault. As the distribution system contains plenty of uncertain variables and heuristic information, inference methods using artificial intelligence (AI) are used to combine shattered information into qualitative variables. [44]

The fuzzy logic is widely used in the field of process control. Variables in the fuzzy logic are rather considered as linguistic objects, such as relatively high or almost empty, than strict 0 or 1 values. Fuzzy logic allows uncertain, heuristic, and qualitative information to be determined as membership functions of fuzzy sets. That kind of information could be e.g. a fault detector operation, an overhead line located in the forest, or condition of the network component. [12] Unlike straightforward rule-based system, the fuzzy logic approach may be used with multi-source information containing inaccurate transient measurements and versatile environmental factors. [44] The inference model of fault location is presented in Figure 19.

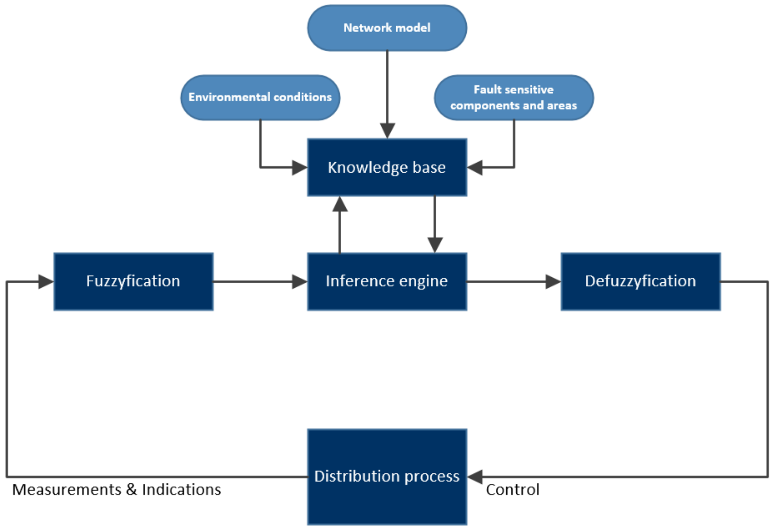

Figure 19. *Fuzzy-logic based fault inference system. Adapted from [12, 44]*

In the fuzzy logic system, measurements and indications are fuzzyfied into membership functions of fuzzy sets and then combined with fuzzyfied information of the knowledge base as presented in Figure 19. For example, severe weather condition data affects the plausibility of fault indicator operations or increases the weight of the overhead lines located in the forest. After the uncertain factors, measurements, and indications are combined, the fuzzy set with the highest membership is defuzzyficated into a crisp value of the inferred fault location. [44]

Artificial neural networks (ANN) differ from the common expert system for not needing a knowledge base to operate. Instead of predefined rules, ANNs are trained with numerous real cases or simulations. Artificial neural network consists of input layer, hidden layers, and the output layer. Each of the layers contains multiple neurons, which are connected to all the previous and the next layer neurons. A single neuron can be considered as a processor forming a single output from multiple input variables using a simple non-linear equation. Neuron of the ANN uses weights to determine the proportion of each input to be summed and equated with an activation function. The training procedure of the ANNs is based on minimization of the error between example input data and target output values. On each of the training steps, weights of the neurons are adjusted to achieve improved output. [44]

Today's distribution networks are constantly becoming more complex, having large amount of data to be processed. Therefore, the artificial neural network solutions can be beneficial because of ANNs high performance of processing large amounts of data from multiple sources. Artificial neural networks are also resilient to partially incoherent data and can recover from faulty operations by itself. Potential applications for artificial neural networks are e.g. fault inference using data from transient and harmonics measurements, disturbance recordings, and variety of open data. [45] Although the ANN applications are prominent possibility in distribution network fault management, deeper understanding is not in the scope of this thesis.

Fault indicators are one of the key elements in fault inference, especially in the cabled urban networks. Fault indicators are becoming more common in new urban area secondary substations and disconnector stations, but devices installed in overhead lines are usually found out to be unreliable and too expensive for large scale deployment. [46] Due to uncertain operation, plausibility of the fault indications must be checked before using the data in fault inference.

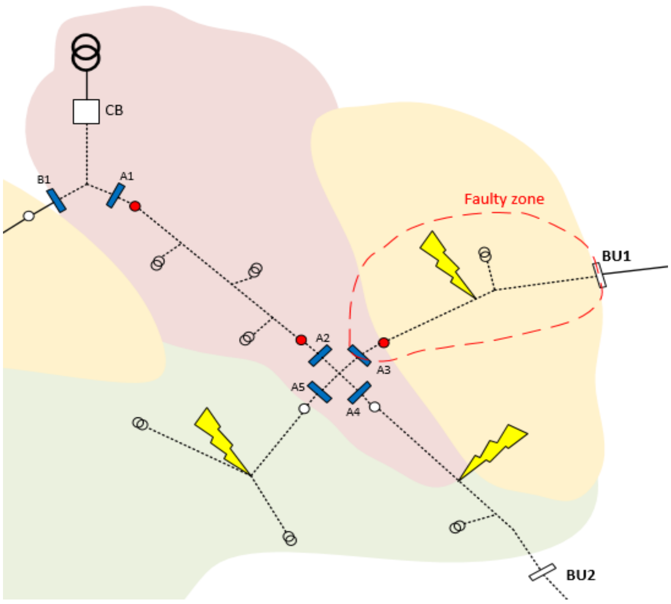

Figure 20. *Fault inference using fault detector operations. Estimated faulty zone is located between RCD A3 and BU1.*

Environmental factors, such as the placement of the conductor, height of the surrounding forest and weather data, can also be used to deduce the fault location. Especially during severe weather conditions, overhead lines are exposed to falling trees and tree branches due to high winds or heavy snow loads. [17] Information of the overhead lines located in the forest may not be solely efficient way to infer the fault location. Also, information of the surrounding forest maintenance and e.g. direction of the wind or amount of the snowfall must be used to weight the most fault prone line sections.

Figure 21 presents the situation where the fault indicator operations are not plausible. According to the calculated fault distances, a fault could exist in both branches behind disconnector A1 and B2. However, the overhead line behind disconnector B1 is usually more prone to faults than the underground cable behind disconnector A1. Therefore, the calculated fault location between disconnectors B3 and B5, where an overhead line is located in the forest, is the most prominent fault location.

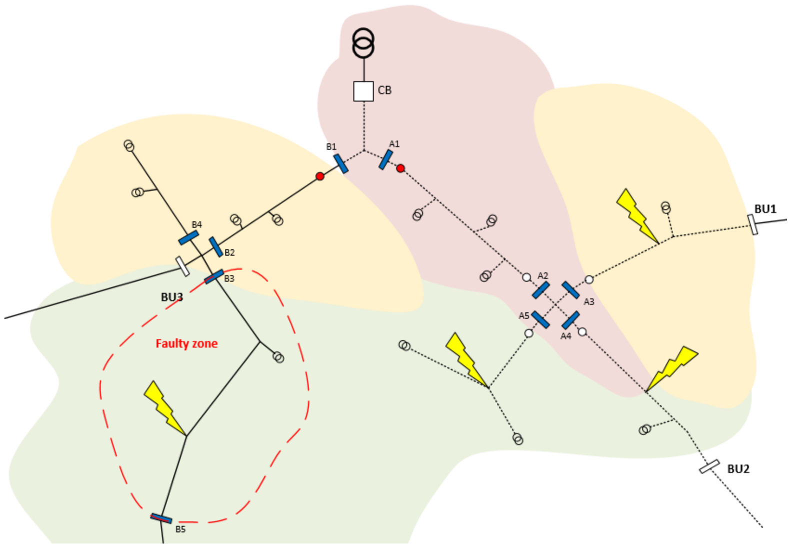

Figure 21. *Fault inference using environmental factors. Estimated faulty zone is located between RCD B3 and B5.*

Statistical fault history of the line sections can also be used as a data source for fault inference. Usually exact fault locations are documented during fault reporting or faulty disconnector zones can be approximately defined from the fault reports. [19] If a fault location has been in a certain disconnector zone multiple times, line sections of the disconnector zone can be marked as fault prone sections. Due to the changing conditions of the distribution network e.g. renovation and maintenance, this kind of a statistical history data should be updated when, for example, overhead line is replaced with an underground cable.

4.1.3 Trial switching

Experimental method of trial switching is commonly used in a traditional fault management as described in chapter 3.5. The trial switching method is utilized to locate the faulty disconnector zone if there are not enough variables to deduce the exact fault location or the fault location inference results more than one possible location. The principle of the trial switching is to divide the faulty feeder using disconnectors and close the substation circuit breaker against the suspected fault. If the circuit breaker trips, the fault is located between the CB and opened disconnector, otherwise the fault is located behind the opened disconnector. By these means, procedure is repeated until the fault is located to a single disconnector zone. After the fault is located and isolated with remote-controlled operations, operator continues the trial switching by dispatching field crews to operate manual disconnectors. [12] The effectivity of an automatic trial switching method relies on the number of RCDs along the feeder and the reliability of the communication [39].

In a **bi-section method**, faulted feeder is divided into approximately two equally sized zones. Division of the feeder can be based on the length of the feeder, the number of customers or type of the line sections. For example, a rural part consisting of overhead lines, in which fault probability is higher, can be separated from the section in a town plan area. After the disconnector is opened, the circuit breaker in the primary substation is closed against the suspected fault. If the circuit breaker stays closed, the fault is located behind the opened disconnector. The operator continues to divide the feeder into smaller sections until the fault is located between two remote controlled disconnectors. [12] A simplified example of bi-section method is presented in Figure 22.

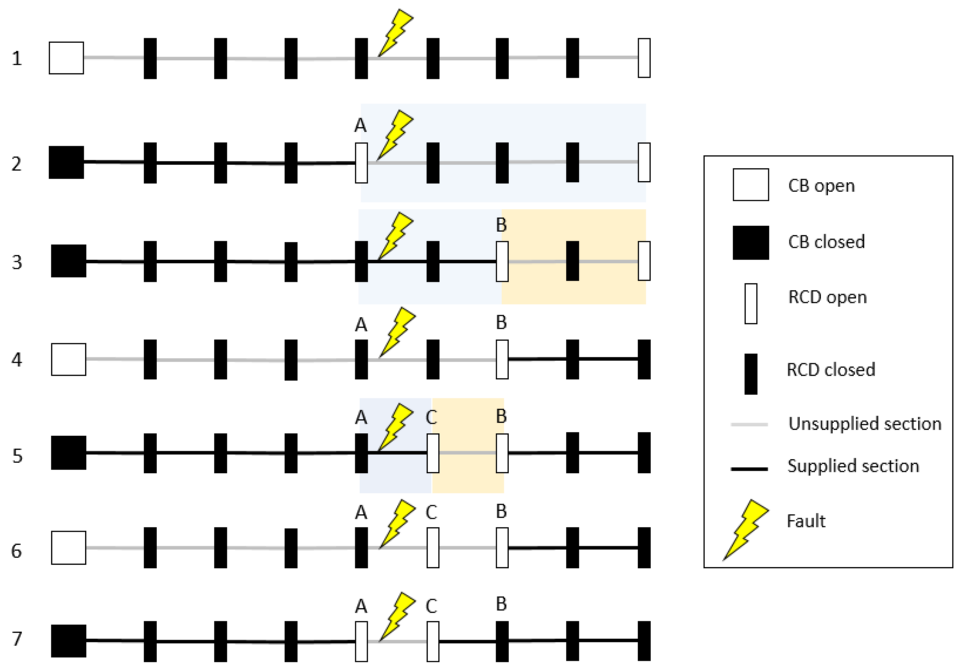

Figure 22. *Bi-section method in simplified feeder*

1. Circuit breaker trips due to permanent fault and the feeder is de-energized
2. Feeder is bisected using remote-controlled disconnector A and the circuit breaker stays closed. Fault is located behind the RCD A.
3. Suspected fault area is bisected using remote-controlled disconnector B and RCD A is closed.

4. Circuit breaker trips and fault can be located between RCDs A and B. Supply can be restored via backup connection from the end of the feeder.
5. Remote-controlled disconnector C dividing zone between A and B is opened. Circuit breaker is closed.
6. Circuit breaker trips and fault can be located between RCDs A and C.
7. Remote-controlled disconnector A is opened, and fault is isolated for operator to handle. Supply can be restored to RCD zone C – B using the backup connection.

Another method for trial switching is so called **zone-by-zone rolling** or step-by-step method. The basic principle of the zone-by-zone rolling is to energize the feeder one disconnector zone at a time. Usually all the RCDs of the faulted feeder are opened and then closed after another until the fault has been located. Likewise, in the bi-section method, the circuit breaker is closed against the suspected fault and the CB tripping indicates the faulty zone. Simplified zone-by-zone rolling method in straightforward feeder branch is described in the Figure 23.

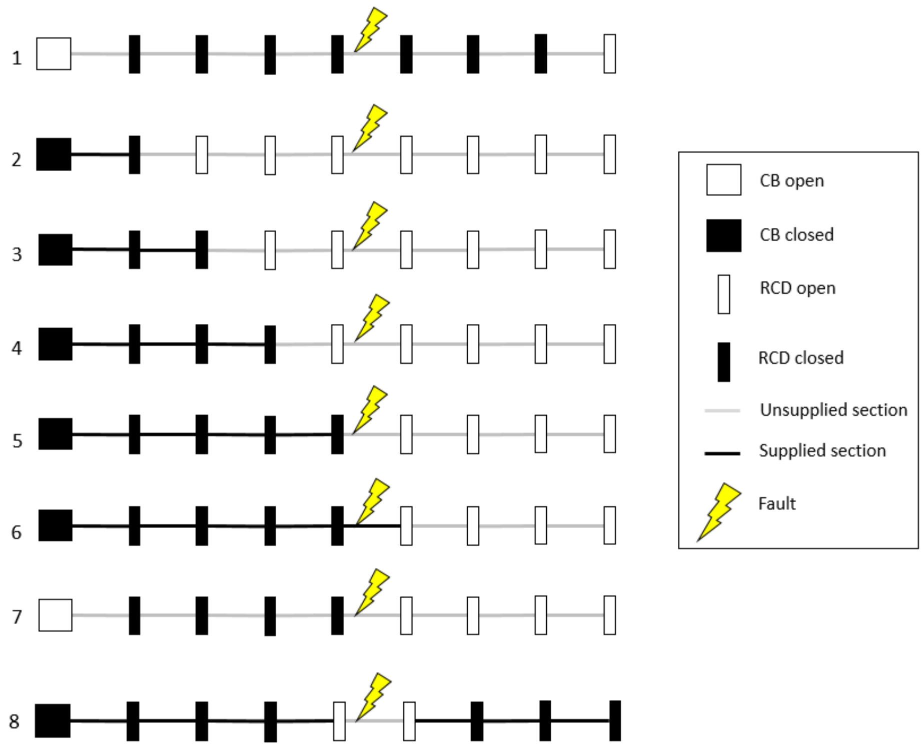

Figure 23. *Zone-by-zone rolling method*

1. Circuit breaker trips due to permanent fault and the feeder is de-energized. RCDs in the branch are opened.
2. – 6. Remote controlled disconnectors are closed one by one towards down-stream until the upstream RCD of faulty zone is closed.
7. Circuit breaker trips and fault is located.

8. Faulty zone is isolated, and supply can be restored to feeder upstream from the substation and feeder downstream using open backup connection.

Disadvantage of the zone-by-zone rolling method is its long execution time in case of a long branching feeder including multiple disconnector zones. On the other hand, number of unnecessary tripping of the circuit breaker can be reduced. [12] While the bi-section method is faster but can include more network straining tripping of the circuit breaker, one possible solution is to combine these two methods. The first coarse sequence is performed using the bi-section method, if there are RCDs available in the faulty zone. After the feeder bisection, the zone-by-zone method is applied until the fault is located to the one RCD zone. [39]

There are certain disadvantages in the trial switching method. In case of a short circuit fault, resupplying the faulty feeder against the fault causes thermal stress in the conductors and the circuit breaker. This is most harmful in the cabled network due to slow cooling time of the conductors. Therefore, number of trials must be limited or even disabled in some of the feeders. [41] Subsequent trial switching against the earth fault causes voltage strain between healthy phases and the ground. A single-phase earth fault can thereby develop into a cross-country earth fault and increase the extent of the faulty area. Overvoltage can also cause damage to network insulation and customer devices. [41] Also, the electrical safety of the working personnel along the network must be considered in the utilization of automatic trial switching. Operation of the trial switching sequence must be blocked to prevent re-energization when the field crew is operating in the faulty feeder near energized network equipment. [28]

4.2 Supply restoration

Even though distribution feeders are operated radially, the distribution network is built as meshed with open tie point switches. Tie point switches are used to optimize the distribution network load flow and to operate as a reserve connection in outage situations. After the fault has been located and isolated, the supply can be restored to the healthy parts of the feeder if possible. Depending on the location of the isolated RCD zone, parts of the feeder can be restored either from the upstream direction of the substation or via open backup connections from adjacent feeders. If a certain branch of the faulted feeder can be stated as un-faulted, supply may be restored even before the complete fault isolation to minimize outage costs. When the trial switching sequence is used, restored branches must still be isolated from the main supply route between the fault and the substation to avoid unnecessary short breaks. [15]

In automatic supply restoration, the DMS can be used to check possible constraint violations for each of the backup connections. The load flow calculation ensures that the maximum loading capacity of the adjacent feeder is not exceeded, and voltage drop stays in desired limits. Also, the network protection of the adjacent feeder must stay functional after the restored area is connected. The DMS calculates the lowest short-circuit current as well as earth fault currents and compares them to the relay settings. constraint violations are detected, the backup connection cannot be used in supply restoration. [9] Usually in normal operating conditions, the network is planned to withstand the effect of load transfer between the feeders, but violations may still occur during high load situations and when the network switching state differs from normal due to e.g. a major disturbance situation. [47]

Advanced distribution automation and increasing degree of distributed energy resources (DER) will provide possibilities to support load balancing between feeders in supply restoration. In some cases, DER may even operate a feeder branch in islanded mode when backup connections are not available. [48] In terms of a backup supply, DG can be divided into two categories according to operation modes: BDG (Black-start DG) and NBDG (Non-Black-start DG). The BDG can be used as parallel with the supplying distribution grid to support the backup connection, or in islanded operation mode. The NBDG is only capable of parallel support without the island operation. The black-start capable DG usually includes an energy storage combined with the generation unit to act as a complement in short power gaps, especially in solar and wind power solutions. [49]

Modern microprocessor-based relays often include an option for remote-configuration or parallel configuration settings. These functionalities with improved communication architecture can be used to change the fault current settings and tripping delays during unusual switching conditions. [15] Reconfiguration of a single feeder terminal, in most cases, requires also reconfiguration of adjacent feeder terminals and upstream substation relay to maintain selectivity of the protection. Challenging coordination between multi-level protection may lead to safety issues and network equipment failures in case of a setting error. Also increasing penetration of distributed generation complicates coordination of protection as described in the chapter 3.6. Therefore, automatic reconfiguration of protection is not the preferred method, at least with current state of the network automation and communication infrastructure. [15, 35] Figure 24 presents the conceptual model of the DER and protection coordination utilized in the supply restoration.

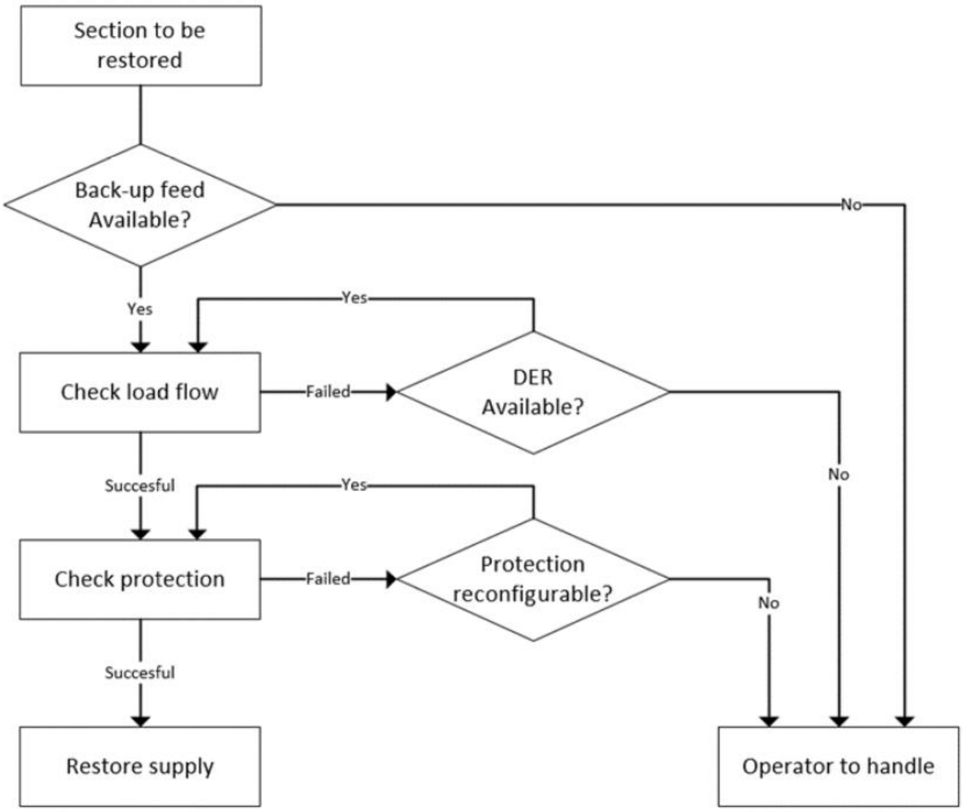

Figure 24. *Supply restoration scheme including DER and protection reconfiguration*

Besides technical limitations, an adjacent feeder may not be suitable for a backup connection due to important customers or a high number of customers. Even when the fault is automatically isolated, there is still a chance of malfunction in the fault isolation logic or multiple faults occurring on the same feeder. Especially during severe weather conditions, several trees may be leaning against the overhead line causing multiple faults. If another fault occurs in the downstream of the isolated RCD zone, automatic isolation sequence is not able to detect that. When supply is tried to restore to the downstream section, the adjacent feeder also trips, and extent of the outage area increases. [50]

5. MICROSCADA PRO

The MicroSCADA Pro is a product family for controlling and monitoring electricity networks, made by ABB. Product portfolio of consists the SYS600 and the DMS600. SYS600 is the SCADA system, used for real-time monitoring and controlling of the primary and secondary equipment in the network. DMS600 is the distribution management system, which consists of two main applications: DMS600 Network Editor (NE) and DMS600 Workstation (WS). DMS600 applications run in Microsoft Windows or Server operating systems using Windows Service based add-ins and SQL database to communicate with SYS600 and external interfaces. [51] Communications between the applications are visualized in Figure 25.

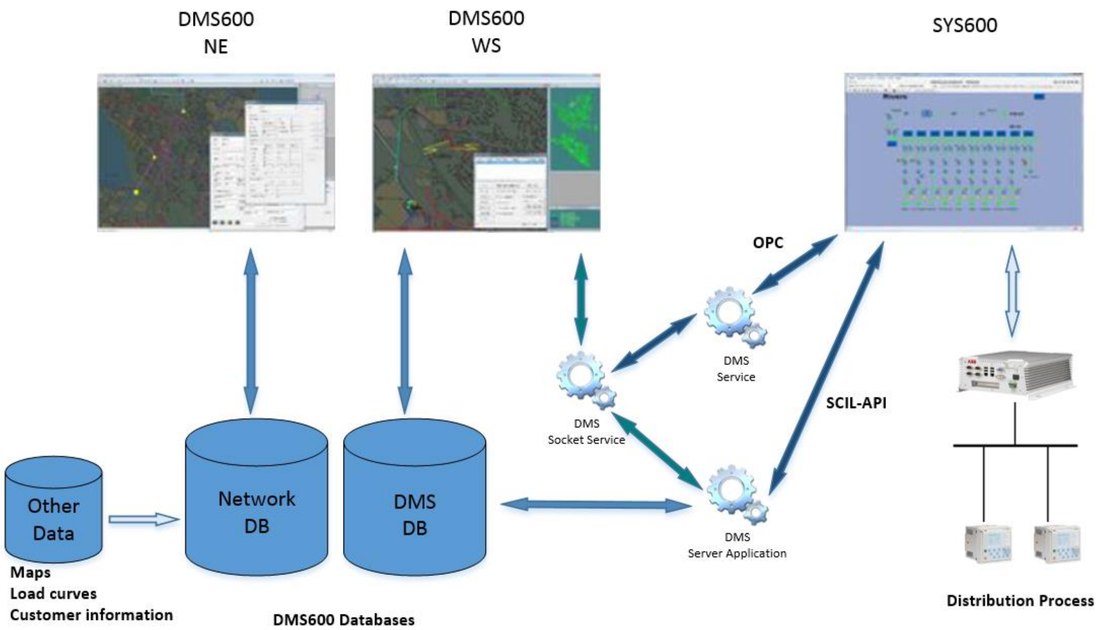

Figure 25. *Communication between MicroSCADA Pro applications.*

MicroSCADA Pro applications can also be used with systems from other vendors. For example, DMS600 WS is widely used with Tieto PowerGrid (PG) or Tieto Smart Utility network information systems and the SCADA systems from other suppliers. Network information can be imported with a transfer file or with an external Network Import Tool module, which writes information directly to the SQL database. In addition, a network model can be imported from the GIS (Graphical Information System) database with the Network Import Tool module. Automated import methods reduce the workload of the DSO since only one network model has to be maintained.

The integration between DMS600 and SYS600 is implemented using OPC Data Access (OPC DA) communication standard or the ABB specific SCIL-API. Besides SYS600, it is possible to use SCADA system from other vendors, if only the OPC communication is available. Therefore, SCADA system using ELCOM-90 or IEC-104 as a communication standard needs SYS600 to handle the communication with the WS. As introduced in the Figure 25. DMS600 includes three background services for internal and external communication: DMS Socket Service, DMS600 Server Application and DMSService Framework. [51] The DMS Socket Service handles the internal TCP/IP messaging between DMS600 instances and the background services. The DMS600 Server Application (DMS600 SA) is used for establishing connection and managing the data transfer between MicroSCADA and WS, when the SCIL-API is used. [51]

The DMSService Framework consists of monitoring application and several modules for internal communications and scheduled tasks as well as interface for 3rd party applications. [52] The OPC Client is responsible of the communication between DMS600 and the SCADA. Because of the OPC Client, DMS600 can be used with any SCADA system that supports OPC DA standard. Also, with the SYS600, OPC has become the preferred method of communication and SCIL-API is rarely used. The OPC connection requires mapping between SCADA process points and remote-controlled devices documented in the DMS. [52]

5.1 MicroSCADA Pro SYS600

MicroSCADA Pro SYS600 interacts with the distribution process via process database that consists of linked process points to the control and monitoring devices. Information gathered into the process database can be then visualized in the: Process display, Trends display, Event display, Alarm display and Measurement reports. The communication between the SYS600 and the RTUs and IEDs in the primary process can be implemented with common protocols such as IEC 61850, Modbus, SPA and LON. [53] The information flow of the SYS600 is visualized in Figure 26.

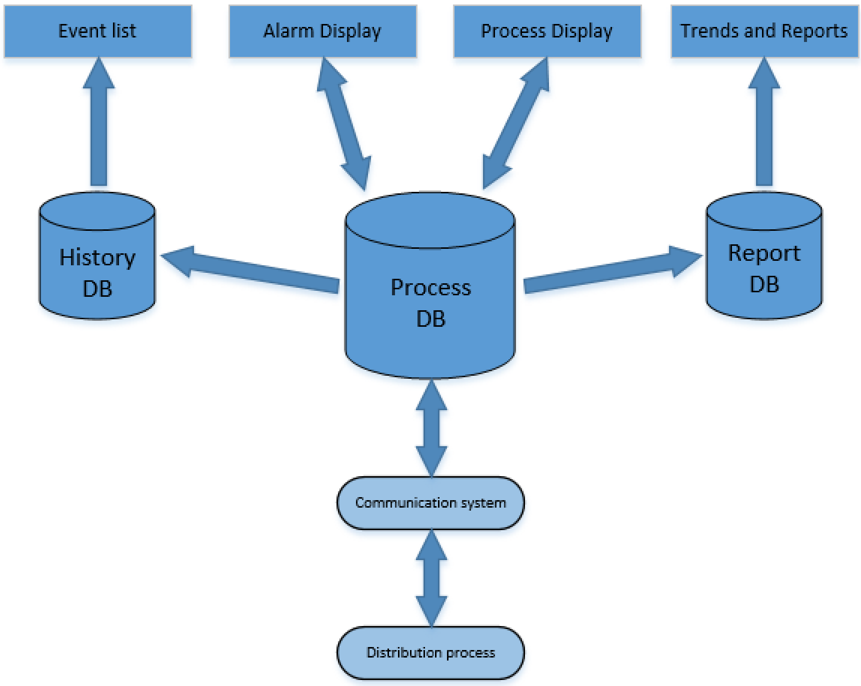

Figure 26. *Information flow of the SYS600 adapted from [53]*

The process display presents the topology of the network and allows operator to control the switching devices. The SYS600 application usually consists of several smaller process displays including one primary substation and the overview display to present simplified schematic topology of the network. The overview process display of the SYS600 demo application is presented in Figure 27. In addition to the switching components and transformers, the primary substation display typically includes the most important measurements and alarm indications. The process display can also be used to monitor the status of the system itself. [53]

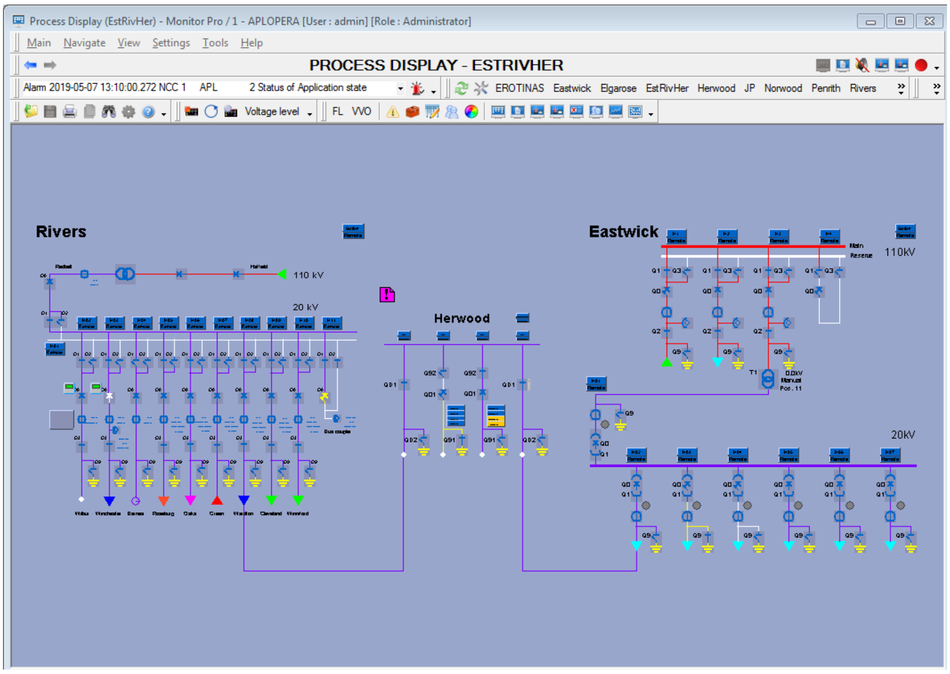

Figure 27. *Process display of the SYS600 including multiple substations*

Along with the process display, it is possible to show a list of all events and alarms of the system in Event and Alarm displays. The trends display and the measurement reports can be used to present the measured values, such as energy, voltage, current or protection device operations, as graphs or numerical tables. That allows the operator to analyze, for example, power quality and the root cause of the disturbance. [53]

5.2 MicroSCADA Pro DMS600

The DMS600 consists of two main applications: Network Editor (DMS600 NE) and Workstation (DMS600 WS). The Network Editor is used to maintain the network information and carry out administrative tasks, such as management of the integration between SYS600 and DMS600 and common settings of the DMS600 application. Because of the scope of this thesis, only the DMS600 WS is introduced more precisely focusing on the functionalities used in automatic fault management. The Workstation is an application for controlling and monitoring the distribution network. It utilizes the network information documented with the Network Editor or imported from external network information system along with switching state and measurement information received from the SCADA system. [51]

Typically, DMS600 WS includes a geographical topology presentation on a background map with embedded substation diagrams. Additionally, the network view can be presented as a schematic view to simplify the visual presentation. GUI of the Workstation also includes an Auxiliary Network Window, which shows an overview of the whole network, Connection Status bar to visualize the connection statuses with color indications as well as legends for symbols and network coloring. If the connection to SYS600 is established, process displays and SYS600 Switch Control dialogs can be opened and operated from the WS. [11] GUI of the DMS600 demo application is shown in the Figure 28.

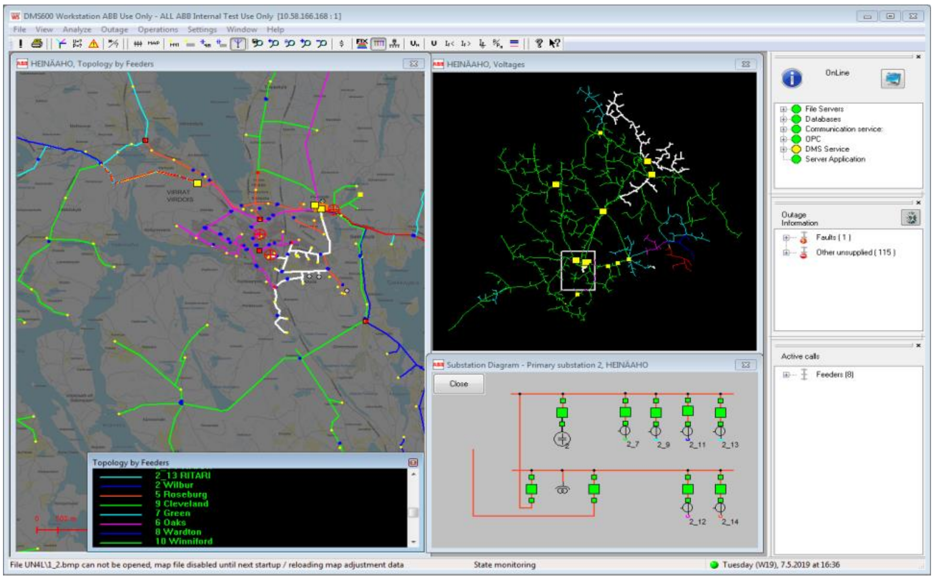

Figure 28. *The GUI of the DMS600 Workstation*

When operated in the real-time state monitoring mode, the network analysis is carried out automatically in the background and topology is updated by switching state information received from SCADA. To achieve enhanced performance during major disturbance situation, a disturbance mode that disables certain functions of the WS, such as automatic fault location and load flow calculation, can be used. DMS600 WS can also be used in a simulation mode, which disables the control to the real-time system allowing the operator to analyze various switching states or examine already handled fault situations. Switching actions and simulation settings, such as modified relay data or load forecasts, are saved only to the current instance of the DMS600 WS. [11]

DMS600 WS includes several functionalities to visualize and analyze the distribution network. Geographical model of the distribution network, including manual switching devices and secondary substations, connects primary substations and remote-controlled devices into an overall topology model. Therefore, operator or automation can manage and optimize the switching state of the whole network efficiently. DMS600 WS also includes a network load flow and protection analysis to detect potential constraint violations during e.g. high load situations and network reconfiguration. A switching planning functionality allows pre-made switching sequences to be made or automatically generated for the maintenance outage process. [11]

DMS600 includes variety of functionalities in fault management for medium voltage and low voltage networks. The MV fault management consists of visualizing the faulty feeder in the network view with calculated fault distances, if relay measurements are available. If fault can be definitely located into a certain disconnector zone, line sections are highlighted in the feeder topology. Fault are operated from the fault management dialog, which is automatically opened when permanent fault indication has been received from the SCADA. Outage information tab shows all outages occurring in the distribution area with detailed information about e.g. count of customers and LV networks affected and outage durations. [11]

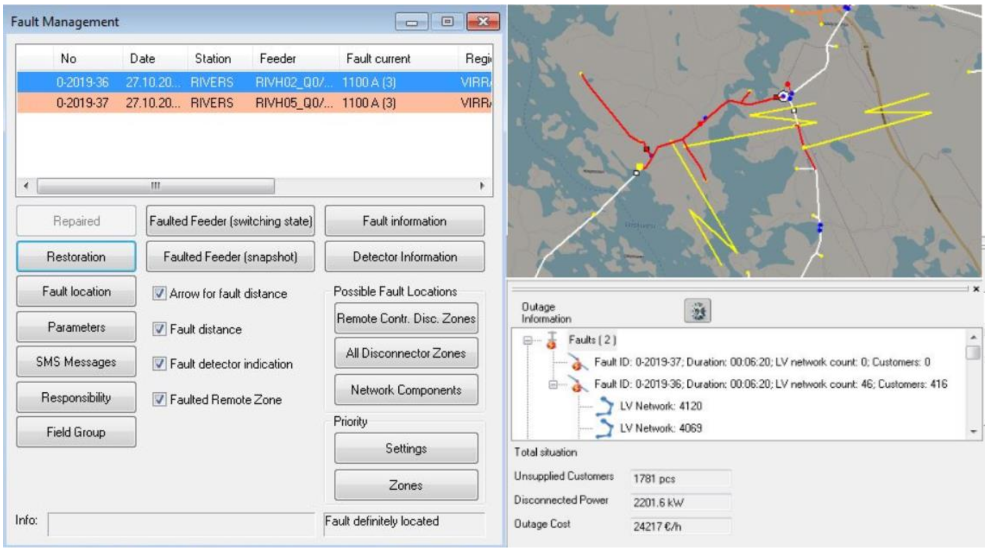

Figure 29. *Fault Management dialog, fault distance indication and Outage Information tab of DMS600 WS*

Multiple faults can be handled at the same time with separate DMS600 WS applications. Operator can take the responsibility of a certain fault from the fault management dialog and start the fault isolation process using the fault distance and inference information provided. More detailed information of the fault can also be observed and modified afterwards for simulation purposes. After the fault has been repaired, operator can proceed into a fault reporting. DMS600 WS automatically generates an outage report template based on the executed switching sequence and calculates the key values according the network data.

Fault management of DMS600 WS consists also several other functionalities, but due to the scope of this thesis, only the fault location, isolation and restoration functionalities are introduced in detail. Besides aforementioned functions, DMS600 fault management consists of reporting and archiving for MV and LV network outages, field crew management, outage prioritization based on outage costs and critical customers, management of customer calls and interface for automatic meter reading system. Also, automatic customer notification by SMS messages and web-based outage info map can be achieved with an external interface.

5.2.1 Fault detection and location

The fault location functionality of DMS600 Workstation can be used to determine an exact fault location along the feeder by fault distance calculation, or faulty disconnector zone based on fault detector operations and fault inference according to the conductor types and overloading network components. The fault location function can handle permanent feeder faults in radial operated feeders in neutral isolated, compensated or neutral earthed distribution networks. Generators feeding relatively small short circuit currents can be reduced to simplify the fault distance calculation.

When the permanent fault has occurred, available fault data and fault detector operations are sent from SCADA to DMS600 WS. Position indication of the substation circuit breaker and fault indicator operations are sent from the SCADA OPC Server to DMS600 WS through OPC Client of the DMS Service framework. The fault data is then applied with Fault Service module that creates a fault package containing gathered information. The process flow of the fault creation is presented in the Figure 30.

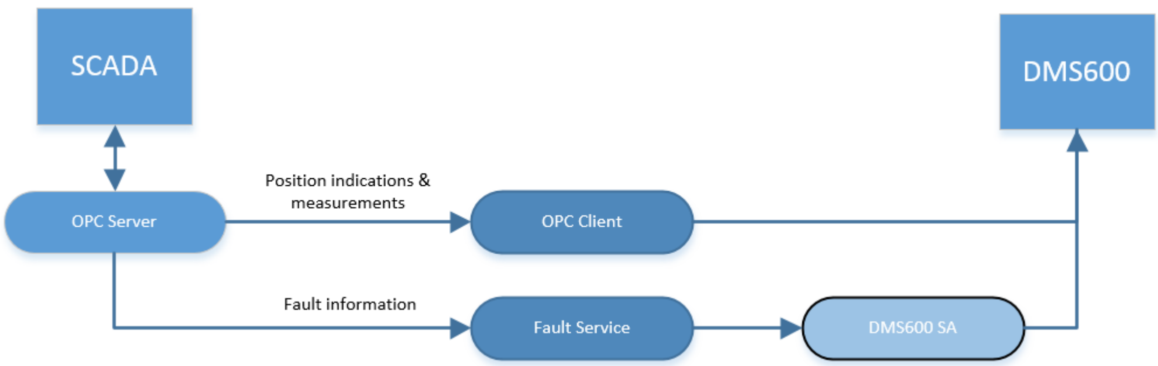

Figure 30. *Process flow of the fault information between SCADA and DMS600 WS*

Process points of the feeder terminal trip and measurement signals must be attached to the corresponding signal definitions of the Fault Service by a configuration tool. Keeping Fault Service configuration up to date is essential for the fault location functionality. For example, there have been situations where the fault current measurements have not been received, or the fault package have not been created due to configuration errors. Occasionally the lack of fault current measurements may depend on the communication errors or delays with protection devices, RTU and SCADA. [54] Fault Service is configurable by the means of delaying the fault package creation to wait delayed measurements, but usually DSOs require fault to be established immediately to achieve real-time customer notification [19]. Effectivity of the fault package creation should be improved by updating the information of existing fault after the establishment.

After the fault has been established in DMS600 WS, fault distance calculation is performed automatically. As presented in the Figure 29, if the measurements are plausible calculated fault distances are visualized in the faulty feeder by bolt symbols. Distribution feeder usually includes multiple branches having equal electrical distances and there may be several distance calculations available. This might be helpful guidance to the operator deducing the fault location but challenging for automation to handle. Besides fault distance calculation, on-site and remote-readable fault indicators can be used to determine the faulty branch or disconnector zone. Fault distance and fault indicator operations along with conductor type and overloading components are used by the fault inference logic of DMS600 WS that is based on fuzzy sets introduced in chapter 4.1.2. DMS600 WS calculates the likelihood of a fault for each disconnector zone as presented in the Figure 31.

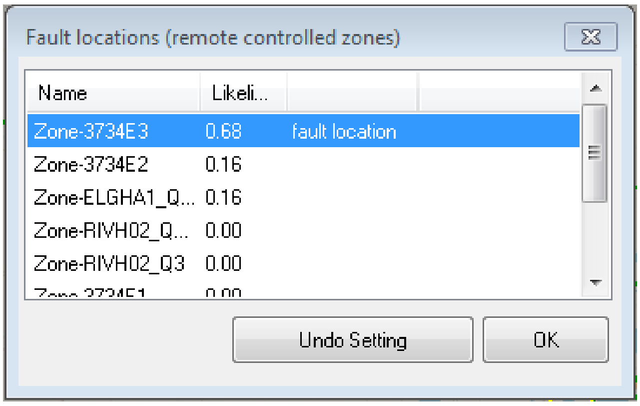

Figure 31. *Fuzzy logic calculated fault likelihoods for RCD zones*

Determination of the faulty zone depends on the limits set by the user. Likelihood limit settings require the minimum limit for a faulted zone and the maximum limit for healthy zones. [11] In the example above, minimum limit for faulty zone is set to 0.5 and maximum limit for healthy zone is set to 0.3. Therefore, zone with a likelihood of 0.68 is defined as the faulty RCD zone and rest of the zones having likelihood below 0.16 as healthy zones. Fault location limits and certainty factors for fuzzy sets must be carefully set according to the prevailing situations. For example, overhead line is more prone to fault during high winds and heavy snow loads, or fault indicator operations may be incorrect during thunderstorm. [12]

5.2.2 Automatic fault isolation and restoration

The current automatic fault isolation and restoration mode of DMS600 WS requires faulty remote-controlled zone to be determined with the fault inference logic. If the faulty zone cannot be determined, execution of the automatic sequence is stopped, and fault is handed over to the operator. When a single faulty RCD zone is determined, fault isolation and restoration planning generates a switching sequence to isolate the faulty zone and to restore healthy feeders using backup connections or supply from the feeder upstream. The sequence takes into account the technical constraints and the protection of the network [11]:

- Voltage drop
- Short-circuit capacity and load level
- Short-circuit and earth fault detection

If technical constraints are fulfilled and the switching sequence is successfully created, isolation and restoration sequence can be either started automatically or after operator's confirmation. Created switching sequence is sent to MicroSCADA, which checks the controllability of the switching devices. If errors in operability of switching devices are detected, MicroSCADA rejects the sequence and requests a new sequence to be made excluding the un-controllable devices. After the switching sequence has been confirmed as successful, MicroSCADA starts the execution step by step. Before each step, switching state of the feeder is checked to correspond the switching plan. If switching states differ or MicroSCADA is not able to carry out the switching action, e.g. due to communication error, automatic fault isolation and restoration is interrupted, and it must be manually restarted. [11] The process flow diagram of the current automatic fault isolation and restoration mode is presented in the Appendix A.

In the version 4.5 of the DMS600 WS, fault restoration logic will be enhanced by restoring the supply to all remote zones where the fault does not definitely exist. This is achieved by combining the most likely faulty zones and checking if rest of the RCD zones can be restored via backup connections or from the feeding substation. Fault management dialog also includes a Restoration plan dialog, which operator can use to create sequence using either remote-controlled or manual switching devices when the fault location is known. Restoration plan dialog can also be used to create switching sequence to return to the switching state before the fault, or to the normal switching state of the distribution network. [55]

6. INTERVIEWS FOR DISTRIBUTION SYSTEM OPERATORS

An interview for Finnish distribution system operators was implemented to gather comprehensive knowledge on fault isolation and supply restoration process carried out by human operators. Thus, a more human-like operation, most desired features and possible restrictions could be implemented on the FLIR algorithm. Interviewed DSOs presented in Figure 32 were:

- Savon Voima Verkko Oy (highlighted with blue)
- Kajave Oy (highlighted with green)
- Koilis-Satakunnan Sähkö Oy (highlighted with purple)

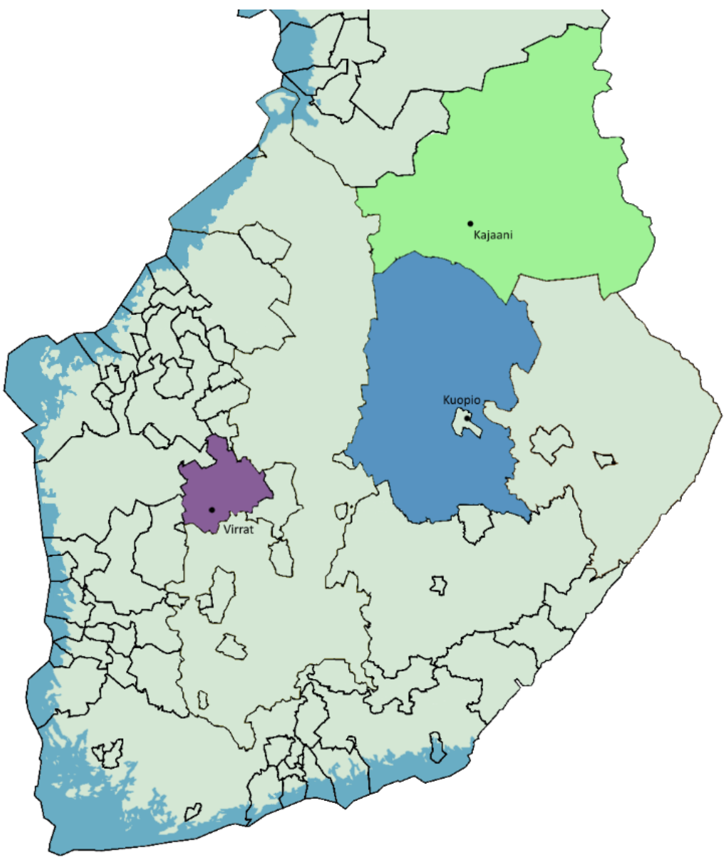

Figure 32. *Distribution areas of the interviewed DSOs*

The inquiry was carried out with semi-structured interviews where the basic structure of the questionnaire was sent to DSOs in advance. Thus, the representatives of the DSO were able to delve into the subject, and limited interview time could be utilized more efficiently. With semi-structured interview, meetings could be carried out rather open conversation, so as much as operators own knowledge and experience could be gathered. The questionnaire, presented in Appendix B, consists of topics:

- General information about the network and methods to increase the distribution reliability
- Required features and restrictions according to the automatic fault location, isolation and supply restoration
- Fault isolation and restoration process performed by the operator
- The most important features to be implemented in the DMS600 WS

Interviewed DSOs were selected based on already known demand for the FLIR functionality and variety of the SCADA and DMS system combinations in use. For the objective of this thesis, all the studied distribution system operators were operating mostly in rural network areas, where the demand for a centralized FLIR solution is greater. Interviews were carried out in the premises of the DSO that created also an opportunity to see the NCC operation in action. The meetings were recorded and transcribed afterwards. Representatives of the DSO were informed if interview contains confidential information that cannot be published in this thesis.

6.1 Savon Voima Verkko Oy

Savon Voima Verkko Oy (SVV) is a DSO operating in the Northern Savonia region. SVV is a subsidiary of Savon Voima Oyj having operations also in electricity generation and district heating. Electricity sales and energy services are operated by Väre Energia Oy, a nationwide joint company formed by Savon Voima, Jyväskylän Energia, and Kuopion Energia. [56] According to the Energy Authority, during year 2018 SVV distributed electricity to over 117 000 household and industry customers [57]. As a distribution management system SVV uses MicroSCADA Pro DMS600 Workstation. Alongside the DMS600 WS, SVV is using Tieto Smart Utility network information system (TSU-NIS) and MicroSCADA Pro SYS600 as a SCADA system. [58] The distribution area according to the web outage map is presented in Figure 33.

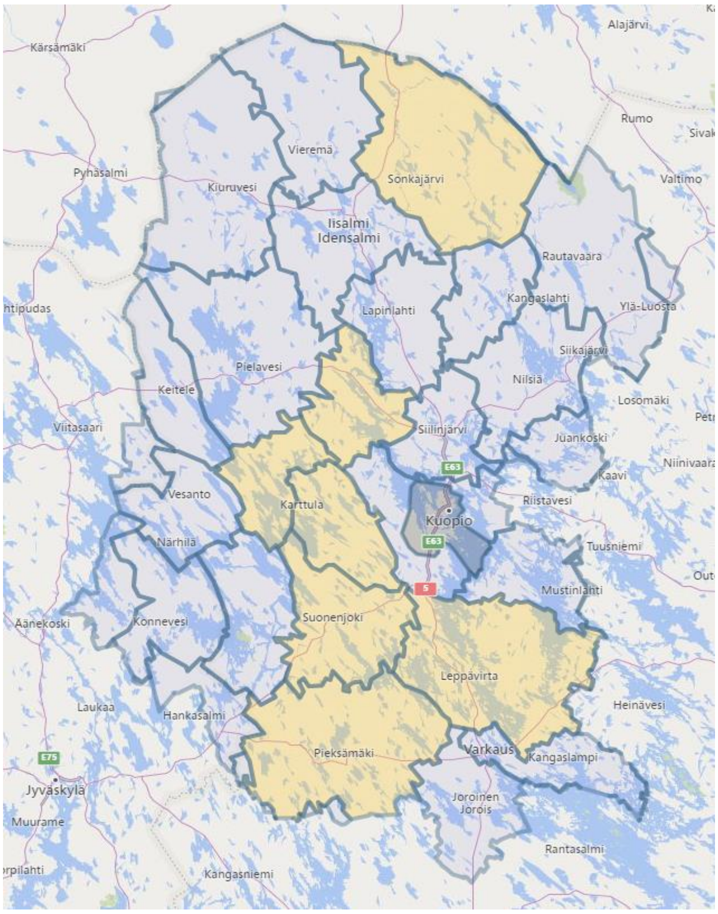

Figure 33. *Distribution are of SVV according to the outage info map presentation [59]*

Total length of the distribution network is almost 27 000 km, of which about 12 000 km is MV network. SVV operates also approximately 520 km of regional 110 kV transmission network. According to the statistics of 2018, cabling rate of the MV network was 13.1 % and 37,9 % in the LV network. There are 43 primary substations with over 300 feeders and approximately 1 900 remote-controlled disconnectors installed in the distribution network of SVV. The distribution area of SVV is highly forested and thus prone to fault especially during severe weather conditions. [53]

To meet the distribution reliability requirements, SVV is utilizing variety of resources. Besides replacing overhead lines with cables, an overhead line is also installed beside roads and nearby forest is maintained. 1 kV network solutions and an increasing amount of network automation, such as remote-controlled disconnector stations and reclosers, are also considered to enhance the distribution reliability especially in rural feeders. Interviewees noted that not all of the distribution network will be cabled due to high investment costs, but existing and upcoming network automation will be utilized more efficiently, and the overall fault management process will be enhanced.

SVV had a pilot project of deploying advanced secondary substation automation with a reactive power compensation and fault indicators. Fault indicators were discovered to be unreliable in both short-circuit and earth fault situation. It was also noted that a compensation device installed in the same substation with fault indicator made the fault indicator operation even more unreliable. Utilization of distributed energy resources is not yet considered as a part of supply restoration, since distribution network operator is not allowed to own DER units. Some of the hydropower units of the distribution area can be operated in islanded mode, but current level of automation does not support automatic use. [58]

Due to the varying conditions and fault situations, SVV does not have strict guidelines for handling an individual fault besides electrical safety and technical limits. According to the interviewees, there are some variations on how the operator locates and isolates the fault. For example, when there is no information to locate the fault, operators are using their intuition or knowledge of the environmental conditions to perform the first trial switching action. While there are multiple sources of open data, e.g. forest height, and wind speed and direction, the operator does not have time to analyse that during the fault situation, but instead the management of the data should be automatic and visualized properly in the network view of the DMS. [58]

According to the interviewees, the automatic fault location of the DMS600 only performs accurately in rather simple overhead line feeders in case of the short-circuit fault. However, the fault current measurement is not always available due to communication or configuration errors of the relays. Therefore, the only option for locating the fault is to perform trial switchings or receive the fault location through an external inspection, e.g. a customer call or helicopter inspection. The method of experimental switching is also varying among the operators. Usually the faster bi-section method is used for the first trial switching, but zone-by-zone rolling method is also used for example with shorter feeders. [58]

Current implementation of the automatic fault isolation and supply restoration of the DMS600 is not feasible enough according to the SVV representatives. All the interviewees agreed that automation may perform switching actions and restore supply independently. When automation is used, electrical safety must be ensured carefully and execution of the FLIR sequence must be stopped in potentially dangerous situation. There should also be clear indication of operations, which automation has performed and if FLIR sequence has been stopped by an error. Representatives noted that SVV has over 300 feeders and therefore single FLIR instance is not efficient enough to handle multiple fault situations. FLIR should be able to operate multiple faults simultaneously, for example in the separate fault handling areas, so switching actions do not overlap. [58]

Even though trial switchings must be implemented in the system, the initial data from the relay and fault indicators should also be used to determine possible fault area. Representatives stated that fault inference according to the measurements and fault indications should be the primary method to narrow down the faulted feeder and to reduce unwanted trial switchings. The trial switching sequence should first use the bi-section method to roughly divide the feeder by expected customer outage costs. After the coarse bi-section, rest of the faulty area is located and isolated using the zone-by-zone rolling method. FLIR should be able to handle multiple faults occurring in the same feeder. If the circuit breaker trips even after the first RCD zone has been isolated by zone-by-zone rolling, FLIR should not stop as a malfunction. Instead the second faulted zone should be located and isolated by the means of zone-by-zone rolling. [58]

Usually the operator also verifies the existence of the fault by performing the last trial switching against the suspected fault zone, but again it is dependent on the magnitude of the fault current and weather conditions. For example, when three-phase short circuit fault is located near the substation, high magnitude fault current can cause voltage dip also in the adjacent feeders or forest fire in dry season. In these situations, the operator usually avoids closing the circuit breaker for verification. [58] To avoid aforementioned problems, the last trial should be optional in the feeder level FLIR settings.

Representatives proposed that after the automation has isolated the faulty RCD zone, assisting manual switching sequence would be useful. Usually one RCD zone can include multiple manual disconnectors and the optimal switching sequence could be created with applying the fault inference on the isolated RCD zone. As the isolated remote zone covers remarkably smaller area, continuous fault inference could provide more accurate results. Also, optimal manual switching sequence would be beneficial, after the exact fault location has been received by a customer call or e.g. helicopter inspection. [58]

The basic principle of the fault clearing process is to locate and isolate the fault before restoring the supply to avoid any unnecessary short breaks. Workflow of the whole process is mentioned to be more straightforward by these means. However, if specific branches can be certainly stated as unfaulty and isolated from the main supply route during the isolation process, supply is restored via backup connections. Usually there are no restrictions to use adjacent feeder as a backup supply, but operator is using careful consideration e.g. in severe weather conditions when urban feeder is used to supply a rural overhead line branch. There are also important industrial feeders, which are not allowed to use as a backup supply in the normal operating conditions. Therefore, a feeder level option to block usage as a backup supply should be included in the FLIR settings. [58]

According to the interviewees, automation would be most beneficial during night-time when a single remote operator is responsible of the network operation. There have been situations when a certain fault has not been noticed by the remote operator. Comprehensive situation awareness was mentioned to be crucial especially in a major disturbance. It was noted that during a major disturbance the network control center is manned full time and automatic switching actions could even disturb the operation and weaken the awareness of overall situation. FLIR could assist the operation by restoring only the weather-proof cabled network and then leave the fault for the operator. Hence, the operator has more time to analyse possible fault locations while automation performs the first actions. To obtain situational awareness, clear instructions of the performed switching actions should be provided to ensure seamless takeover for the operator. [58]

Besides the FLIR functionality, SVV representatives noted that an external tool or report for visualizing the overall situation would be useful in a daily network operation and especially in the major disturbance situation. Therefore, the overall situation according to the outages and the overall fault management process could be more easily shared between the NCC personnel and the management level the DSO. It was proposed that the report could visualize the total unconnected power and expected outage costs as a graph and forecast the upcoming situation according to the repair estimations set by operators and field crews. Additionally, all outages should be listed with real-time information of the fault clearing status, or if certain fault are not assigned to any operator or field crew. [58]

6.2 Kajave Oy

In 2018 Kajave, former Loiste Sähköverkko Oy, distributed electricity to about 58 400 customers in the Kainuu Region. Kajave Oy is a distribution system operator of Loiste Group, having also operations in electricity generation, district heating, and electricity sales. The network control center of Kajave is located in the city of Kajaani. [60] Total length of the distribution network is approximately 13 000 km, of which about 3 400 km is medium voltage network. Kajave also operates 245 kilometers of 110 kV regional transmission network. Cabling rate of the MV network is 9,1 % and 47,7 % in the LV network according to the 2018 statistics. Kajave has 654 remote-controlled disconnectors installed, which is approximately 19 RCDs per 100 km of MV network. [57] Distribution network area of Kajave Oy according to the web outage map is presented in Figure 34.

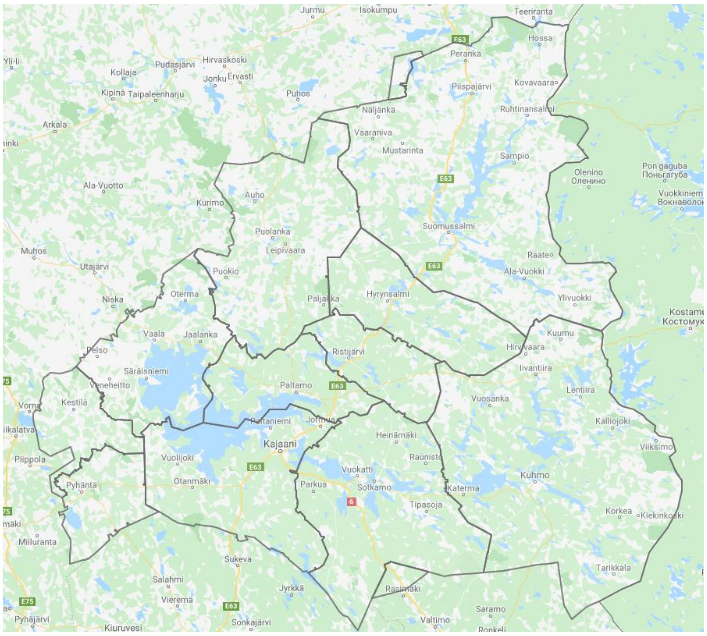

Figure 34. *Distribution area of Kajave according to the outage map presentation [61]*

Kajave differs from other interviewees having a distribution management system provided by Trimble also including Trimble network information system. As a SCADA system, Kajave uses the ABB MicroSCADA Pro SYS600. Kajave already uses the FLIR functionality developed through cooperation of Trimble and Netcontrol, in which ABB has implemented a FLIR interface to connect Trimble DMS to SYS600. [62]

The main target for enhancing the distribution reliability in Kajave is renovating the network by cabling, but also the amount of network automation will be significantly increased. Due to heavy snow loads that occurred in recent years, remote-controlled disconnector stations and reclosers will be installed especially for long, rural feeders. Besides increasing the amount of cabling and automation, overhead lines have been relocated to road shoulders, and overhead line routes are maintained as wood-proof. Kajave has also one disconnector station in 10 kV cabled network equipped with fault indicators, but no user experience has been acquired since no faults have been occurred in that feeder after the installation. According to the interviewees, reliable fault indicators would remarkably improve operation of the FLIR, leaving unnecessary trial switching to a minimum. [62]

According to the interview, fault location and isolation process of the network control center operator varies by the situation, and therefore no exact guidelines besides electrical safety and technical limitations can be determined. It was emphasized that the operators' experience speeds up the process, but with guidance of the DMS, an unexperienced operator should also be able to operate rather efficiently. The primary information used by the operator is the fault distance calculation performed by the DMS, but fault current measurements are not always available, or they may be incorrect. Potential fault-prone areas are not documented in the system, but operator's knowledge of such areas can be helpful when the initial data is not available for fault inference. Representatives noted that also AMR alarms are used to deduce the conductor failure in MV network, when the relay has not tripped. [62]

When performing the supply restoration, limitations of the back-feed capability according to the short-circuit protection are documented in the SCADA pictures to support the operator. If multiple backup connections are available, the most capable connection is used. It was noted that due increasing amount of underground cables, compensation of the earth fault current must be considered. If compensation is handled with distributed compensation coils in secondary substations, earth fault current compensation may not be able to support additional section to be supplied. Whereas, the compensation is handled with automatically adjusting centralized compensation coil in the substation, limits of the control unit must be considered.

Unlike other interviewed DSOs, Kajave has a FLIR functionality in daily use. FLIR solution is a part of the Trimble DMS and it uses a web service to communicate with MicroSCADA Pro SYS600. [39] The SCADA side functionality is implemented by ABB. The automatic fault location, isolation, and supply restoration of Trimble utilizes a trial switching sequence to support the fault distance calculation. FLIR was noted to be the most beneficial during nighttime, since the operation is taken care remotely at home. By these means, FLIR sequence can isolate the fault and re-supply healthy zones before the operator has set up the remote system. According to the interview, an average FLIR sequence takes approximately 4 minutes, but an experienced operator can perform the isolation and supply restoration even faster. Therefore, faults during office hours are preferred to handle by the network control center operators.

The FLIR functionality utilizes the fault distance calculation as the primary method for fault location. Before the isolation sequence, the first trial switching can be made to ensure that fault still occurs in the feeder. The first trial is performed after user defined time delay as the final trip of the circuit breaker happens. Thus, the auto-reclosing sequence have already been conducted, and the first trial acts as an additional auto-reclosing. According to the Kajave, high number of faults have been cleared during the time delay between final trip and the first trial switching. By these means, time consuming fault isolation sequence can be avoided, and the total outage duration stays under the limit of a short outage. [62] If the faulted zone cannot be deduced, FLIR proceeds into a sparse roll sequence to roughly determine the faulty area and continues with more precise dense roll sequence to isolate the fault in one RCD zone. Whereas one RCD zone can be determined as the suspected fault zone, FLIR tries to isolate the suspected zone immediately and performs the second trial switching action to ensure the suspected area is correct. If the suspected RCD zone is proven to be incorrect, the trial switching sequence is applied starting with dense roll sequence. After the faulted RCD zone has been isolated, FLIR proceeds into a restoration sequence to restore the unsupplied RCD zones with backup connections or from the upstream substation. [39]

FLIR functionality is configurable to each feeder separately from the settings dialog of the SYS600. Depending on the feeder type, settings can be configured to include the first trial switching, trial switching sequence, the second trial and if feeder can be used as a backup connection. Kajave representative stated that the operator normally does not use the first trial, when the fault can be expected to be close to the substation by alarming undervoltage detection and high magnitude fault current measurements. In that way, unnecessary voltage dip on adjacent feeders and strain to network components can be avoided. The FLIR and auto-reclosings are not used in entirely cabled feeders, since short-circuit currents are high and the fault reason is usually human-related. Thereby, additional switching actions could cause danger to the network equipment and potential life threat. [62]

Comprehensive situation awareness was emphasized to be the key factor for efficient fault management especially in the major disturbance situation. Even though FLIR can perform the fault isolation process simultaneously for multiple faults, the overall situation awareness of the operators is often decreased. Therefore, the FLIR is currently disabled during the major disturbance. Trimble FLIR has so called storm mode, in which automation isolates only the weatherproof part of the network and leaves rest of the fault handled by the operator. This operating mode has not yet been tested by the Kajave, because no severe weather conditions have been occurred after implementation. [62]

Due to varying conditions of the major disturbance situation and the current state of automation, it was speculated that automatizing the whole process will be challenging task or even not possible at least in the next decade. It was noted several times during interview, that reliable and straightforward operation of the FLIR is more important than taking all special situations into account. According to the Kajave representative, there are feeders that does not support the FLIR operation due to old relay technology, but this is considered in daily operation. [62]

6.3 Koilis-Satakunnan Sähkö Oy

Koilis-Satakunnan Sähkö Oy (KSAT) is a DSO operating in the area including parts of Pirkanmaa, South Ostrobothnia and Central Finland regions. Network control center of KSAT is located in the city of Virrat. KSAT distributes and sells electricity for about 16 000 customers according to the 2018 statistics. The total length of the distribution network is approximately 4 000 km, of which about 1 600 km is MV network. According to the statistics of 2018, cabling rate of the MV network is 10,0 % and 36,4 % in the LV network. There are approximately 160 remote-controlled disconnectors installed in the distribution network, which is about 10 RCDs per 100 km of MV network. [57] KSAT is using the whole ABB MicroSCADA Pro product portfolio including DMS600 NE, DMS600 WS and SYS600.

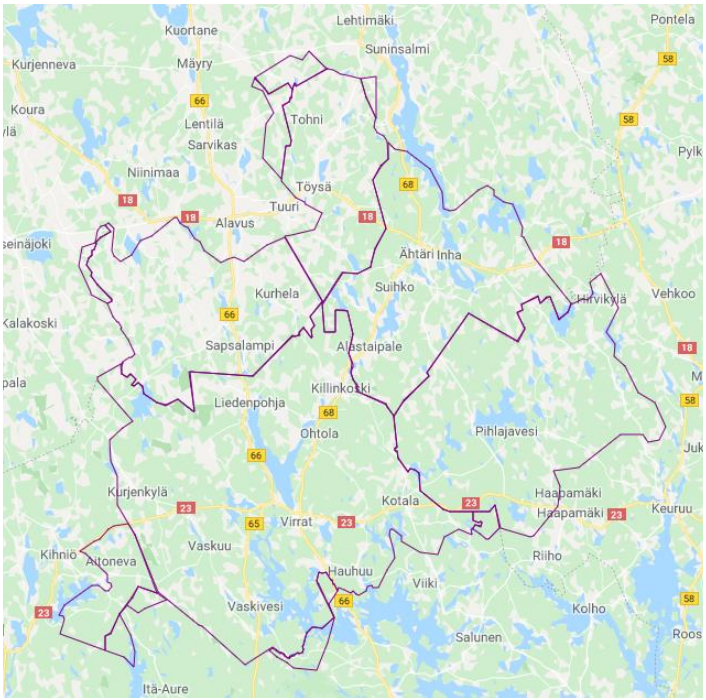

__Figure 35.__ Distribution area of the KSAT according to the outage info map presentation [63]

To enhance the distribution reliability, cabling rate and amount of automation is increased along with reserve connections for rural feeders. Especially remote reclosers are proven to be remarkably beneficial in the boundary of cabled and overhead line feeder. A pilot project for cabled network fault indicators is also on the go, but there is no user experience yet. Representatives stated that there are not reliable and cost-efficient fault indicator solution for large scale deployment in the market. In addition to the cabling and automation, distribution reliability is improved by relocating overhead lines to roadsides and maintaining the existing network equipment carefully. According to interviewees, whole distribution network will not be cabled due to long distances. There was also a mention, that cabled network could still be prone to faults in the agricultural areas having lots of excavation. [64]

The primary information of fault location process performed by the operator is calculated fault distance. However, fault current measurements are not usually available, and the operator must use the best knowledge about the network. The calculational fault location has been working rather well in short circuit faults, but it cannot be used in the case of an earth fault. However, earth fault protection trip time is in most cases delayed and faults develop into short-circuit faults, which can be located more easily. When there are no initial data to be used, operator must use intuition and knowledge about the network. Some of the operators have the experience about the most fault prone areas, and certain line sections can be prioritized in advance. There is still no efficient way to store the information about the environmental hazards, but functionality for that could be beneficial according to the representatives. When there are no initial data for the fault location, the operator uses commonly the bi-section method at first and after that performs the zone-by-zone rolling. Supply is also restored during fault isolation process, if certain branches can be proven healthy. [64]

The operator must use careful consideration of using trial switching during dry season, when the chance of wildfire is high. According to the interviewees, wildfires due to overhead line faults occur approximately couple of times during summer. Also, the covered overhead line was noted to be limiting factor when utilizing trial switching, since conductor can be damaged rather easily by high short-circuit currents. Repair work of the covered overhead line is highly time consuming, and therefore automation should take possible conductor strain into account. Trial switching must not be utilized in the cabled feeders due to potential damage to the underground cable by high short-circuit currents. It was also noted that underground cable faults are usually caused by human error, so additional switching actions could be deadly dangerous. FLIR functionality was proposed to be configurable for each feeder separately. [64]

SCADA pictures of KSAT include documentation for the backup connection ability to restore the adjacent feeder. All in all, loads on the rural feeders are rather small and backup connections can re-supply wide portion of the network. If in doubt, operator also checks the constraint violations according to the DMS calculations. It was noted that long rural feeders should not be restored by urban feeder especially during severe weather conditions. As the urban feeders are mostly cabled, FLIR functionality would not be even used, and thus restrictions for supply restoration may not be needed for feeder level individually. [64]

For the remote-controlled switching device communication, KSAT utilizes own radio network. Communication delays were approximated to be from seconds to 30 seconds depending on the location of the RCD. Varying terrain and long distances set challenges for the communication and controllability of single pole-mounted RCDs in the rural areas. It was noted that all switch operations are not transmitted by the first try, but operator sometimes needs to perform switching action multiple times before RCD operates. Trial switching sequence of the FLIR is desired to try controlling the switch multiple times, before interrupting the sequence. If the position indication is not received after multiple attempts or switch is indicated to be in abnormal position, sequence should be aborted to avoid possible electrical safety risks. [64]

The network control center of KSAT is not manned full time, so the FLIR is supposed to be most beneficial at night, when operation is carried remotely from home. According to the interviewees, the FLIR sequence could locate and isolate the fault simultaneously as the operator prepares the laptop setup and takes the remote connections to the DMS and SCADA. Also, if the operator is not directly besides the remote setup, the response time can even increase without automation participating in the process. It is crucial that FLIR gives the operator a clear guidance of the operations performed. Also, possible malfunctions, such as communication or software errors should be informed to the operator. Thereby, the operator is instantly ready to take over the responsibility of the fault clearing process and the situation awareness is maintained. [64]

Like in other interviewed DSOs, the situation awareness was emphasized to be crucial in major disturbance situation. As the switching state can vary significantly from the normal state, automation is supposed to disturb the actions carried out by the operator. Automatic switching actions could also cause electrical safety risk, when high number of field crews are dispatched around the network in challenging conditions. In major disturbance situation, FLIR can operate as an assisting tool for the operator while determining the possible fault locations. It was also noted that after automation has been confirmed to reliably operate in normal conditions, also disturbance situations could be partially handled using autonomous operation of FLIR. [64]

Representatives of KSAT emphasized that user interface of the FLIR functionality must be uncluttered and simple to use. Operators are using varying setups from large wide screens of a control center to a small laptop when the operator is on duty at home. Interviewees noted that rather straightforward logic of the FLIR is preferred than all-encompassing solution to every special situation. While variety sources of open data are available to be used in fault inference, processing and storing the massive amounts of data is assumed to weaken the overall performance of the system. [64]

6.4 Summary of the interviews

During the interview process, several functional requirements and development needs were gathered. All the interviewees noted that the overall situation awareness of the network should be maintained even though automation participates in the fault management process. Currently major disturbance situations are preferred to handle by the operating personnel of the network control center due to varying and unusual conditions. According to the interviewed DSOs, FLIR is the most beneficial during nighttime when network operation is carried out by remote operators at home. To achieve fluent operation between automation and the operator, FLIR should inform the user of the performed actions and point out possible malfunctions or errors.

According to the interviews, distribution system operators are utilizing various resources to meet the distribution reliability requirements by the year 2028. While the network renovation by underground cables and increasing the level of automation tends to be the key method, it is not economically feasible for all rural feeders. DSOs are additionally maintaining overhead line routes as wood-proof and moving overhead lines besides road shoulders. The current fault indicator technology was stated not to be reliable or cost-efficient enough for large scale deployment, but pilot projects are carried out mainly in underground cable network to find the suitable solution. Distributed energy resources enhancing the distribution reliability were not considered yet among the interviewed DSOs, since distribution system operators are not allowed to own DER units.

General opinion of the DSOs was that automation can perform trial switching independently, because it is the common and usually the only way to isolate the fault also by the human operator. Normally operator determines a remote-controlled disconnector that coarsely isolates the fault either feeder upstream or downstream. After the coarse isolation, zone-by-zone rolling method is applied. In case of a short feeder, trial switching process can be also carried out by performing straight zone-by-zone rolling from the substation. Determining the coarse isolation disconnector is based on operator's knowledge of the prevailing conditions and experience about the most fault prone areas. If available, fault distance calculations are used to narrow down the suspected area. Therefore, the optimal coarse isolation switch is challenging task to determine by automation without any initial data available. Occasionally, the operator closes the circuit breaker after the auto-reclosing sequence to ensure the fault is still active. However, this is highly dependent on the prevailing situation due to possible equipment failures, so according to the interviews verifying trial switching should be optional in the feeder level settings.

Manner of supply restoration also varies by the operator. While some of the operators first locate and isolate the faulty remote-controlled zone, others restore the supply during isolation process. The common way according to the DSO interviews, tend to be supply restoration during isolation process if certain feeder branch can be stated as un-faulted and re-energized from the adjacent feeder. By these means, restored branch must be isolated from the main supply route to avoid additional short break caused by trial switching process. Operator uses careful consideration, when supply will be restored via backup connection. Backup connection may be ranked out by important industrial customer or high number of customers, even if technical constraints are not violated. By these means, feeder level setting should include option to disallow use as a backup supply. During severe weather conditions more than one fault can occur in the feeder and especially urban feeders shall not be used in the supply restoration for fault prone rural feeders. FLIR functionality should include mode, which requires confirmation by the operator before restoration sequence is applied.

To ensure the electrical safety among the network, FLIR should be easily configurable to each feeder separately. Trial switching should be easily disabled from a certain feeder with maintenance work e.g. during a tree clearance besides the overhead line. In these situations, also auto-reclosing sequence is disabled. Interviewees proposed that automatic trial switching should be automatically disabled, when the auto-reclosing is switched off. However, maintenance outage, where working crew is not in contact with live network, should not normally prevent the use of trial switching in the feeder. When the maintenance outage is carried out according to the electrical safety rules, switches are locked out to prevent unwanted re-energization and work earthing is set up. FLIR cannot operate these locked switches and thus no hazardous situations were considered.

Communication to remote-controlled switching devices was stated rather reliable especially in disconnector stations having multiple RCDs installed. Single pole-mounted disconnectors along the rural feeders need sometimes couple of control actions to operate due to long distances and varying terrain. Disconnectors are inspected regularly to avoid malfunctions and equipment failures. Communication delays are said to be approximately from couple of seconds to 30 seconds before status indication is received. DSO representatives noted that automation should try to operate switching device couple of times before aborting the sequence. If position indication of the switching device is not received after control attempts, or switch is indicated to be in abnormal or faulty position, switching sequence should be aborted and handed over to operator to avoid risk in electrical safety.

Because of the varying conditions and different levels of network automation, all-encompassing solution of the FLIR is too complex to operate reliably in daily use. According to the all interviewees, the functional implementation should rather straightforward at least in the first production version. After the first implementation is proven to operate reliably in daily use, more sophisticated inference methods utilizing e.g. open data and fault history could be added.

7. IMPROVEMENTS TO FLIR FUNCTIONALITY

According to the DSO interviews, the key improvements to the FLIR functionality are a trial switching sequence, simple and easy to use interface, and different level of configuration of the FLIR. The FLIR should also be able to handle multiple faults simultaneously in separate geographical areas. Especially at the first stage, FLIR is desired to be as simple as possible to reduce the system side errors. DSO representatives noted that a reliable and a rather simple operation is more important than full coverage of all special situations. By these means, the basic functionality of the FLIR sequence can be proven to operate reliably and efficiently with current penetration of network automation.

In the future development of the fault management, more sophisticated methods and data sources may be used. An increasing amount of distributed energy resources with two-way communication infrastructure could be used to coordinate micro grids automatically during the supply restoration sequence. Improved protection and fault indicators may also enable better fault location functionalities to avoid unnecessary trial switching. Widely available open data, such as weather forecasts, forest height data, and road vector data, could also improve fault inference in the future [65]. External tool for open data processing should be developed, because processing large amounts of data would most probably lead to performance issues in DMS600 and thus disturb the real-time operation of the network.

Also, some minor improvements that were noted during the DSO interviews are introduced. All the interviewed DSOs mentioned that a tool for maintaining and visualizing potentially fault prone line sections could be used to assist FLIR functionality and the operator in locating the fault. This feature was chosen for a closer inspection because existing functionalities of the DMS600 could be rather easily utilized in the development of the feature. Altogether, better visualization of the network status should be readily available to enhance the overall situation awareness during disturbance situations.

This chapter provides and analyses different kind of functionalities and solutions required by the customer. Motivation of the functional description is to provide useful information to MicroSCADA Pro research and development team for the implementation of the feature. Methods for determining automatic switching actions during trial switching sequence are presented based on information gathered from DSO interviews and literature review. List of functional specifications is presented in the Appendix C.

7.1 Evaluation of the trial switching method

To avoid unnecessary strain to the network components and speed up the trial switching sequence, switching actions must be optimized correctly. Additionally, harmful short in-breaks to customers during the isolation process must be minimized. [50] When the NCC operator is utilizing the trial switching procedure, decision of the switching sequence is usually based on intuition or operators' knowledge about surrounding conditions [58, 62, 64]. Modeling of this kind of knowledge-based information is a troublesome task, and it would require e.g. advanced neural network applications and massive amounts of data [44]. Since FLIR functionality is desired to operate even without initial data of the fault, decision making process must be based on the data associated to the distribution network model, such as:

- Conductor length and cabling ratio
- Number of customers and connected power
- Availability of backup connections

The bi-section method requires feeder to be divided into approximately two equally sized parts in terms of disconnector zone length or probability of the faults. Bi-section method is usually preferred method in manual isolation process due to slow moving time of the field crews. Decision making based on the physical lengths of the remote-controlled zones are usually not viable due to e.g. underground cable being less prone to faults compared to overhead line and modern communication allowing switching actions within seconds. [12] Topology of the feeder is also varying as the densely populated areas tend to have multiple remote-controlled branching points with open backup connections, but rural parts of the feeder are more straightforward with less network automation installed. Therefore, the term bi-section method is sometimes obsolete and rather coarse trial switching method can be used. To minimize the circuit breaker trips, disconnector should be chosen in a way that fault can be most likely stated to locate in the downstream direction of the chosen RCD.

There are three possible outcomes after the feeder is coarsely isolated. If the substation circuit breaker trips, fault is located in the upstream direction from the isolating RCD. Whereas, the circuit breaker stays closed fault can be either located in the downstream direction from the isolating RCD or the fault has cleared by itself. Fault may be cleared by itself e.g. when tree branch has ignited and fallen off from the overhead line after the short-circuit [4]. Depending on the prevailing conditions, operator occasionally performs additional trial for the entire feeder to ensure the fault is still active. Deploying the first trial may cause unnecessary trip and additional stress to network components especially in the mixed feeders, containing both overhead line, underground cable and covered overhead line. The first trial would enhance the overall performance of FLIR, but according to interviews, it should be optionally enabled for feeders.

Efficiency of the coarse trial is significantly improved, if at least estimation of the fault area can be deduced. Thereby, coarse isolation can be performed in a way that the first isolation does not cause the circuit breaker to trip, and certain branches can be restored and isolated from the main supply route via adjacent feeders. Figure 36 presents an example situation, where fault distances can be calculated on two separate branches. Both suspected branches can be isolated from the upstream direction by using remote-controlled switches at station Z9 marked with red borders in the figure. Step by step example of the isolation and restoration sequence is described in the Appendix D. RCD stations are often equipped with more reliable communication compared to individual pole-mounted RCDs along the line, and coarse isolation sequence is preferred to execute by these means [39].

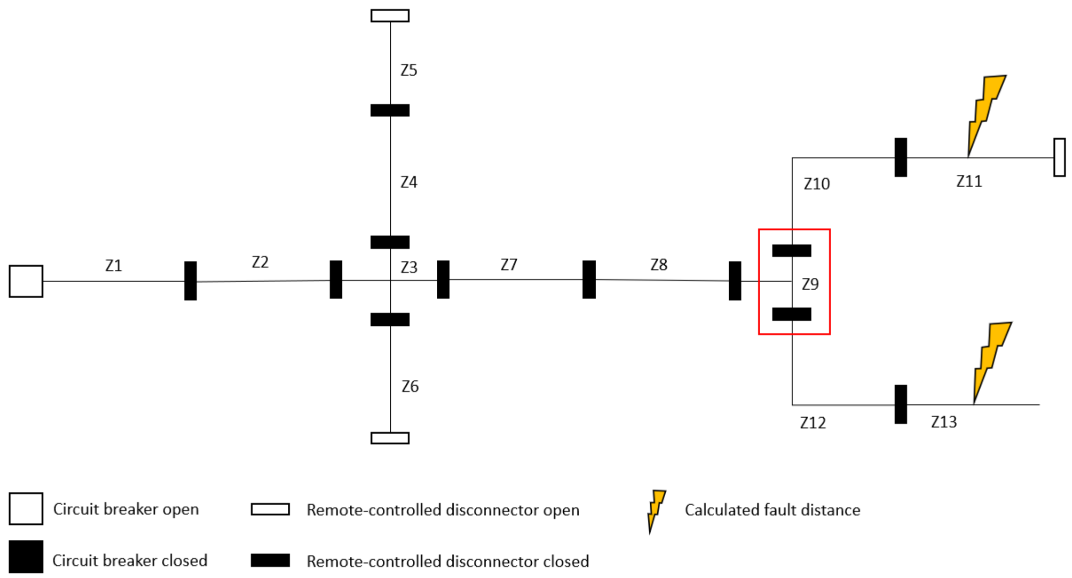

Figure 36. *Example of determining the coarse isolation switches according to calculated fault distances*

Coarse estimation utilizes the calculated fault distances as the primary source of determining the opened RCDs. If fault distance calculations are not available, the DMS600 WS fault inference can be used to calculate the RCD zones, which are most likely not faulty. As described in the chapter 5.2.1, the fault inference utilizes fault indicator operations, conductor types and overloading of components to deduce likelihoods to each manual and remote disconnector zone. Figure 37 presents the determination of coarse isolation switch based on likelihood calculation.

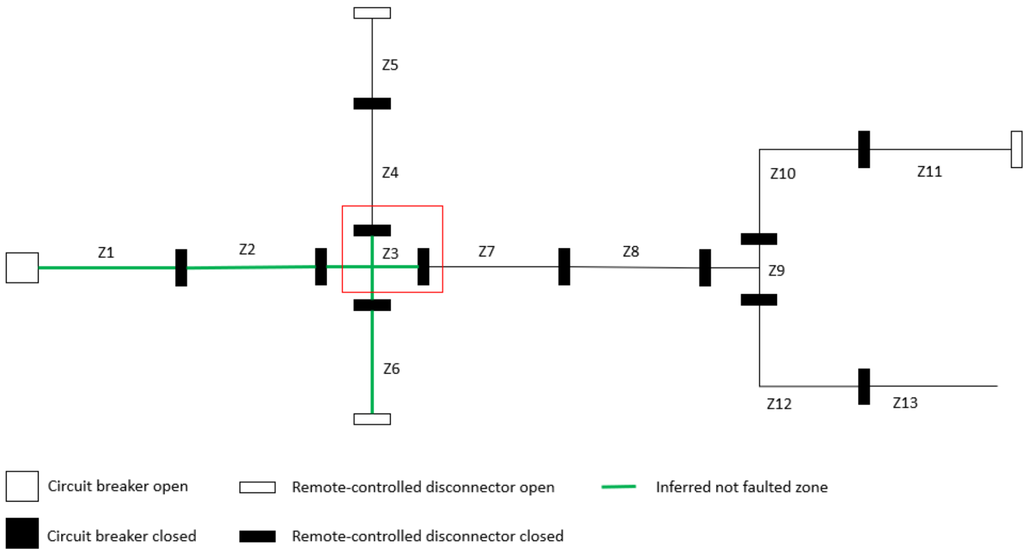

Figure 37. Example of determining the coarse isolation switches according to fault inference likelihoods

Likelihood of the fault occurring in the overhead line is highest during severe weather conditions and after heavy snowfall. Therefore, variable of cabling ratio should be weighted according to the prevailing situation. Although weather data sets, such as wind speed and direction, temperature and cumulative snowfall, provided by the Finnish Meteorological Institute [66] are available, acquisition and processing high amounts of data could turn out as a bottleneck for performance and system disc usage. Currently fault inference parameters must be set by the user as presented in the chapter 5.2.1.

If coarse isolation switches cannot be determined, coarse isolation sequence moves to zone-by-zone rolling method beginning from the substation. By these means, more straightforward logic can be obtained, and additional trips can be minimized. Flowchart of the proposed coarse isolation sequence is presented in the Figure 38.

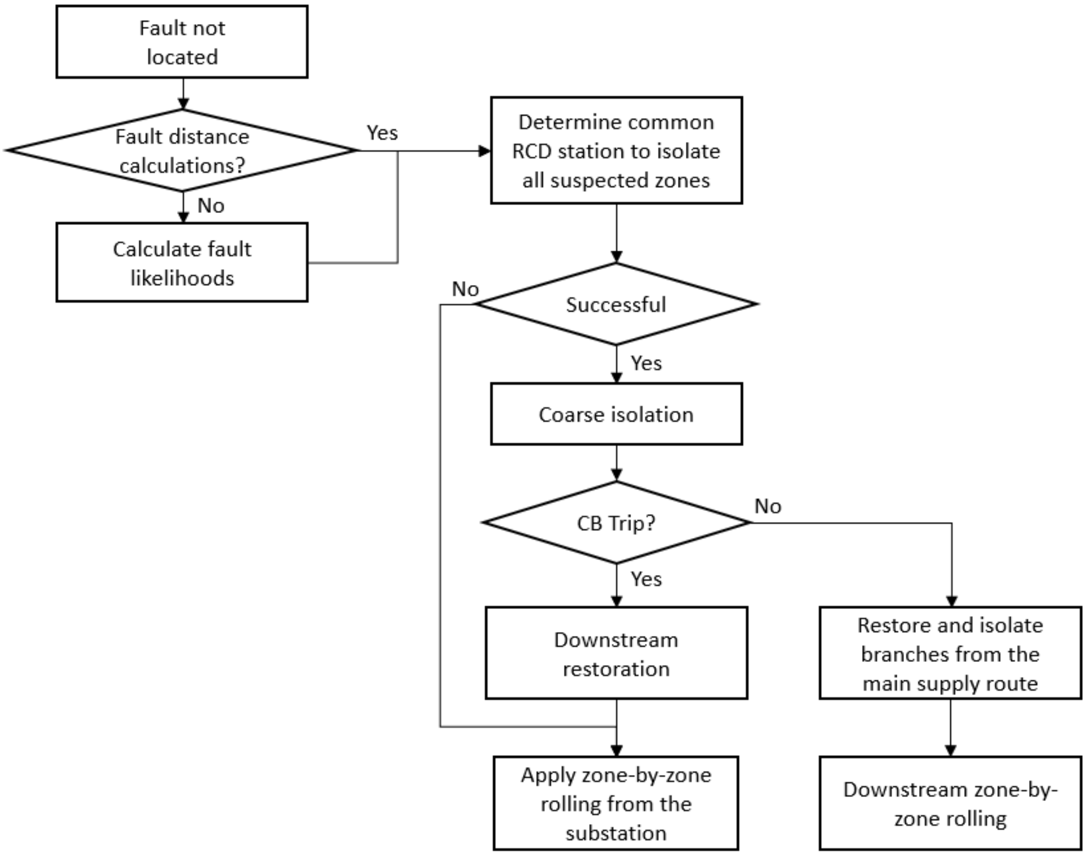

Figure 38. *Flowchart of the coarse isolation logic with suspected fault area determined*

After the coarse isolation switches have been determined and opened, the upstream is re-energized. If the circuit breaker trips, fault can be stated to be between substation and the isolating switches, and thereby downstream of the feeder can be restored via available backup connections. Zone-by-zone rolling method is applied to the upstream part to minimize additional trips. Whereas the circuit breaker stays closed, fault is located behind the coarse isolation switches and trial switching sequence is continued with zone-by-zone rolling starting from the RCD station. To minimize the customers affected to additional short break in the re-energized upstream, RCD branches with backup connection are supplied from adjacent feeders and isolated from the main supply route.

In the upstream branch restoration, temporary loop connection is formed until the branch can be isolated from the main supply route. If backup connection is supplied from the other substation, capability of parallel operation of primary transformers must be checked. The parallel operation of primary transformer requires that phasor groups, short-circuit impedances and voltage ratios are equal and rated powers do not exceed ratio of 3:1. [67]

Zone-by-zone rolling is applied after the coarse isolation sequence. As described in the chapter 4.1.3, remote-controlled zones are re-energized one by one until the circuit breaker trips. Utilizing zone-by-zone rolling method manually with help of the field crews is usually time-consuming task, but with automation single switching action can be conducted within seconds. Zone-by-zone rolling method also reduces the possible number of circuit breaker trips to one, if only single fault occurs in the feeder. Like mentioned earlier, distribution network feeders are usually branched, and individual branch can contain several RCD zones. To minimize total outage costs and number of short breaks for customers, switching actions should be optimized in a way that as much customers as possible can be restored via backup connections during zone-by-zone rolling method.

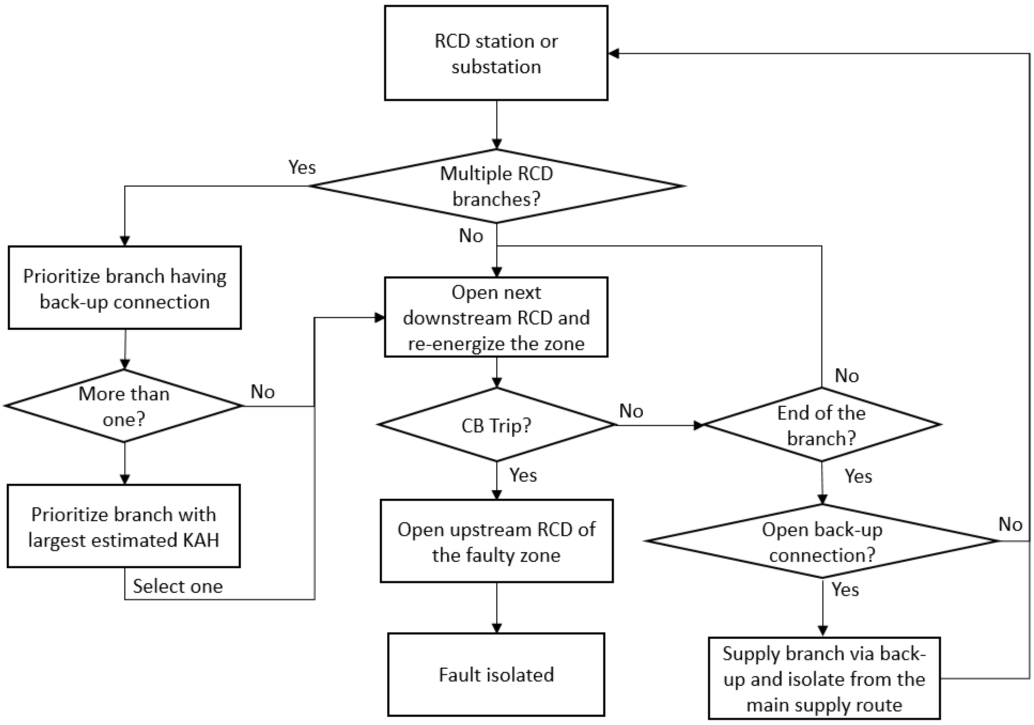

Figure 39. *Flowchart of the zone-by-zone rolling method*

In the proposed zone-by-zone rolling method, branches in RCD station are prioritized according to available backup connection and estimated customer outage costs. When the zone-by-zone rolling sequence has multiple branches to try, one with the largest estimated outage costs with backup connection is trajected first. If whole branch is examined and supply can be restored via open backup connection, supply shall be restored, and branch isolated from the main supply route.

After the fault has been isolated to a single remote-controlled disconnector zone, RCD zones can be restored from the feeding substation or via backup connections, if available. Constraint violations are calculated by the DMS and if limits are exceeded, backup connection is not used. If there are multiple backup connections available, DMS determines the most capable in terms of load flow and protection analysis.

7.2 DMS600 WS FLIR functionality

Current fault isolation and restoration mode of the DMS600 WS is based on determining one faulty RCD zone in the faulted feeder. That requires either accurate fault current measurement acquired from the relay or reliable fault indicator operations. According to the interviews, initial data is rarely available, or it is not precise enough to locate the fault. Therefore, the trial switching sequence must be introduced alongside the fault inference of the current fault management. Existing fault inference and fault distance calculation of the DMS600 can be used to prevent the unwanted trial switching or help to narrow down the suspected fault area. In case of a long feeder with multiple branches, fault inference could point out definitely un-faulted zones to be restored. Thereby, number of long outages can be reduced as the interruption time of the restored customers stays under 3-minute limit.

The FLIR should be able to handle multiple simultaneous faults. Interviews noted that already widespread distribution areas are becoming even larger as the network operation of several DSOs tend to be centralized into shared network control centers. Therefore, several FLIR instances should be able to simultaneously operate in separate fault handling areas. With individual FLIR areas, there would not be chance of multiple FLIR sequences trying to operate the common switching device and potentially interrupt the isolation and restoration sequences. Area model would also allow a better controllability as certain areas could be assigned to automation and others to the NCC operator to handle. Options for FLIR area definition tools are:

- DMS600 area component, which allows the operator to outline boundaries on the geographical network view
- Dynamic regions defined for primary transformer
- Network fed by certain primary substation or user defined list of substations dynamically according to the switching state

The area component model requires the administrative user to define the geographical boundaries around the remote-controlled switching devices used in the FLIR instance of a certain fault handling area. Therefore, FLIR areas should be manually updated when the normal switching state of the network changes. This model would be suitable for rather small distribution areas but updating the area components could be too complex in larger distribution networks.

Region model is designed for dividing the network operations to individual operators with different level of user permissions. The region is defined as an attribute of a primary transformer and it is dynamically updated to the network components according to the network topology. Region model allows the management of control rights according to the user groups of the DMS600, but it could also be used to assign individual FLIR instances to a certain region. [52] To prevent possible user errors, only one FLIR instance should be possible to attach to one region.

One possible solution for creating the area model is to use a user defined group of primary substations. Likewise, in the region model, the boundaries of the FLIR area are formed dynamically according to the switching state of the distribution network. In this model, the user creates a FLIR operating area and defines which substations are included. Attaching a substation into multiple area models should be not allowed to prevent overlapping actions. Proposed control hierarchy of the FLIR area model is presented in the Figure 40.

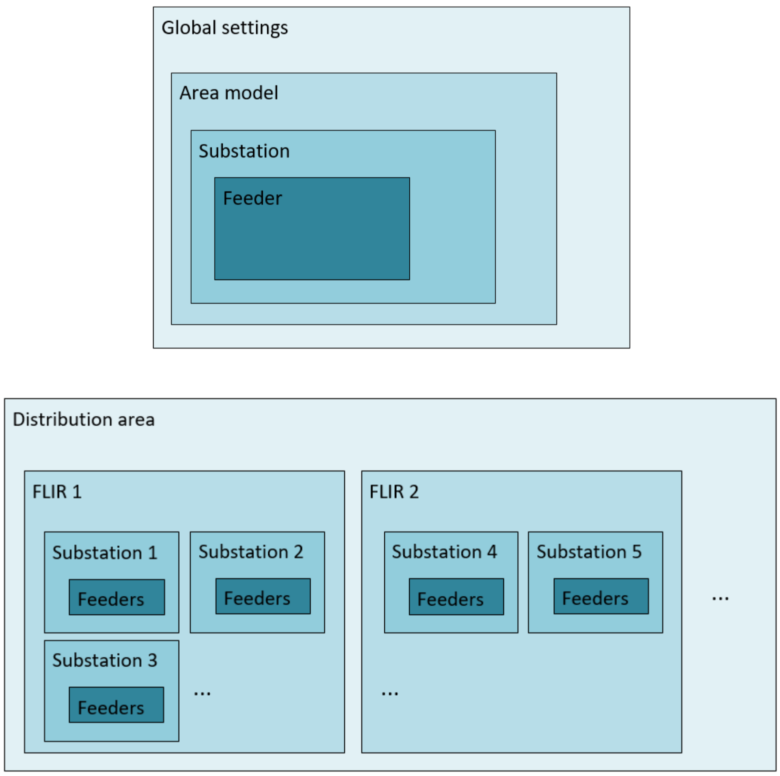

Figure 40. *Settings hierarchy of the FLIR area model with an example configuration*

Interviews noted that each of the feeder should be individually configurable to be used in the FLIR sequence. For example, trial switching sequence should not be used in the cabled feeders and usage of the trials with mixed feeders varies among the DSOs. Certain feeder can also contain important customers, such as large-scale industry, and thus cannot be used as a backup feeder. [58, 62, 64] According to the interviews, feeder level settings should include at least:

- Is FLIR enabled?
- Is trial switching sequence enabled?
- Can feeder be used as a backup connection?
- Additional trial switching to confirm faulty zone after isolation

Feeder level settings are disabled by default and must be configured by the user when new feeder is added to the system. Thus, configuration errors of the system can be reduced and unwanted operation of the FLIR to be avoided. E.g. FLIR with trial switching sequence enabled, can cause damage to the network equipment in the underground cable feeders.

General settings include option for the overall FLIR functionality to be switched on or operated in a disturbance mode. According to the DSO interviews, additional disturbance mode should restrict certain features of automatic fault isolation and restoration mode. Disturbance mode should try to isolate the fault and restore the supply from the feeding primary substation but controlling of the reserve connections should be prevented not to disturb actions of the operator or cause outages to adjacent feeders. Settings are inherited from general settings towards feeder level settings, to maintain better controllability of the system.

There should also be an option to allow trial switching according to time of the day. The trial switching sequence could be allowed to operate only at nighttime when field crews are not operating among the distribution network. By these means, the network control center can maintain electrical safety more easily. Additionally, the FLIR would not disturb the operator if the trial switching sequence is disabled during office hours.

Before the trial switching sequence is executed, DMS600 WS determines remote controlled switching devices of the faulty feeder to be reserved for the FLIR sequence. DMS600 WS then sends the list of switches for SYS600 to check controllability. If switches are interlocked, communication cannot be confirmed or the status indication is not up to date, FLIR leaves the switch out of the sequence. While the FLIR sequence is running, control of the switches must be restricted from the user. By these means, the human operator cannot accidentally perform switching actions to interrupt the sequence.

To avoid misunderstanding, control dialog should have a clear indication about reservation to the FLIR sequence. To obtain more explicit visualization of the trial switching sequence, the reserved switches can be highlighted in the network view of the Workstation and in the single line diagram of the SCADA picture. Example of the reserved switching device visualization is presented in the Figure 41.

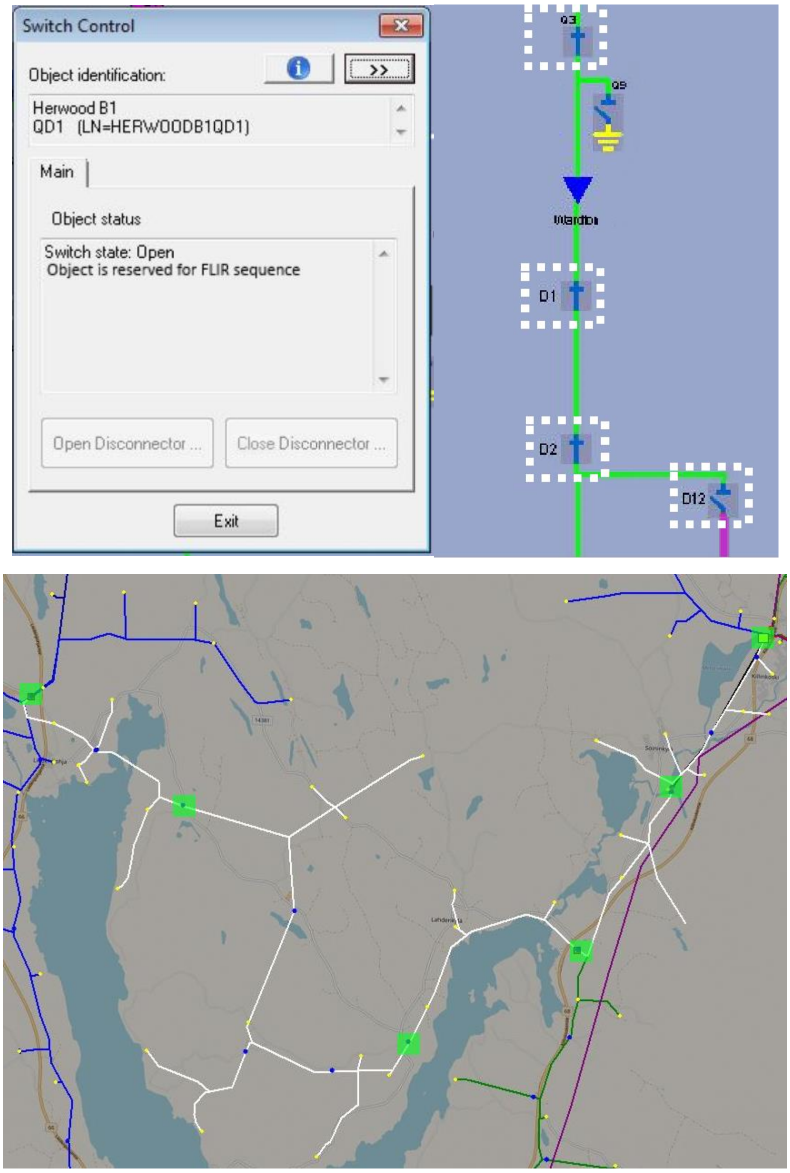

Figure 41. *Example of visualizing the RCDs reserved for the FLIR sequence*

According to the all interviewed DSOs and attendees of the workshop, usability of the FLIR control and settings dialog is highly important. User interface must include a clear indication whether FLIR is running or not and which actions have been executed. Also, errors during sequence must be clearly visible with an explanation of the malfunction.

Operation dialog of the FLIR should also include an easy to operate kill switch, if automation needs to be stopped by the operator. Example of the FLIR dialog is presented in the Figure 42.

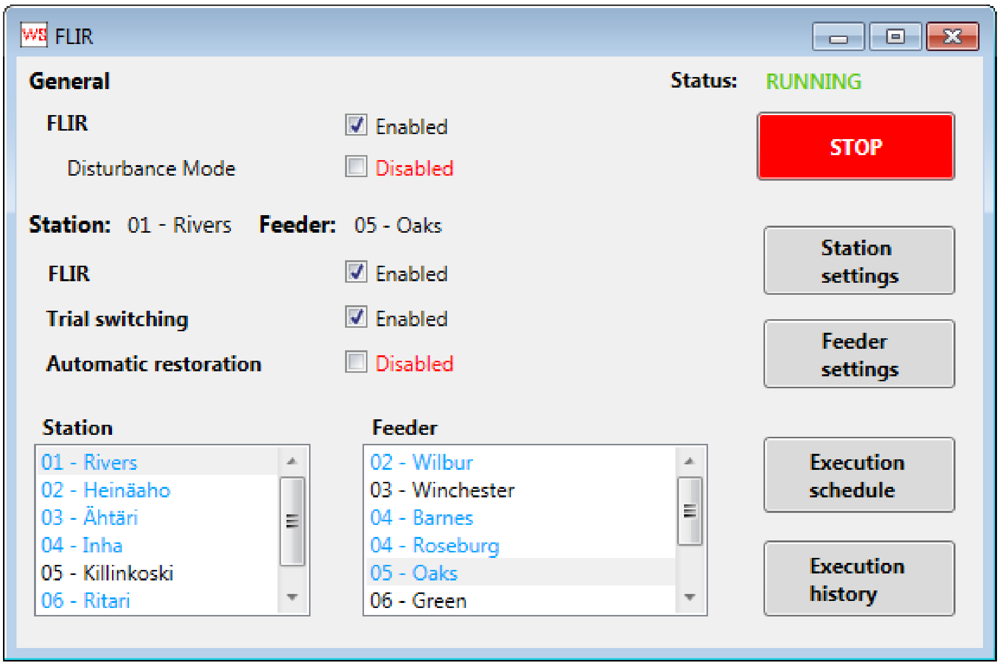

Figure 42. *Example design of the FLIR settings dialog*

Settings dialog should clearly indicate substations and feeders that are included in the FLIR functionality. If proposed area model is used, substations included in the certain area must be also indicated e.g. with different color or area drop down menu. To achieve better usability, feeder level settings should be configurable without stopping the overall FLIR functionality. Therefore, FLIR settings should be stored e.g. into the SQL database rather than flat configuration file.

7.2.1 Fault inference

After the DMS has created a new fault case, all the available data, such as fault current measurement and fault indicator operations, are used to inference the possible faulted RCD zones. If the fault can be determined to be in a single remote disconnector zone, fault can be directly isolated without network straining trial switching. When the fault has been isolated, substation circuit breaker is closed. If CB stays closed, fault has been successfully isolated, and the trial switching sequence can be avoided. Whereas the circuit breaker trips, fault inference can be stated incorrect and FLIR starts to execute the trial switching sequence.

Prevailing conditions affect the fault inference by weighting e.g. fault likelihood in overhead line compared to underground cable. Current fault inference logic requires weight parameters to be manually set by the operator. According to the interviews, the operator rarely has time or attention to adjust the parameters due to high workload especially in the disturbance situation. To obtain more straightforward approach, disturbance mode of the FLIR could determine the weatherproof cabled portion of the feeder to be restored from the upstream direction.

Several manually controlled disconnector zones may exist in isolated RCD zone, especially in a long rural feeder. The isolation process is continued by the operator dispatching field crews to conduct switchings of manually controlled disconnectors that can be time consuming due to long distances and challenging terrain. More precise fault inference using only the isolated RCD zone as an entity, and manual disconnector zone are evaluated against one remote-zone.

7.2.2 Isolation and restoration sequence using trial switching

If there are no initial data available or fault inference function cannot determine faulty zone, trial switching sequence is applied. The first step of the trial switching sequence is to determine the coarse isolation. After the faulted feeder has been coarsely divided, more precise isolation methods is applied by means of zone-by-zone rolling. In case of a lengthy feeder, after the coarse method the suspected fault zone may contain multiple RCD zones and branches, so the execution time of the sequence may affect to the overall feasibility. Execution time of the zone-by-zone rolling can be reduced, if remote-controlled zones can be further merged, e.g. by first experimenting remote-controlled disconnector stations at branching points. Proposed FLIR sequence is presented in the Figure 43.

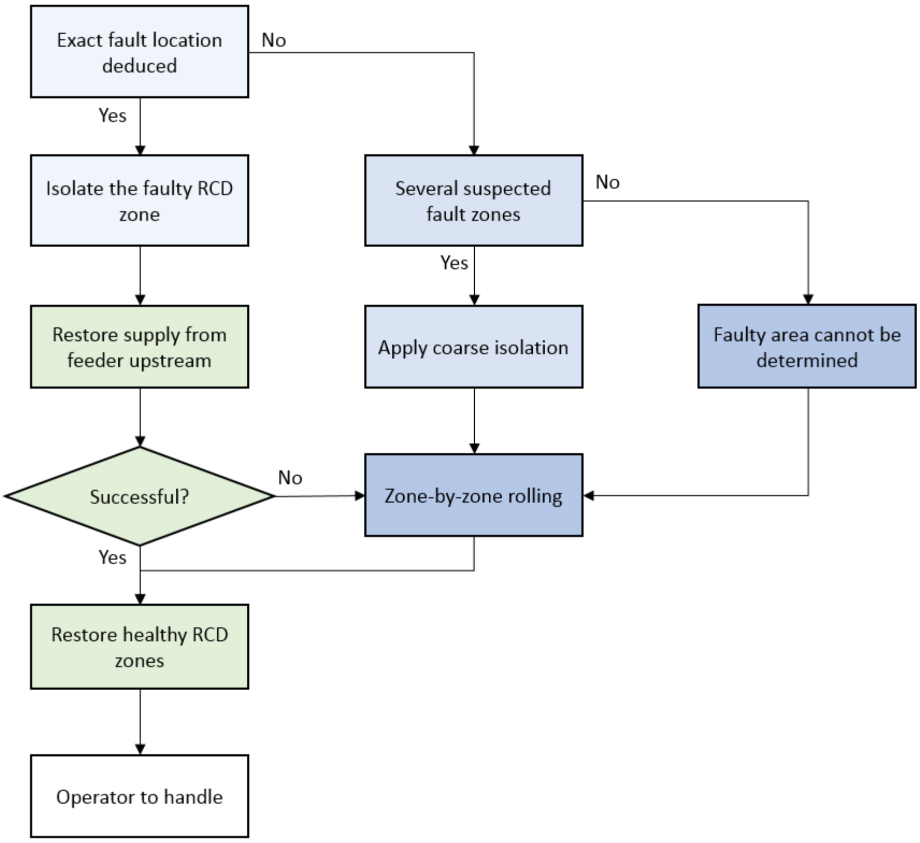

Figure 43. *Proposed trial switching sequence*

As the overall FLIR functionality is desired to be straightforward according to interviewed DSO representatives, proposed logic utilizes three different initial conditions:

1. Exact fault location determined by fault distance calculation.
2. Several suspected faulty zones by fault distance calculations or fault inference.
3. Faulty area cannot be determined.

When a single RCD zone can be stated as faulty, a switching sequence is created to isolate the zone. After the isolation, supply is restored to the feeder upstream and if circuit breaker stays closed, fault isolation can be stated correct. Additional trial switching can be performed against the isolated RCD zone, to confirm the suspected fault. If the fault can be successfully isolated to the single RCD zone, supply is restored also to feeder downstream via backup connections. Whereas the circuit breaker trips, fault isolation can be stated as failed and FLIR sequence continues with zone-by-zone rolling starting from the substation.

If several suspected faulty zones are available, FLIR should try to determine RCDs to coarsely isolate all suspected faulty zones as described in the chapter 7.1. After the coarse isolation, zone-by-zone rolling is applied either from coarse isolation RCDs or from the substation depending on the circuit breaker trip. Zone-by-zone rolling should prioritize branches including backup connections and largest estimated customer outage costs, so as much as customers can be resupplied during isolation sequence. If faulty area and coarse isolation switch cannot be determined, zone-by-zone rolling is applied from the substation to avoid unnecessary trips.

The whole trial switching sequence cannot be determined beforehand, because the next step depends on tripping of the circuit breaker. Therefore, sequence should be created dynamically during runtime or determine all possible situations considering whether the circuit breaker trips after certain RCD switching action. Figure 44 presents an example path of zone-by-zone rolling, where the execution depends on the trip of the circuit breaker.

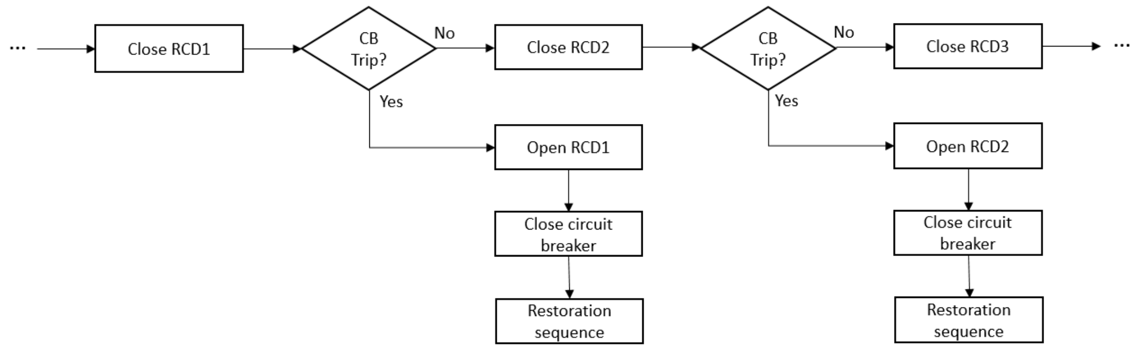

Figure 44. *Structure of trial switching sequence*

In the switching model, every disconnector switching action branches to two different options decided by the circuit breaker trip. If entire sequence can be executed without the circuit breaker trip, fault can be stated as cleared by itself and supply can be restored from the feeder upstream.

After the fault has been isolated and supply has been restored to the feeder upstream and to the healthy RCD zones via backup connections, fault is left for operator to handle. Manual isolation sequence is created to assist operator, if fault inference can point out possible faulty manual zones. Also, a switching sequence to restore the switching state to pre-fault situation or to the normal switching state is created for the operator to execute.

7.3 Additional improvements and future consideration

Besides the FLIR functionality, some features supporting the fault management were pointed out during DSO interviews. When the operator is performing fault isolation process, time and available workspace is usually limited and thus analyzing the prevailing conditions may not be possible. According to the interviews, tool for documenting and maintaining data of fault prone areas would improve the fault inference and fault management of the network control center operator. Example of the functionality is presented in the chapter 7.3.1.

Also, better utilization of available open data could be used to support the fault inference of the DMS600. Open data including e.g. weather forecasts and terrain conditions allows Ministry of Finance conducted The Finnish Open Data Program during years 2013 – 2015 to accelerate availability of the data sources by public sector. Target of the program was open data sources to machine-readable format and harmonize the terms of use by the means of JHS 189 'License for use of open data'. [68] Machine readable open data could be automatically processed with external tool and saved to network database to support fault inference of DMS600, or to be visualized for operator.

Although, distributed energy resources are not yet in wide consideration of distribution system operators, amount of DER units are constantly increasing, and second generation of AMR infrastructure should provide better controllability [69]. Smart Grid Working Group mandated by the Ministry of Economic Affairs and Employment stated in its final report that DSO should not own or use electricity storages by themselves, but if there are no suitable market driven service available, distribution system operator could own and use electricity storages for example improving the distribution reliability. [70] Therefore, distribution system operator could enhance the distribution reliability especially at the end of long rural feeder having no backup connections.

7.3.1 Hazardous line sections

During the DSO interviews, it was considered that potentially fault prone line sections could be documented in the system to enhance the fault inference. For example, overhead lines located in the forest vulnerable to high wind, or heavy snow loads or cables prone to excavation could be documented geographically into the system. Automatic fault location function could then use the information to deduce the potential faulty zone. The coloring mode could also be used to assist operator to determine the fault location.

Requirements for the functionality were straightforward operation and effortless visualization of the data. There should also be option to disable the feature from the fault inference, if the data is outdated. Weight of the line parameter of environmental hazard could be adjustable by certainty factors in DMS600 WS fault inference logic. Environment hazard classes need to be configurable by the user. By these means, the Code info definitions can be utilized to store these variables, since the administrator user can modify these from the DMS600 general settings. Table 2 presents the structure of the Codeinfo SQL table and example classes defined.

Table 2. *Hazard classes in the Codeinfo SQL table*

INFOTYPE	CODE	INFO
ENVIRONMENT_HAZARD	1	Forest
ENVIRONMENT_HAZARD	2	Excavation
ENVIRONMENT_HAZARD	3	Faulty network equipment

The information of the hazardous line section is kept updated with DMS600 Network Editor or it can be imported with network data from an external network information system. Environment hazard is defined as a MV line section attribute and updating the value can be done by using the MV Section dialog in DMS600 NE. Even though single line section may cover geographically long distance, it is still narrowed down to a certain disconnector zone. As the DMS600 supports mass update for line sections, certain attribute can be updated to several line sections at once, which reduces the amount of work need to be done. Example modifications to the dialog are described in the Figure 45.

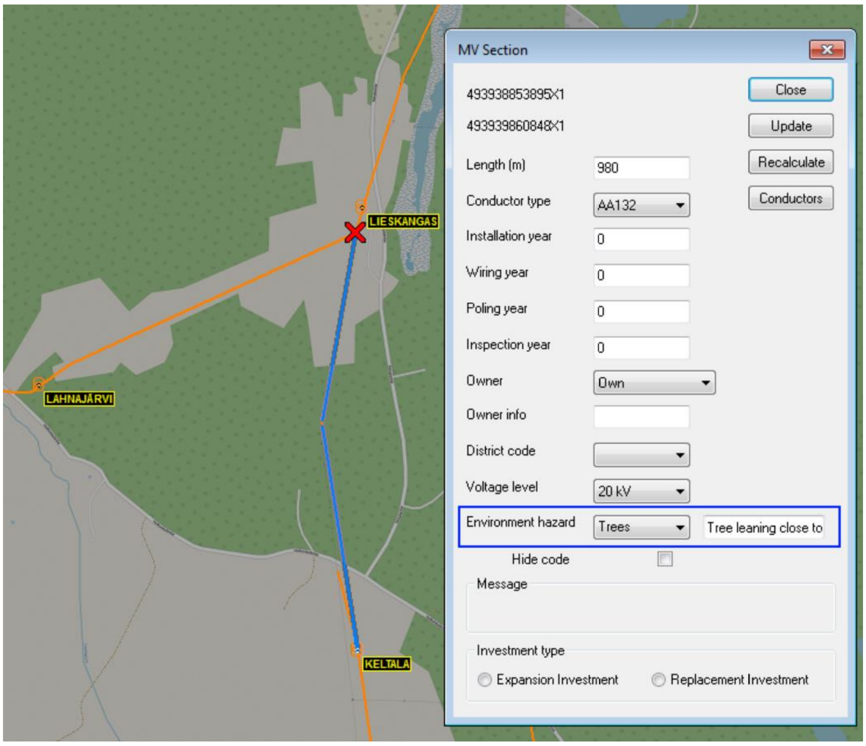

Figure 45. *Environmental hazard addition to the MV Section data form of DMS600 NE*

As presented in the Figure 45, type of the hazard can be selected from the drop-down menu of the MV section dialog. Alongside rather trivial information of the hazard type, free text definition can be attached to the certain attribute. Free text information may contain e.g. excavation work schedule or detailed information of forest conditions, principally for keeping the documentation updated. The hazard attribute could also include date interval to specify the validity of the data. After the time stamp of the hazard has expired, attribute could be automatically deleted, or user could be informed to maintain the information. This would enhance the documentation process and the validity of the data.

Visualization of the hazardous line sections can be turned on from the tool bar of DMS600 NE and WS, to be used for documentation and guidance in network operation. When the visualization is turned on, line sections with hazard documented are highlighted in the main network window. Different classes are visualized with separate colors and the class definitions are visible in the topology legend. Figure 46 presents the main network window and topology legend, with environmental hazard coloring mode enabled.

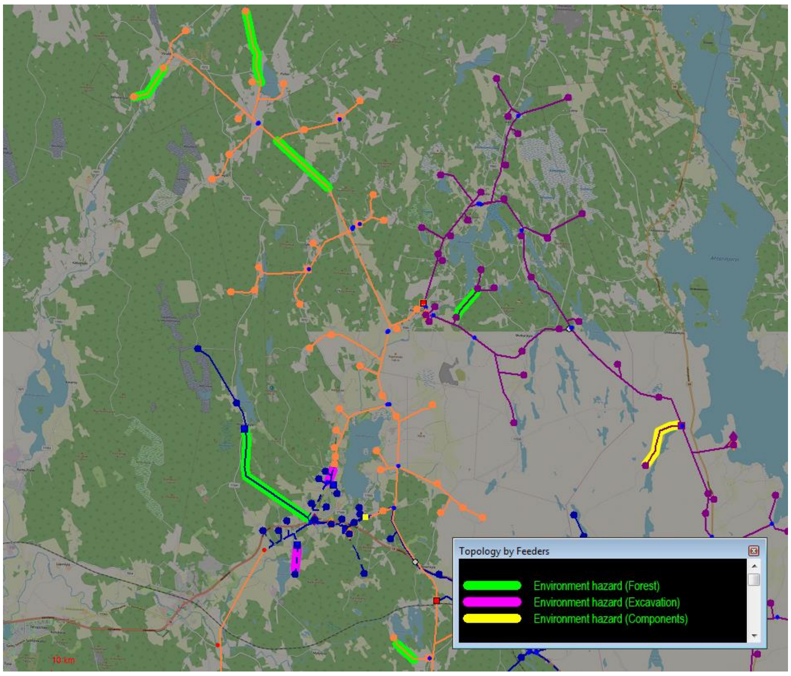

Figure 46. *Highlight coloring of the line sections with environmental hazard value documented*

To specify the information related to certain MV line section, free data object or DMS600 WS note object can be attached to the specific geographical location. Geographical note is beneficial, when the operator is dispatching field crews to isolate the fault by manually controlled disconnectors or locating the fault by field inspection. Free object can also contain text label to provide detailed information about the situation when the network window is zoomed. Example of the free object placement is presented in Figure 47.

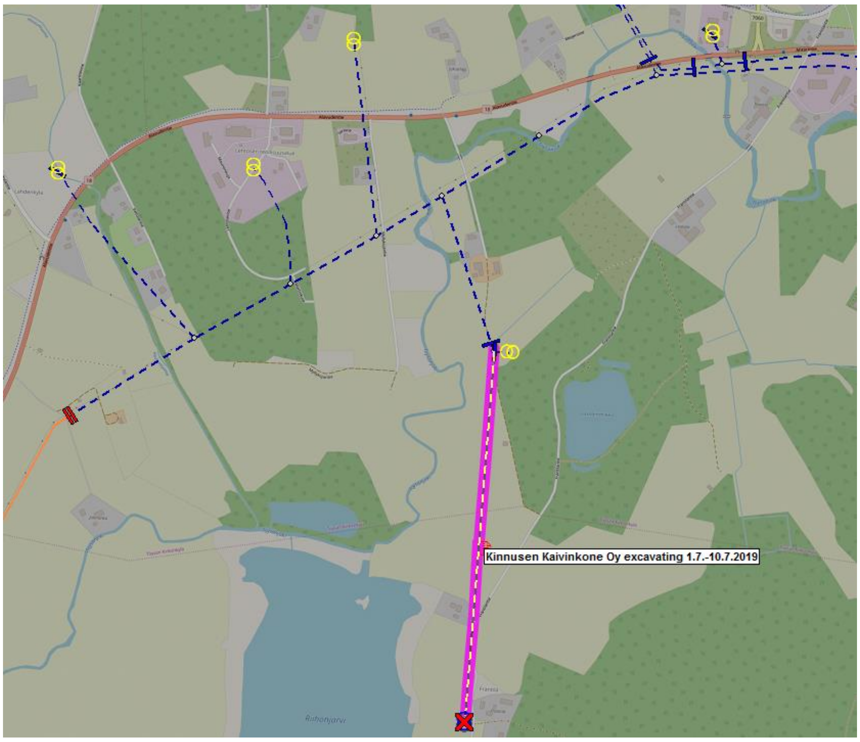

Figure 47. *DMS600 WS note attached to the line section*

Due to changing nature of the environmental conditions, documentation of the line sections to the system may be time consuming and the data can easily be outdated. According to the DSO interviews, inspections and information of the potential environmental hazards may not be received from the actuators in the field or due to lack of manpower inspections may not be documented [58, 62, 64]. Therefore, proper communication between the DSO, contractors and municipalities must be obtained. Also, during occasional condition inspection of line sections and network components, inspection crews could update the information with handheld devices.

8. CONCLUSIONS

While distribution networks are becoming more complex and high distribution reliability is required, automatic functions in daily operation must be introduced. Especially rural distribution network operators do not have the possibility to ensure a fully weatherproof network due to sparsely populated distribution areas, at least in next few decades. According to the DSO interviews, utilization of the existing and constantly increasing amount of network automation with advanced algorithms is seen as one of the key development needs in the near future. The distribution management system along with SCADA provides a powerful platform to implement centralized automation, since the switching state and the topology of the whole distribution network can be analyzed and controlled without high penetration of expensive local automation. This thesis focuses on the demand for the Finnish rural DSOs having long overhead line feeders, and thus the centralized automation is taken into inspection.

Automatic fault location, isolation, and supply restoration (FLIR) functionality streamlines the fault management process by relieving the workload of the network control center operators and improves the efficiency of the fault clearing process. Though FLIR does not affect the number of faults, the total outage duration and thereby the customer outage costs can be decreased. According to the interviews and the literature review, the FLIR is most beneficial at night when the network control center is not full-time operated, and the operation is carried out by a remote operator at home. In that case, automation can carry out or partially execute the fault isolation and supply restoration process before the remote operator is ready to take actions.

During major disturbance situations, DSOs are operating the network with a larger, specially trained organization full time. Due to unusual conditions and multiple simultaneous faults all over the distribution area, the overall situation awareness is emphasized to be extremely important. DSO interviews pointed out that conventional FLIR solution, where automation takes care of the switching operations and supply restoration, may not be beneficial during these conditions. Especially when the switching state of the distribution network is unusual and multiple operators are controlling the network, automation is not wanted to disturb the process and vice versa. A major disturbance FLIR solution is rather preferred to be assisting function providing visualization and optimal switching sequences to operator for execution. One proposed method to accomplish a fluent operation during a disturbance situation is to determine certain operating areas where the FLIR is allowed to operate without disturbing the switching actions performed by operators.

The current version of ABB MicroSCADA Pro DMS600 distribution management system already includes solution for automatic fault isolation and supply restoration, which yet is not feasible enough according the DSOs. Since the functionality is solely based on a fault distance calculation and fault inference e.g. by fault indicators, high number of faults cannot be managed due to lack of initial data. In Finnish distribution networks, where the neutral is isolated or compensated, earth faults cannot be located by fault distance calculation due to low magnitude fault currents. Also fault indicators have been discovered to be too unreliable and expensive for large scale deployment. Therefore, the operator usually performs trial switching, where a substation circuit breaker is closed against a suspected fault, disconnector zone one by one. Combining the current fault inference by relay measurements and fault indicator data with trial switching sequence will improve the performance of the FLIR solution as larger number of faults can be handled.

The main objective for this thesis was to gather development needs and ideas for the FLIR functionality by conducting semi-structured interviews for Finnish DSOs operating in rural distribution areas. Motivation of the research was to gather information and basic principles of MV network fault isolation and supply restoration performed by the human operator and find out the most important requirements and restrictions for the functionality. The interviews also included general description of the actions taken to meet the tightening distribution reliability requirements. The interview process produced a variety of development needs and ideas, of which introducing the trial switching sequence alongside the current fault inference and simultaneous execution of FLIR cases were the most desired. The research also pointed out that easy configurability and straightforward user interface were the key elements in a comprehensive solution. The most important development needs and ideas have been taken into closer examination and written down for the research and development team of MicroSCADA Pro DMS600.

Constantly developing distribution automation and increasing penetration of distributed energy resources provide a possibility for more comprehensive automation solutions. Two-way communication between customer automation and DER allows a feeder load flow to be reconfigured to support supply restoration via backup feeders. Centralized communication with microgrid controllers enables fast supply restoration to rural areas where backup connections cannot be utilized. While multiple communication flows and an increasing amount of data are introduced to the system, more sophisticated data management tools and algorithms, such as neural networks and genetic algorithms must be considered to improve the efficiency of automatic fault management.

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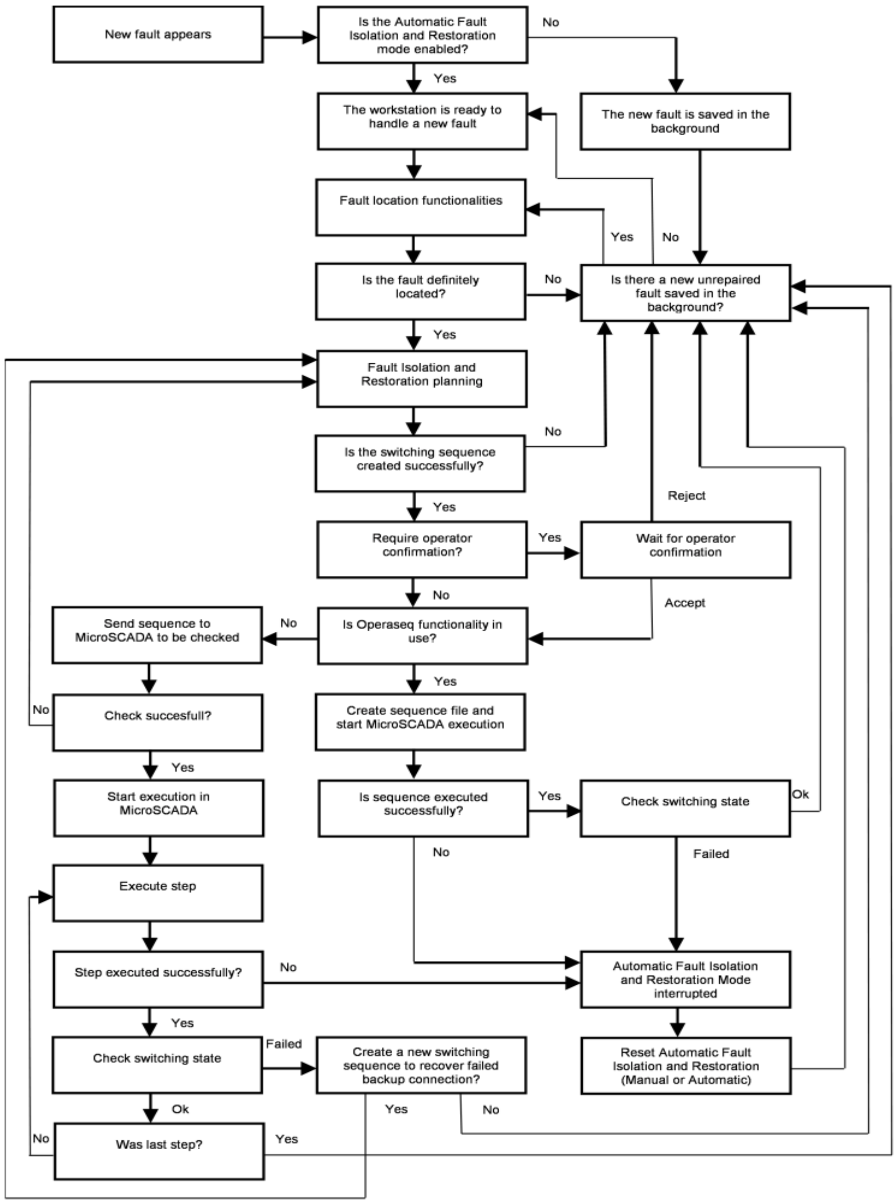
APPENDIX A: THE CURRENT PROCESS FLOW OF THE AUTOMATIC FAULT ISOLATION AND RESTORATION SEQUENCE



The process flow of the Automatic Fault Isolation and Restoration mode in MicroSCADA Pro DMS600 [11]

APPENDIX B: QUESTIONNAIRE FOR CUSTOMER INTERVIEWS

1. **Basic information about the distribution network**
    a. Present the length of the distribution network and cabling degree. How much is the relation between networks locating in the town plan area versus rural area?

    b. How much remote-controlled disconnectors and sectionalizing circuit breakers are installed in the network?

    c. Have fault detectors been installed in the network? If so, how reliable do you consider the operation during a fault?

    d. Is there any distributed generation or energy resources capable of islanded operation or supporting the supply restoration?

    e. What are the future plans to enhance the distribution reliability?

2. **Automatic functionalities**
    a. How beneficial you consider the automatic fault isolation and supply restoration in different situations: single fault, multiple simultaneous faults and major power disruption? (Day / Night)

    b. In your opinion, is automation allowed to perform trial switchings independently?

    c. Is automation allowed to perform supply restoration independently utilizing backup connections?

    d. In what situations automatic functionalities should be restricted of fully prevented?

3. **Describe the fault location, isolation and supply restoration performed by the operator**

    a. Fault Location

    i. According to the current situation, how often is the fault possible to locate accurately? Do you consider the location functionality reliable?

    ii. If the fault cannot be located or there are multiple candidates for the fault location, how the operator deduces the most potential fault location? Describe the data sources utilized.

b. Trial switching

i. In what situations trial switchings are not performed?

ii. Which trial switching method is preferred: bi-section or zone-by-zone rolling?

iii. How is the trial switching method chosen?

c. Supply restoration

i. Are there situations, when operator will not utilize back-feed connections even if calculated constraints are not violated?

ii. If there are multiple acceptable back-feed connections, how the operator chooses one to be used?

iii. How normal situation differs from major power disruption according to utilizing the back-feed connections?

4. Development needs in DMS system

a. What are the development needs in current fault location, isolation and supply restoration functionalities?

b. What existing or new functionalities do you consider the most important for the system?

APPENDIX C: REQUIREMENTS FOR THE FLIR FUNCTIONALITY ACCORDING TO THE CUSTOMER INTERVIEWS

General functional requirements

1. Automatic Fault Location, Isolation and supply Restoration (FLIR) sequence shall not disturb the normal operability of the distribution network:
    a. Performance of the HMI shall be obtained when FLIR is running.
    b. Operator can handle faults when FLIR is running.
    c. Responsibility of a fault can be switched to operator without stopping the overall FLIR functionality.

2. DMS600 Workstation user interface must include easy to access kill switch to stop automatic sequence in case of a dangerous situation.

3. FLIR must be able to handle simultaneous faults in separate operation areas:
    a. Separate areas prevent FLIR sequences to interrupt each other.
    b. FLIR can be set as responsible of a certain area while operators handle rest of the distribution network.

4. FLIR must be stopped due to abnormal situation to avoid electrical safety risk
    a. Switching device indicates abnormal position
    b. Position indication of a switching device is not received

Fault location and isolation

5. Initial data must be used to infer the fault location as the primary method for fault location:
    a. Fault distance calculation
    b. Existing fault inference model of the DMS600

6. If an exact fault location cannot be deduced, trial switching sequence shall be applied:
    a. Coarse division of the feeder using bi-section method.
    b. Remaining area traversed by zone-by-zone rolling method to avoid unnecessary tripping.

7. If a secondary fault is found after the first RCD isolation, FLIR should continue with zone-by-zone rolling method to isolate the fault.

Supply restoration

8. DMS600 WS checks possible constraint violations before restoring the supply
    a. Loading condition
    b. Voltage drop
    c. Short-circuit protection
    d. Earth fault protection

e. Earth fault current compensation
f. Parallel operation of primary transformers

9. If healthy upstream branch can be isolated from the main supply route during trial switching sequence, supply shall be restored from adjacent feeder

10. Automatic restoration mode shall be disabled from the FLIR settings. E.g. in major disturbance situation to:
    a. Prevent outages in adjacent feeder in case of multiple faults
    b. Not potentially interrupt fault handling process of several human operators

FLIR settings

11. FLIR settings must be easily configurable by the user (e.g. no unnecessary rebooting of Windows services).

12. Trial switching sequence can be enabled according to time of the day

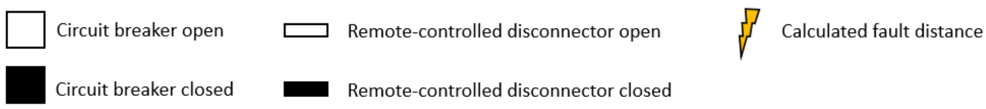
13. FLIR should have multiple levels of settings. Settings are inherited from upper level:
    a. Overall FLIR functionality:
        i. FLIR enabled
        ii. Disturbance mode
    b. Area level:
        i. FLIR enabled
    c. Substation level:
        i. FLIR enabled
    d. Feeder level:
        i. FLIR enabled
        ii. Trial switching sequence enabled
        iii. Can be used as a backup connection

FLIR monitoring

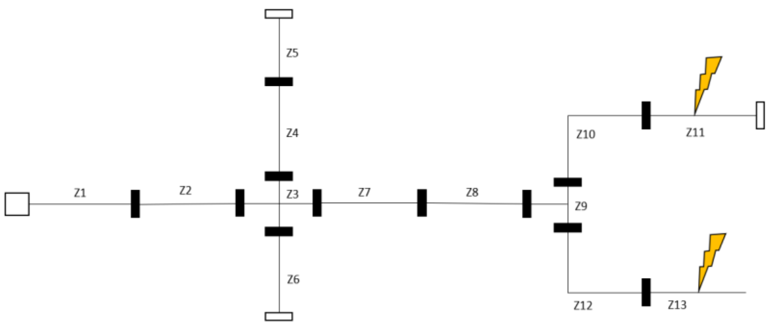
14. Automatic switching actions should be clearly visible in a list to ensure fluent switchover from automatic mode to manual.

15. Errors and malfunctions must be highlighted and explained to the user, for example:
    a. Error in communication
    b. Switch in abnormal state
    c. Software error (e.g. connection timeout, database error)

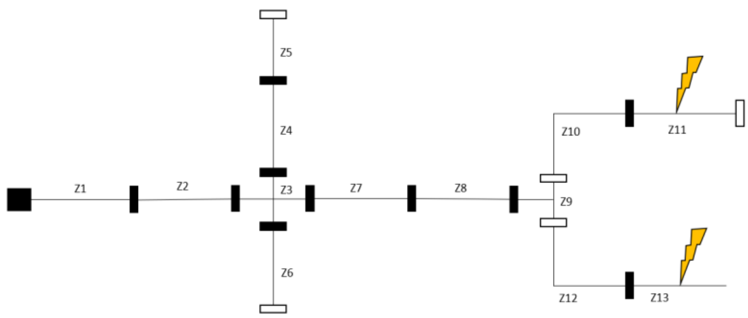
APPENDIX D: EXAMPLE OF TRIAL SWITCHING SEQUENCEWITH SEVERAL FAULT DISTANCE CALCULATIONS



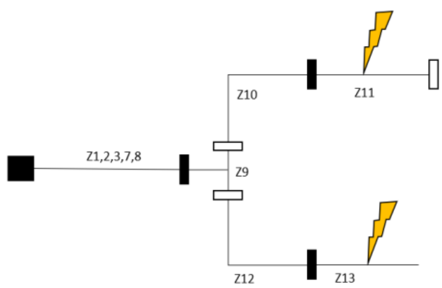
1. Fault distance calculated in RCD zones Z11 and Z13



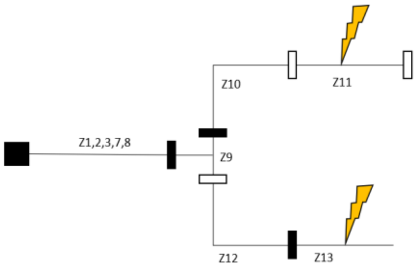
2. RCDs in the common branch isolating both suspected zones are opened, and substation circuit breaker is closed to supply upstream of the feeder.



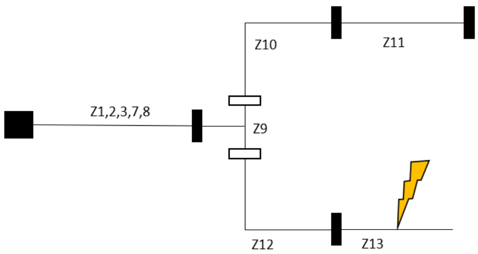
3. To avoid additional short breaks, branches Z4 - Z5 and Z6 are re-supplied with open backup connections and isolated from the main supply route. Feeder can be the reduced for zone-by-zone rolling.



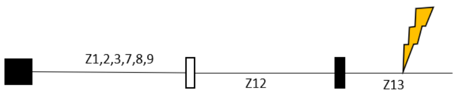
4. To minimize short breaks, branch Z10 - Z11 is examined first because of the open backup connection. Zones Z10 and Z11 are re-supplied one by one from the up-stream direction.



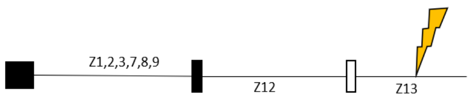
5. If the circuit breaker stays closed, the branch can be stated healthy, and supply can be restored from the open backup connection and isolated from the main supply route



6. Feeder model is further reduced, and the fault is suspected to be in branch Z12 - Z13.



7. RCD isolating the zone Z13 is opened and zone Z12 is re-supplied. If the circuit breaker stays open, concluded faulty zone is Z13.



8. There is a chance that fault has disappeared during the isolation sequence. Normally operator considers verifying the fault by performing additional trial switching to the suspected zone. If the circuit breaker still stays open, fault can assume to be cleared by itself.