TAMPEREEN TEKNILLINEN YLIOPISTO
TAMPERE UNIVERSITY OF TECHNOLOGY

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DISTRIBUTION AUTOMATION LABORATORY ASSIGNMENTS FOR STUDENTS IN TAMPERE UNIVERSITY OF TECHNOLOGY

Master of Science Thesis

Examiner: prof. Sami Repo
Examiner and topic approved by the Faculty Council of Computing and Electrical Engineering March 2017

ABSTRACT

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Distribution automation is a fundamental part of distribution network operation. In Finland, the goal is to increase the number of automated functions in a distribution network, because of the constantly tightening requirements for decreasing the duration of outages. For students, who study power engineering, it is beneficial to understand the possibilities of distribution automation.

In Tampere University of Technology, the course Distribution Automation ensures the understanding of the fundamentals of distribution automation and network operation for students. The course includes lecture subjects, written exercises and laboratory assignments.

The main objective of this thesis is to improve and update laboratory environments of distribution automation for the course Distribution Automation. The laboratory environments should help students understand distribution network protection, the role of DMS and SCADA system, and smart metering.

This thesis examines previous laboratory implementations on the course and distribution automation in general. The laboratory environments and students' feedback from previous laboratory implementations are presented in this thesis. The chapter on distribution automation displays information about distribution network protection, SCADA and DMS systems, AMI system and protocols. The distribution network protection section presents basic needs and regulations for distribution network protection. SCADA and DMS section introduces functionalities of these systems whereas smart metering section describes AMI system naming and structure. Protocols and standards section describes IEC 104, IEC 61850, OPC, DLMS/COSEM, object oriented information models and OSI model communication structures.

As a result of this thesis, implementations from two different laboratory environments are introduced. The first laboratory implementation includes distribution network protection and IEDs. The second laboratory implementation includes a smart meter, DMS and SCADA systems, and remote communication between the control center, the substation and the smart meter.

TIIVISTELMÄ

Tommi Leskinen: Jakeluverkon automaation laboratorioharjoituksia opiskelijoille Tampereen Teknillisessä Yliopistossa
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Suomessa jakeluverkon automaation määrä kasvaa, koska vaatimukset keskeytysaikojen lyhentymiseksi kiristyvät. Sähköverkkoja opiskelevien opiskelijoiden onkin tärkeää ymmärtää sähköverkon automaation ratkaisuista ja sen tuomista mahdollisuuksista verkon käytössä kuten vikojen selvityksessä.

Tampereen Teknillisessä Yliopistossa (TTY) opiskelijat voivat tutustua jakeluverkon automaatioon kurssilla Distribution Automation. Kurssin sisältöön kuuluu luentoja, kirjallisia harjoitustöitä ja laboratorioharjoituksia.

Tämän tutkielman tarkoituksena on kehittää ja uudistaa jakeluverkon automaatiota käsittelevän kurssin laboratorioympäristöjä. Töiden tarkoituksena on tukea opiskelijoiden ymmärrystä aiheista jakeluverkon suojaus, käytöntukijärjestelmä ja SCADA, ja älykkäät sähkömittarit.

Tutkielmassa esitellään aikaisempien laboratoriotöiden rakenne ja opiskelijoiden antamaa palautetta kurssin toteutuksesta. Jakeluverkon automaatiota käsittelevässä kappaleessa tutustutaan jakeluverkon suojaukseen, käytöntuki- ja SCADA-järjestelmään, älykkäisiin mittarijärjestelmiin ja protokolliin. Jakeluverkon suojauksessa tutustutaan suojauksen vaatimuksiin ja toteutuksen käytäntöihin. Käytöntuki- ja SCADA-järjestelmää käsiteltäessä tutustutaan järjestelmien toiminnallisuuksiin ja rooliin verkon käytössä. Älykkäiden mittareiden tapauksessa tutustutaan AMI-järjestelmän termistöön ja rakenteeseen. Protokolliin ja standardeihin tutustuttaessa esitellään olio-malli ja tietoliikenteen OSI-mallin, joiden kautta tutustutaan työn kannalta tärkeisiin standardeihin ja protokolliin: IEC 61850, IEC 60870-5-104, OPC ja DLMS/COSEM.

Työn tuloksena kehitettiin kaksi laboratorioympäristöä kuvaamaan jakeluverkon automaatiota pääasiassa opiskelijoille. Ensimmäinen laboratorioympäristö kuvaa jakeluverkon suojauksen toimintaa ja kennoterminaalireleitä. Toisessa laboratoriossa esitellään älykäs sähkömittari, käytöntukijärjestelmä ja tiedonsiirtoa jakeluverkon käyttökeskukselta sähköasemalle ja älykkäälle mittarille.

PREFACE

This thesis is written for Laboratory of Electrical Energy Engineering in Tampere University of Technology. In addition to laboratory implementations, during this thesis was created laboratory instructions and REF615 COMTRADE file reader.

I would like to thank JE-Siirto Oy, Tampereen Sähköverkko Oy and Elenia Oy for possibility to visit these companies during my thesis. I would like to thank Juhani Rouvali for possibility to see what kind of distribution automation exercises students have in university of applied sciences. In addition, I would like to thank all ABB's experts who helped me with REF 615 IEDs, SCADA and DMS systems. Specially, I would like to thank my supervisor Sami Repo from feedback and the possibility to do thesis from an interesting subject.

I want to thank my family for support during my studies. And last, but not least, thanks to my girlfriend Henni for inspiring and supporting me while I was writing this thesis.

Tampere, 16.3.2018

Tommi Leskinen

CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF SYMBOLS AND ABBREVIATIONS

AMI	Advanced Metering Interface
AMR	Automatic Meter Reading
ASDU	Application Service Data Unit
CIS	Customer Information System
COMTRADE	Common format for Transient Data Exchange for power systems
COSEM	COmpanion Specification for Energy Metering
DLMS	Device Language Message Specification
DMS	Distribution Management System
DSM	Demand Side Management
DSO	Distribution System Operator
GOOSE	Generic Object Oriented Substation Event
GTAO	Gigabit-Transceiver Analog Output
GTFPI	Gigabit-Transceiver Panel Interface
HDLC	High-Level Data Link Control
ICT	Information Communication Technology
IED	Intelligent Electric Device
IP	Internet Protocol
IT	Information Technology
LED	Light Emitting Diode
MDMS	Meter Data Management System
MMS	Manufacturing Message Specification
NIS	Network Information System
OBIS	OBject Identification System
OPC UA	OLE for Process Control Unified Architecture
OSI	Open Systems Interconnection
PLC	Power-Line Communication
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SLD	Single Line Diagram
SS	Secondary Substation
TCP	Transmission Control Protocol
TUT	Tampere University of Technology
UI	User Interface

C_{0j}	Capacitance between line and ground for faulted feeder
C_0	Capacitance between line and ground for network
I_f	Fault current
I_k	Three-phase short circuit current
I_{k2}	Two-phase short circuit current
I_0	Residual current
k	Multiplier for grounding conditions
R_e	Earthing resistance
R_f	Fault resistance
U_0	Residual voltage
U_e	Earthing voltage
U_{ph}	Phase voltage
U_{tp}	Touch Potential
Z_{tot}	Total impedance
ω	Angular frequency

A	Ampere
V	Voltage
VA	Volt-ampere
Ω	Ohm

.

1. INTRODUCTION

Society is reliable on sustainable electricity delivery. Electricity Market Legislation give requirements for distribution system operators (DSOs) from allowed outage durations in Finland. An act, towards shorter interruption times for consumers, is increasing the amount of automated functionalities in the network operation. These automated functionalities are known as distribution automation. Due to the key role of distribution automation in the distribution network operation, it is important that students have an understanding from the basic principles of distribution automation.

The laboratory of Electrical Energy Engineering in Tampere University of Technology (TUT) offers a course on distribution automation, in which students learn the basics of distribution automation. The course includes lectures and laboratory assignments. The purpose of this thesis is to improve the laboratory environment for the course.

1.1 TUT's course Distribution Automation description

The course Distribution Automation provides information about automated functionalities within the distribution network operation and control. Students will understand operation principles and the benefits of distribution automation, and the structure and functions of automation systems. They will learn the basics from relay protection and the future trends of distribution automation. The course includes lectures, writing assignments and laboratory assignments.

Laboratory assignments demonstrate the practical system and visualize distribution automation for students. During the laboratory assignments students get in physical contact with distribution network automation. Laboratory assignments are based on lecture subjects, writing assignments and pre-laboratory assignments.

1.2 Focus and Objectives of the thesis

This thesis focuses on updating and creating new laboratory assignments on distribution automation and improving the laboratory environment. Laboratory assignments mainly concern students. A laboratory assistant is present during exercises. The laboratory of Electrical Energy Engineering has an environment for distribution network simulations, and distribution automation devices. The scope of the laboratory assignments must be planned so that TUT's requirements for course credits and implementation are fulfilled.

The course area is divided into three categories in this thesis. These categories are intelligent electric devices (IEDs) and protection, distribution network operation and control, and smart meter and its possibilities. The operation and control part is new and need to be integrated to laboratory exercises. Operation and control will include Distribution Management System (DMS) and System Control and Data Acquisition (SCADA) system. The laboratory pre-assignments and assignments in the laboratory will be kept similar as in the earlier laboratory implementations. The main focus is on updating the laboratory environments. Laboratory instructions will be developed for assistants. These instructions will in turn include information on building the laboratory environment and instructions on how to operate with students during the laboratory assignments.

2. PREVIOUS LABORATORY ASSIGNMENTS

This chapter focuses on the background of this thesis. Chapter presents description from both previous laboratory systems, student assignments and technical information from laboratories.

The first laboratory exercise concentrates on relays. The second laboratory presents low voltage automation in the distribution network.

Both laboratories use Real Time Digital Simulator (RTDS) to distribution network simulation and describing interaction with distribution automation. RTDS is capable of simulating power network in real time.

2.1 Substation automation laboratory

The idea of the laboratory is to get familiar with the distribution network protection and relays interaction in the distribution network. The distribution network is simulated with RTDS and the simulated network consists of primary substation, 110kV network, four medium voltage feeders and loads that are connected directly to medium voltage network. Laboratory relays are located on substations busbar and a feeder.

System structure of the laboratory is presented in Figure 1 below. System includes RTDS, amplifier, feeder protective relay and control unit PC for RTDS. In addition to equipment in the figure, the laboratory environment also includes busbar protective relay and configuration PC, from which busbar protection relay simulates busbar protection and configuration PC is for updating relays configurations. In Figure 1 PC controls the simulation environment as well as presents the network model and sends commands to RTDS. RTDS executes network model simulation and simulated voltage and current values are sent through RTDS analog outputs to amplifier where the amplified current and voltage values are taken to protection relays. Relays breaker operations are sent through hardwired connection to RTDS digital input card. Feeder protection relay have hardwired connection to busbar protection relay for a blocking message.

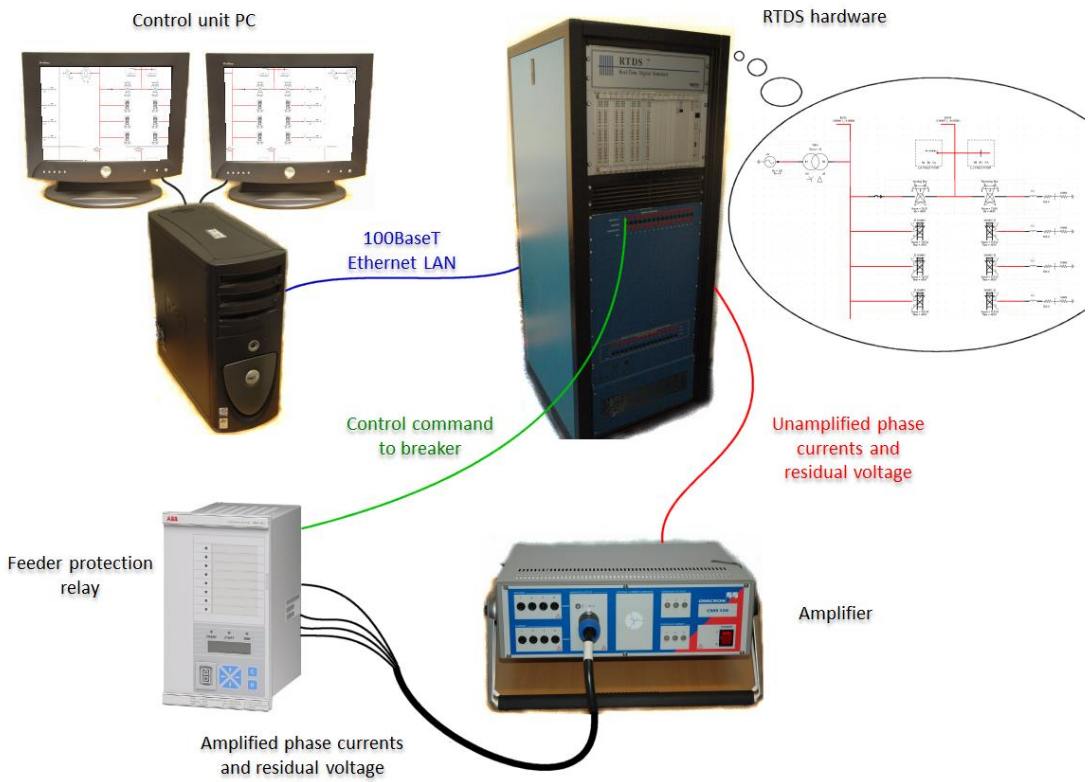

Figure 1. *Simulation environment.*

The laboratory exercise tasks are mostly concentrated on distribution network protection. The tasks are detecting the operation of busbar protective relay and feeder protective relay. Relays' detect faults and trip when effective value of protection function is exceeded.

2.1.1 Technology and simulation environment

Substation automation laboratory system consists of two ABB REX521 relays, RTDS simulator, control unit PC, relay configuration PC, amplifier and three different computer programs. Programs are RSCAD, CAP501 and Vampset.

REX521 is design to feeder protection in medium voltage level and it has not been ABB's active product since 2012 [1]. REX521 M01 is used as feeder protective relay and REX521 H04S in busbar protection which is enriched version from feeder protection REX. REX devices' disturbance recordings are read and settings are configured through optical adapter with 19,2kB/s data transferring speed. 19,2kB/s is slow speed for configuration and reading files when comparing to more advanced REF protection devices that has 10MB/s to 100MB/s data transferring speed [2].

Both REX521 devices have three protection functions each. Two of these functions are for overcurrent protection: low set, and high set current protection. Feeder protection device low set stage settings are 56A rated current and 400ms operation delay, and for high set stage the settings are 1400A rated current and 50ms operation delay. For busbar protection relay low set stage current setting is 225A rated current and 600ms operation delay and for high set stage current limit is 1600A and operation delay is 200ms. The high set stage current protection of the busbar protection is possible to block from feeder protection device with hardwired connection. Protection functions tripping signals are send to RTDS Gigabit-Transceiver Front Panel Interface (GTFPI) card. The protection functions tripping is presented with Light Emitting Diodes (LEDs) on relays' panel and faults are recorded to disturbance recordings.

Third protection function is earth fault protection. Earth fault protection functions, at feeder and busbar devices, are designed to operate with 1000Ω fault resistance. Earth fault protection settings for feeder is 4A (2,1% from nominal current) residual current and 400ms operation delay. At busbar protective device, protection settings are 6kV (30% from nominal voltage) residual voltage and 600ms operation delay.

REXs' configurations and disturbance recordings are handled with configuration PC. Configuration PC is used for relays' configuration and reading disturbance recordings. Disturbance recordings are read with CAP501 and disturbance recordings are downloaded and analyzed with Vampset program. Configuration PC uses Windows XP, but Windows XP support has ended, which makes the system unsecure.

The distribution network is modelled with RTDS simulator in the laboratory. Control unit PC run an RSCAD software which is the program used for running RTDS simulations. From RSCAD's tools were used Draft, T-line and Runtime. Simulation network model is developed with Draft module, network parameters are modified with T-line and Runtime module controls and monitors simulations.

The simulated network is a distribution substation, which has four feeders and one input from high voltage network. Figure 2 below presents the simulation model. The model consists of four outgoing feeders that have AF87 overhead line model blocks, and one of the feeder and busbar include fault locations. The network is unearthed system, although the primary transformer has connection to ground (the grounding resistor is 100kΩ), and the voltage source has unlimited short circuit current. Circuit breakers are located at the end of input feeder and at the beginning of one outgoing feeder. At the end of each feeder are located 1,5MVA three phase loads.

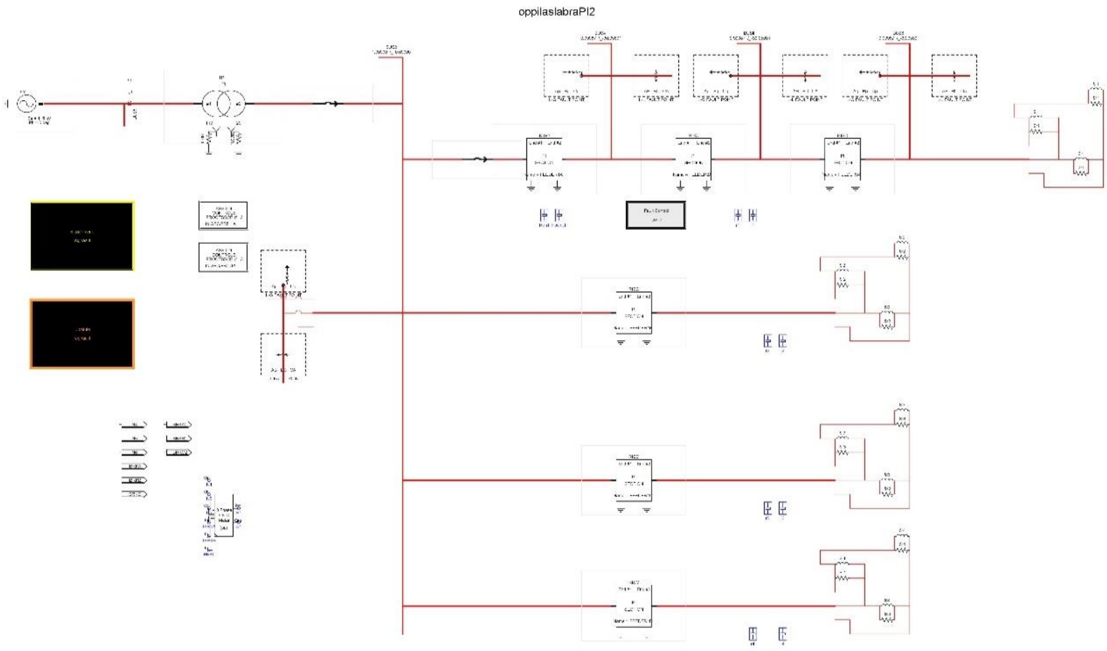

Figure 2. *Simulation model.*

The network model's circuit breakers are controlled with circuit breaker control logic. Control logic is presented in Figure 3 below. The control logic receives relays' tripping signals trough GTFPI card from which tripping signals are converted to logical form with world-to-bit block that is followed by signal generators that trigger when blocks receive signals from relays. Signal generators are followed by delay blocks, to present operation time of circuit breakers. From delay blocks signals are forwarded to circuit breaker models.

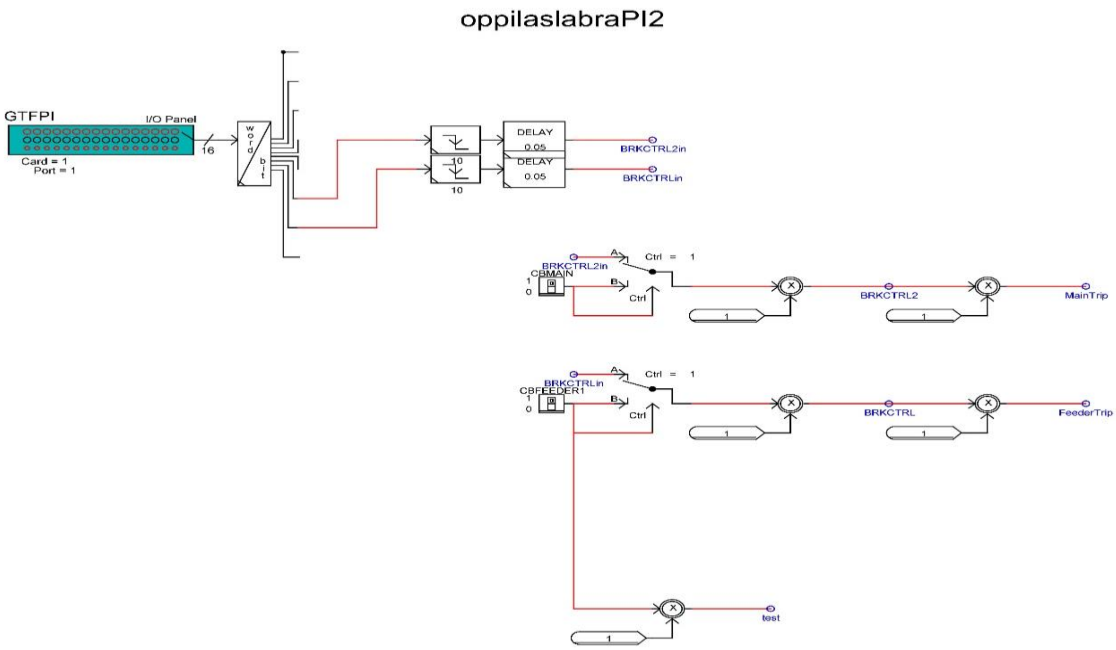

Figure 3. *Circuit breaker control logic.*

Voltage and current measurements are taken through measurement logic to relays from the network model. Measurement logic is presented in Figure 4 below. The top circuit in the figure is for analog voltage and current outputs to relays through Gigabit-Transceiver Analog Output (GTAO) card. Residual voltage is calculated from the sum of measured values and multiplied with constant 0,3333, whereas residual current is calculated from sum of phase currents. The figure's bottom circuit is for sensor measurements that are needed for sensor inputs of busbar protection relay.

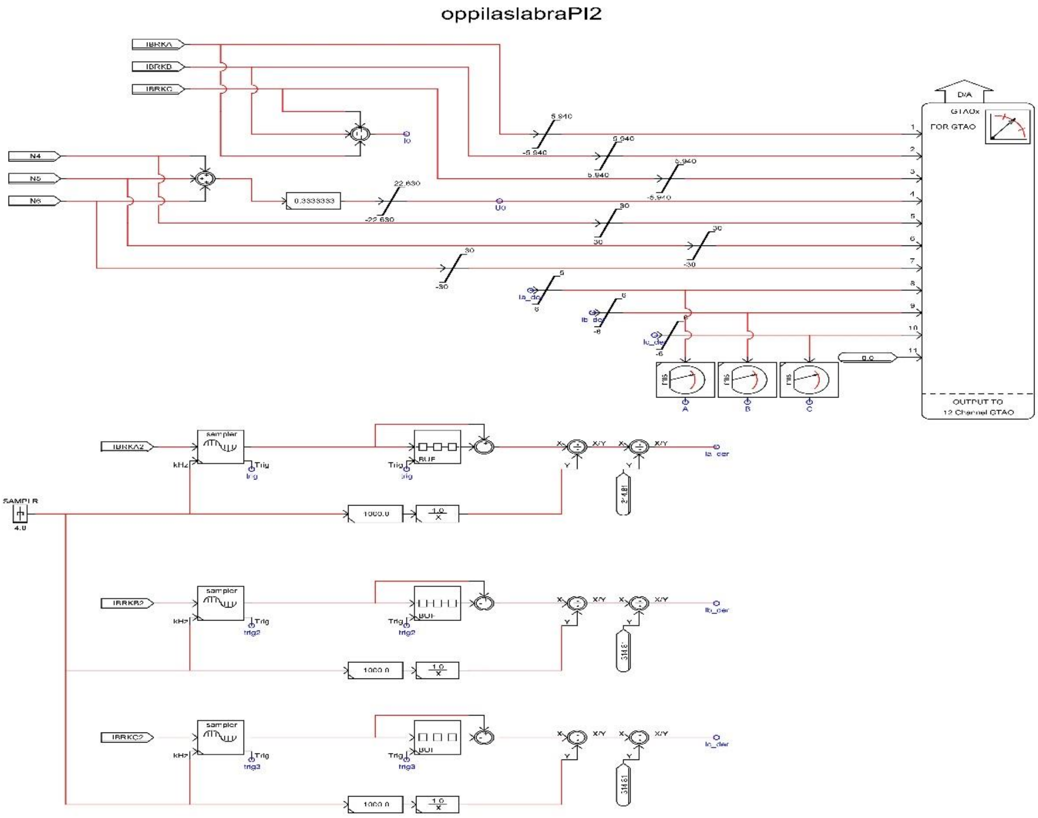

Figure 4. *Voltage and current outputs.*

Figure 4 measurements are forwarded with physical GTAO to relays. GTAO card outputs are connected to an OMICRON amplifier and busbar protective devices. The amplifier is connected to protective devices.

2.1.2 Student assignments

Students' assignments consist of pre-laboratory assignments and laboratory assignments. In the pre-laboratory assignments students get knowledge about laboratory area before participating in the laboratory.

In the pre-laboratory assignments, students draw relay connections, calculate network parameters and get familiar with computer programs, which are used in the laboratory exercise. Students draw relay connections, and calculate load current, short circuit and earth fault values. Short circuit currents are calculated in cases where there is three-phase short circuit in beginning of the feeder and phase-to-phase short circuit in the end of the feeder. Earth-fault is calculated with 1000Ω fault resistance between line and ground. Calculated currents are then used to set operation stages for protective devices.

Laboratory exercise begins with connecting the feeder protective relay and setting its parameters. Parameters are set according to the values which are calculated by the students during the pre-laboratory assignments. After connecting relay and setting configuration, students simulate earth faults and short circuit faults in the network. Simulations are monitored and analyzed with control unit PC and disturbance recording software at configuration PC. During the simulations students analyze protection sensitivity, selectivity, back-up protection and blocking signal function. Last exercise investigates how changing of feeder length does affect to feeder protective relay operation.

2.2 Smart meter laboratory

The second exercise presents smart meter as a part of distribution automation. The idea of the exercise is to describe smart grid, and low voltage automation.

Figure 5 below shows laboratory system. The system has one smart meter, RTDS, amplifier and control unit PC. In addition to devices in the figure, the laboratory environment includes also secondary substation (SS) master unit, SCADA computer and communication network. The laboratory network model consists of high voltage, medium voltage and low voltage network. Network loads are connected to low and medium voltage networks. Smart meter is located on low voltage side, and smart meter measures phase quantities and sends data to SS. SS computer stores smart meter data and forwards commands from control PC to the meter. The SS computer presents decentralized computing.

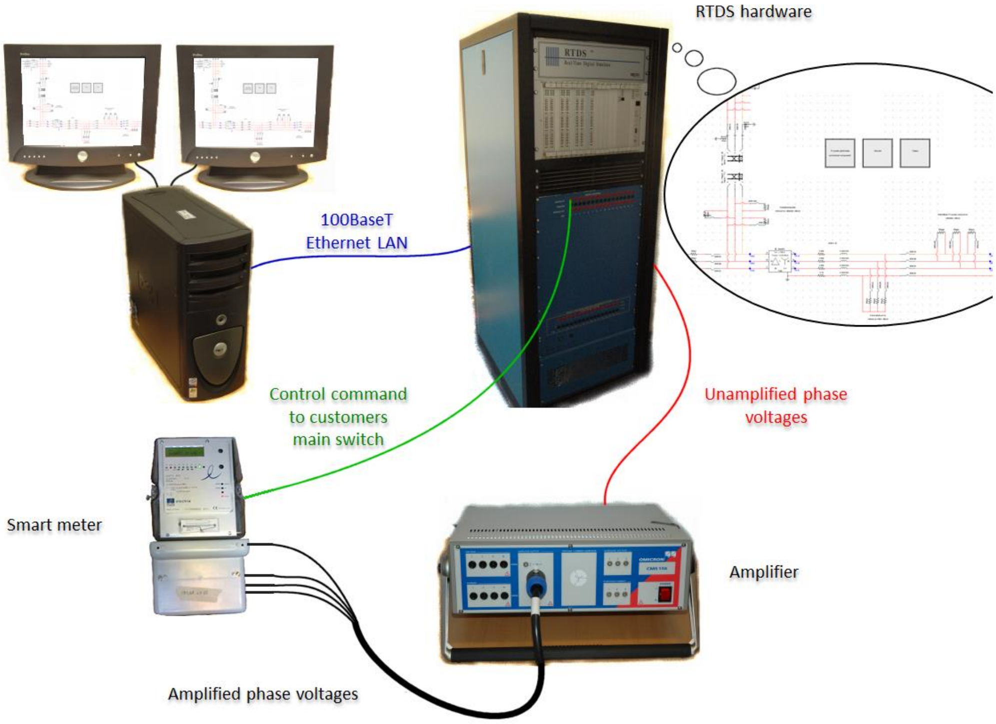

Figure 5. *Laboratory two environment.*

2.2.1 Technical information and simulation environment

The second exercise has same distribution network simulation environment as the first laboratory. The second laboratory system consists of RTDS environment, smart meter, SS, SCADA and information communication technology (ICT). ICT consists of smart meter, two Power-Line Communication (PLC) modems, two switchers, low voltage SCADA and SS computer.

Smart meter is Laatuvahti by MxElectrix. Smart meter measurement inputs are from RTDS GTAO card. The GTAO card is connected to the amplifier and the amplifier's outputs are connected to the meter. GTAO card output voltages are limited, because the amplifier cannot amplify safely voltages that are over 250V. The mart meter has ability to send alarms, measuring information and control signal which is send to RTDS GTFPI card. From smart meter alarms, available alarms are changed phase order, neutral conductor and fuse blown. From measurements are provided voltage, current, active and reactive power, and harmonics information.

ICT connects the low voltage system, SS and information system together. Laboratory ICT implementation uses two network switches where smart meter is connected to one switch and low voltage SCADA, and secondary substation PC to another.

SS computer has Ubuntu 12.04 operating system. Support for the distribution ended in 28.4.2017. SS receive information from smart meter and writes it to its database where information is then analyzed. Database uses IEC 61850 information model naming and IEC 61850 Manufacturing Message Structure (MMS) protocol in communication to SCADA system.

Low voltage SCADA is iControl's and ran on virtual Windows XP. The main operating system is Windows 7.

Network model in laboratory consists of medium voltage network and low voltage network. All faults are simulated in the low voltage network. Model of the low voltage network is in Figure 6 below. The low voltage network is three-phase system with neutral conductor. Faults are simulated with breakers and measured low voltage load is located at the end of the feeder. The load and grounding resistances can be modified with sliders.

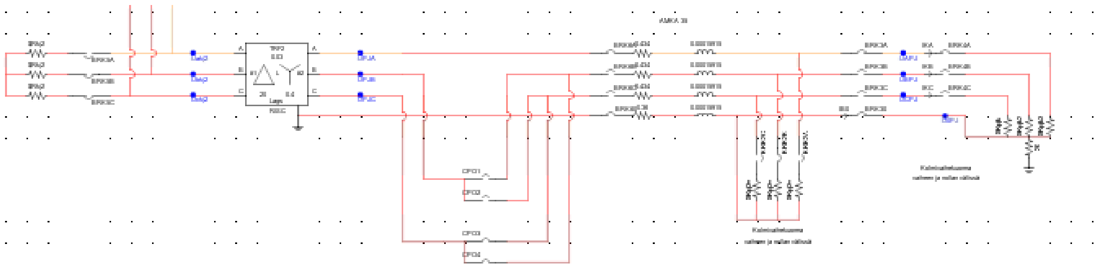

Figure 6. *Low voltage network model.*

2.2.2 Student assignments

In the assignment students simulate normal conditions and fault conditions in the low voltage network. In the pre-laboratory assignments, students calculate voltages in several load conditions, and during the laboratory, students monitor the smart meter.

In pre-laboratory assignments students use a Matlab tool to calculate voltage unbalance in normal and neutral fault situations in the low voltage network. The Matlab tool is developed in TUT. To use the tool in the low voltage network calculation, user needs to provide initial network and load information. The network information includes high voltage, medium voltage and low voltage network resistances and inductances. The low voltage load information includes load impedance and wye point grounding resistance. The default source voltage is 230V phase voltage and 120 degrees difference between phases in the tool. As a result, the tool produces phase voltage and neutral voltage vectors and polar forms from calculations. After the calculations, students are asked to design alarm levels for the smart meter.

In the laboratory exercise, students use calculated values for simulations and detect how smart meter, control unit, database and SCADA present the situations. Students also detect how different kind of low voltage side faults are seen in SCADA, control unit and smart meter.

2.3 Course feedback

Feedback gathered from students has a vital role when improving course content. In TUT, course feedback is collected with Kaiku system. For this thesis, also external feedback was collected regarding course content and laboratories. Results from both, Kaiku feedback and external enquiry, are presented in this chapter. External feedback was collected from last two implementations. Last two implementations where held during the spring 2017 and the spring 2016. At the 2017 implementations there were 63 participants and at the 2016 implementation there were 41 participants.

At TUT, course feedback is mandatory. Students see their grades after giving course feedback. Typical Kaiku form includes multiple choice questions and few open fields. It is not mandatory to answer to any multiple choice question or fill any of open fields. In this chapter open field feedback is analyzed. There were approximately 12 answers to each open field questions.

External enquiry was sent for students by e-mail. 12 answers were collected. Enquiry included questions about course content and laboratory implementations. Enquire contained multiple choice and open field question.

2.3.1 Kaiku feedback

This part examines open field questions from Distribution Automation course Kaiku feedback. The questions of Distribution Automation course were as follows; “What worked well during the course?” and “How would you develop the course?” Those, who gave course feedback in Kaiku, thought that the course was interesting and laboratories were important.

At spring 2017 implementation, students felt that laboratories were useful. Moreover, visiting lecturers got positive feedback from the audience and overall course content about information systems was interesting. Most of the respondents felt that there is no need for improvements. Few persons felt that distribution protection should be explained in more detailed.

2016 Kaiku feedback has similar responses to those at spring 2017. Responders felt that laboratories were useful and course content was interesting. Few of the answers mentioned that there could be more assignments.

2.3.2 External Enquiry

This part examines enquiry that was send to students who had taken the course distribution automation. There where 12 responders and they had taken the course during the spring 2017 or the spring 2016.

The most of the respondents had taken the course during last implementation. Persons felt that course content was still bright in mind. Responders remembered what SCADA system and DMS system are. They also had genuine understanding about AMR system.

The answers regarding the first laboratory suggested that participants had understood the assignments. Laboratory instructions were clear and there was enough guidance. The answers regarding the second laboratory included few comments stating that participants were not able to remember what they had done in the laboratory. However, most of the students felt that pre-laboratory questions were useful. Both laboratories were considered as safe although, according to the participants, laboratory environment should be cleaner.

Responders had left three answers to open word question. One responder wished that the laboratory would concentrate more on ICT structure of substations. Relay protection operation and wave forms were wished to be present better, too. Laboratory instructions were hoped to be more understandable.

3. DISTRIBUTION AUTOMATION

The importance of distribution automation has increased due to a growing interest in smart grids [3]. Distribution automation is used in network protection, controlling and monitoring. Automation enables one to accomplish these tasks remotely. The term distribution automation covers distribution automation system and distribution management.

A distribution automation system refers to technologies that enable one to coordinate, monitor and operate a distribution network from remote locations. These technologies include functionalities, network devices and communication systems. Figure 7 below illustrates distribution automation.

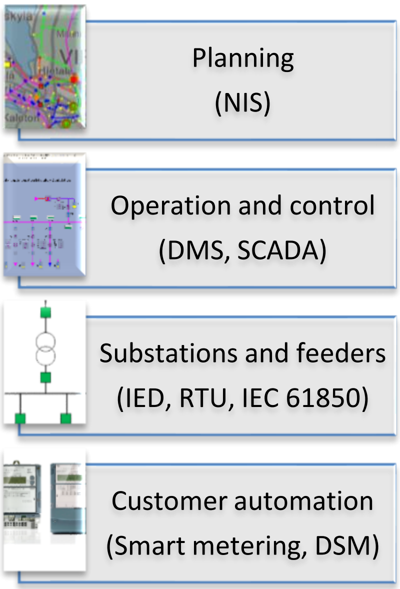

Figure 7. *Distribution automation [4, 5].*

Figure 7 illustrates the layers of distribution automation. Inside the boxes are examples of automation equipment used on each layer. The top layer is called planning, in which the Network Information System (NIS) is applied in a long term development of the distribution network [6]. The second level combines different Information Technologies (IT), such as DMS and SCADA, in network operation. The third level is distribution network level, which contains substations and feeders. In this thesis, the distribution network will be considered to include primary substations, feeders, secondary substations and customer connection points. On the bottom layer there is customer automation that includes smart metering, demand side management (DSM) and load control for example.

Figure 8 below shows how distribution automation is located in relation to the distribution network. The distribution network, substations, medium voltage and low voltage feeders, and SS are referred to as the primary process in Figure 8. On the distribution automation side are equipment that help in remote operation of the distribution network. Substations, feeders and customer level have IEDs, RTUs, customer automation and other substation automation such as tap changer. Distribution automation side also consists of remote communication, SCADA, metering system, DMS, customer information system (CIS) and other information systems such as metering data management system (MDMS). DMS has important role in the distribution automation system because it has access to various information systems to build overall view from the distribution network [6, 7].

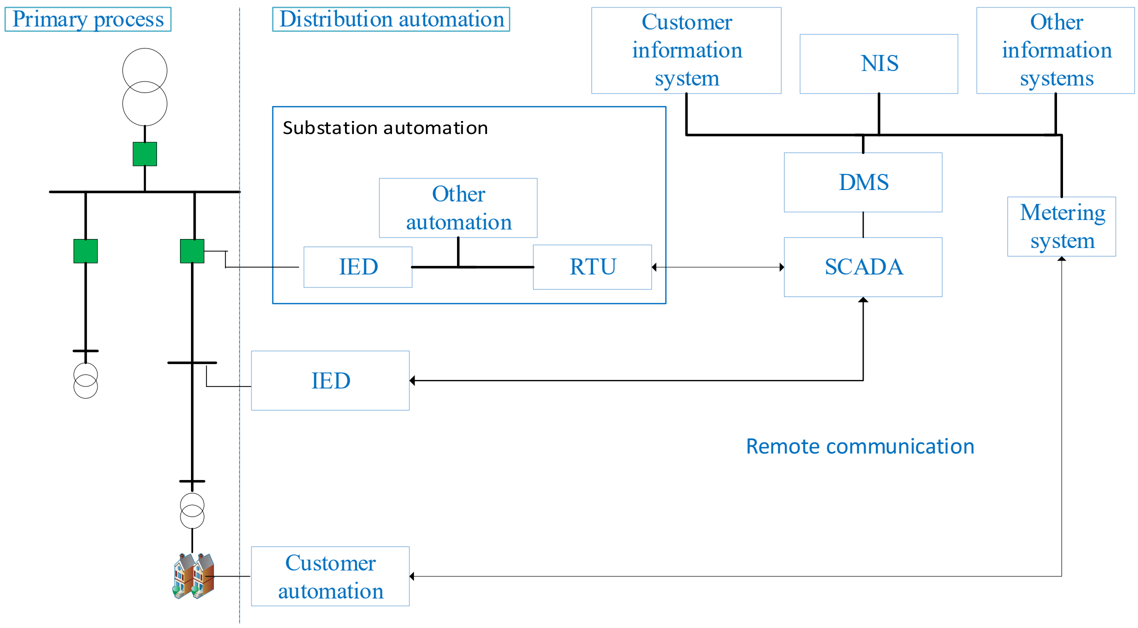

Figure 8. *Distribution automation functions [8].*

This chapter will focus on the three bottom layers of Figure 7 earlier above. The chapter introduces terms and functionalities of distribution automation, and communication protocols.

3.1 Intelligent electric devices

IED is the term used for multipurpose devices in the electricity distribution utilities. These devices are used for protection, control, metering, communication and fault recordings in the distribution network [4, 9]. In the distribution network protection, the term protection relay has often been used to describe device which is meant to protect a distribution network. The term relay is not enough to describe devices’ functionalities which protect distribution networks today.

The development towards IED began in the 1960s, when digital-based relaying was suggested to use in power system substation protection. In the beginning of digital relaying, the main focus of research was algorithms to detect faults from voltage and current wave forms [10]. Proposed algorithms were based on Fourier methods. Digital relays also introduced the possibility to provide multiple protection functionalities for one protective device. One protective device was now able to contain all the protection schemes that were needed in feeder protection for example [11]. Digital relays developed to numerical relays which are based on microprocessors. These microprocessor based devices introduced the possibility for more functionalities than just protection, as the microprocessor relays where able to transfer and receive controlling information [9].

After realizing that relays could be used for multiple purposes instead of just protection, manufacturers started to develop devices with multiple functionalities. The relays started to provide more than just protection functionalities. The term relay was not descriptive enough to define the devices anymore, thus the IED was born [9].

IEDs have multiple functionalities and software is an important part of these devices. The voltage and current measurement as well as the communication functionalities are among IEDs' basic properties. IEDs contain various protective functionalities [4]. The devices are located on the secondary side of an electric circuit and the primary values of a electric network are converted to secondary values with instrument transformers [11] or sensors. Recording makes it possible to investigate fault afterwards. IEDs are used in switch gear controlling, and they can be used in local and remote control.

The following subsections describes IEDs as protective devices, although IEDs' have also other functionalities, such as communication. The first subsection describes the protection scheme, which defines the protection principles of the distribution network. After introducing the protection principles, the fault diagnostic, overcurrent protection and earth fault protection are described each in their own subsections. At the end of the section, IED device REF615 and its functionalities are introduced.

3.1.1 Distribution network protection

The main principle of distribution network protection is to detect the abnormal state of the network. It is important to detect faults fast. Depending on the type of fault, faults can be harmful to network equipment, operation and network environment. In addition to operating fast, protection should only operate when faults occur, remove only the faulted part from network and be structured in hierarchical manner. Standards provide the minimum requirements but with extended features outages can be reduced to minimum [8].

An important aspect in distribution network protection is to recognize operation environment. One key factor is the network type. The network type can be cable or overhead line. In cable networks the faults are different than in overhead line network, which affects to the protection principles. For example auto-reclosing is not used in cable networks, but networks which include cable and overhead line uses auto-reclosing. [12-14]

Distribution network protection should fulfill certain aspects. Protection should cover the protective area in addition to being selective, sensitive, fast, simple and reliable. Other aspects are easy to use, testing and cost-effectiveness. Protection is selective when protective device operates to faults on its protection zone [11]. Sensitivity and fast operation minimize damages for network and environment. Protection should be possible to test on its location and cost-effective from investment costs.

In Finland SFS 6001 provides the requirements for protection. SFS 6001 is the standard that covers high-voltages electrical installations [15]. SFS 6001 combines the two international standards EN 61936-1 and EN 50522. SFS 6001 requires that the high voltage network protection must cover certain aspects. Protection must implement overcurrent and earth faults. The protection should also cover thermal effect, over and under voltage, and low frequency. The standard provides fault durations and allowed touch voltages for earth fault. Earth fault protection must have back-up protection, whereas for overcurrent back-up protection is optional. Distribution network companies need to fulfil the standard requirements in the network protection.

In distribution networks protective devices are typically located at the substations [8]. Line breakers alongside the medium voltage feeder are rare [12-14]. Today, automated fault indicators are added to the feeders in order to attain better information about fault current flow to estimate fault locations. Fault indicators are able to detect faults, but they are not capable of clearing fault as the protective relays [16].

Substations are key instrumental in electricity networks. At distribution network substations, high voltage is transferred to medium voltage and network is divided into feeders [8]. Figure 9 below presents the basic model of substation medium voltage side. The figure illustrates the primary transformer, two outgoing medium voltage feeders, one high voltage circuit breaker and three medium voltage circuit breakers. The circuit breakers are marked with green squares. Substations include also another switch gear instead of just circuit breakers, but other equipment are not presented in the figure. The substation medium voltage level is typically considered to have one input direction from primary transformer or transformers to medium voltage network [8]. When the amount of DG increases, medium voltage feeders can also serve as input feeders. When substation has several input feeders, it also affects to protection. In this thesis, distribution network substations are viewed as radially operated with one feeding direction.

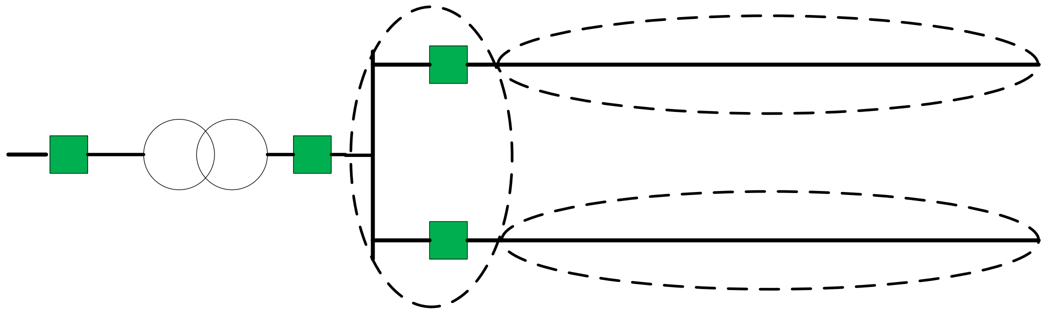

Figure 9. *Simplified substation structure.*

Figure 9 can be divided into different protection zones. In the figure the substation's protection zones are marked with dashed lines. The protection areas and principles depend on the network topology and the feeding directions. This section concentrates on busbar and feeder protection. The feeders are regarded as areas beginning from outgoing feeder current transformer until the end of line. The current transformers are located at beginning of feeders. Busbar protection area is between the primary transformer and outgoing feeders' current transformers [11].

DSOs' ideas about busbar and feeder protection varies depending on company. The busbar protection is also known as transformer protection. The busbar protection is thought to include overcurrent, earth fault, over voltage and under voltage protection functions, where over and under voltage is not always tripping. Feeder protection includes overcurrent protection, several earth fault protection functions and inrush detection in overcurrent. Another protection functions that DSOs mentioned were arc and conductor break protection. Selectivity is provided with constant-time-delay and blocking message. Blocking message implementation varies from hardwire connection to GOOSE message. The time delay is planned so that busbar protective device is not allowed to operate before feeder protective devices operate. Feeder earth fault back-up protection is possible to do with external back up protection relay, busbar protective device or manually by system operator. Overcurrent back-up protection is done with the busbar protective device or arc protection device. Auto-reclosing is used in networks which are overhead lines or combination of overhead line and cable. In cable networks, auto-reclosing is not used. Delayed reclosing is applied automatically or manually. The same protection settings are tend to use at different feeders in urban networks were network topology configuration may have a lot of different variations. This makes the network operation easier even though at some feeders protection could be more sensitive. [12-14]

3.1.2 Fault diagnostics

A disturbance recording is often the only way to find out a reason, why an IED protection has operated, if the protection has operated an unexpected way. In addition disturbance recordings can also be used to network condition management, customer service, electricity quality management [17] such as detecting harmonics or sub-harmonics. In customer service system operator can prove with disturbance recordings that there has been a normal fault in the system and customer is not rightful to refund in electricity distribution bill [12]. When planning the recording of events in distribution network there should be considered type of event to record, sampling frequency, limitations and errors, triggering, length of record, needed analog and binary channels [18].

In JE-Siirto, the disturbance recordings are seen as parts of outage management and network management. Outage management is a process to return the network from the emergency state to normal state and network management consists of network planning, customer service, real time operation and control, and other factors which are considered as DSOs' tasks [19]. In outage management JE-Siirto uses disturbance recordings during fault situations in order to understand the reason of a fault, because of SCADA is not capable to present as detailed fault measurements from primary process. In Elenia and TSV, disturbance recordings are studied more after the fault is cleared from the network to explain reasons for protection functions operations. [12-14]

The disturbance recorder can be used for recording transients, short and long term faults, and normal operation of the distribution network. The data from the recordings can be analyzed after faults, and then used for improving the network reliability [18].

In order to being able to record fault situations to the disturbance recordings, trigger settings are important. There are several triggers to choose from. Recording trigger option can be either duration or edge based. In duration based triggers, the purpose is to keep recording through the whole fault. Edge based triggers keep recording for fixed period of time. Triggering method affect to how well an event is recorded.

Figure 10 below illustrates an edge-based recording with a fixed length. Recording length consists of a pre-triggering and post-triggering time frame. Pre- and post-triggering divide the recording into two areas. The pre-triggering area records events and measurements before the triggering. Post-triggering area is the area after the triggering conditions are fulfilled. The post-triggering area orders the recording length.

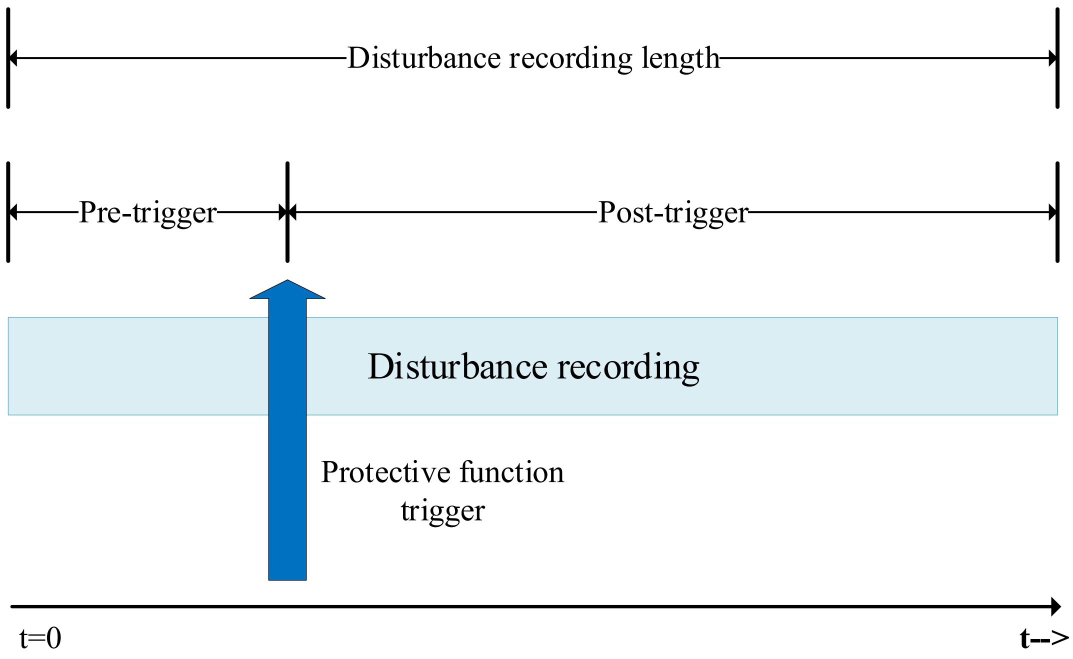

Figure 10. *Disturbance recording [18].*

Another method for record disturbance recording is durational triggering. In duration triggering, recording is divided into time intervals pre-trigger, during triggering and post-trigger. Recording length depends on during triggering time interval [18]. During triggering interval means the area between the triggering conditions are fulfilled and the triggering conditions are not fulfilled anymore.

IED fault diagnostic is typically collected to Common format for transient data exchange (COMTRADE). The COMTRADE standard part 24 describes format for information storage of transient waveform and event data in power systems [20]. The information is in a form that can be stored in physical medias.

3.1.3 Overcurrent protection

The purpose of overcurrent protection is to prevent damage to conductors and to isolate the faulted feeder from the network. Overcurrent is dangerous to network equipment and environment. The protective device should detect these faults fast [21]. Protection should detect faults, but not operate in normal load condition.

The overcurrent, which the protective device must detect, are overloading and short circuit faults. Overloading means a situation in which the load current exceeds the rated current of the conductor. Short circuit faults are phase-to-phase and three-phase faults [22]. The fault current root mean square value can be kilo amperes in short circuit faults. In overload situations the current is near the normal operation current, but safe operation limits are exceeded [8]. The overcurrent cause heating damage.

In overcurrent protection, the protection should operate fast for high fault current, detect the lowest fault current and notice overloading. In overcurrent protection configuration, the current limits are gotten from rated currents. Rated currents at the feeder are three-phase short circuit in the beginning of the feeder, two-phase short circuit at the end of the feeder, and maximum load current [8]. Rated currents at busbar are three-phase short circuit and maximum load current. Difficulties for setting the protection level arise, if the topology of the network changes [11]. DSOs have possibility to analyze fault currents with NIS and DMS. [12-14]

Overcurrent protection current is typically set in a way that it has different current protection stages. In the protective device, there can be from two to three different stages of overcurrent protection [12-14]. The stages are set for the purpose of attaining different levels of sensitivity and operation speed. One solution is to set one of the function's operation current in between of maximum load current and smallest rated short circuit current. [8]. A good operation effective current value, for high current protection function, is two kilo amperes root mean square value. Protection function with highest rated current can be set to operate without time delay, but in networks, which include one or several transformers with high rated power, inrush current must be considered [12].

Overcurrent protection fault currents can be calculated with formulas 1 and 2 presented below. Formula 1 is for calculating three-phase short circuit current. In formula 1, I_k is three-phase short circuit current, whereas U_{ph} equals phase voltage before fault. Z_{tot} stands for total impedance of the network before fault [8].

$$I_k = \frac{U_{ph}}{Z_{tot}} \tag{1}$$

Two-phase short circuit current is calculated with formula 2, where I_{k2} stands for two-phase fault current. I_k equals three-phase short circuit current.

$$I_{k2} = \frac{\sqrt{3}}{2} * I_k \tag{2}$$

Selectivity can be ensured with operation delay at the protection stages. Operation delay is used to prevent miss operation of protection stages and to ensure selective operation when different protection devices are involved. Operation delay can be either constant- or inverse-time-delay. Constant-time-delay is a common setting in the distribution networks in Finland. In inverse-time-delay operation delay for specific current values is gotten from inverse definite minimum time (IDMT) curve. In IDMS curve the operation time is dependent on current value [23].

In order to choosing operation delays, there are a few basic principles which are needed to consider. These principles are the operation time of protection device, operation time and arc time of the circuit breaker, and diversity in protection device operation time [11]. Also, operation delays depend on the network equipment current rating [12-14].

The hierarchical structure of the protection needs time delay to receive selectivity, because a protective device should operate to faults on its protection are in the first place. When protection is hierarchical, the upper levels of protection devices can also operate as back-up protection for lower level devices. A lower level protection device must have shorter operation delay than higher level protection, to ensure faster operation of lower level protection, to its protection zone faults. Although, at the same time this brings a side effect that the operation time for highest fault currents is the longest [11].

With fast overcurrent protection functions, such as instant operation functions, time delay is not a possible solution to achieve selectivity, because distribution network protection is hierarchical. Blocking is used, to reach selectivity, with high operation speeds. When blocking method is used, the protection device closest to the fault sends a blocking signal to the back-up protection device's fast protection function [11]. The blocking signal is sent only if fault is found on the protection area and blocking should not block back-up protection, so that in a case of circuit breaker fault, back-up protection does not operate. Traditional way to implement blocking functionality is hardwire connection between protection devices. IEC 61850 have brought possibility to send GOOSE blocking message via Ethernet data link layer, which is considered as faster way than hardwire connection [24].

3.1.4 Earth fault protection

In addition to being the most common fault type, earth faults are hazardous to the environment. In earth faults the fault currents are small, when compared to short circuit faults, and fault current is in between 5A and 100A in unearthed systems, which makes it difficult to detect the fault during earth faults [8]. Protection sensitivity may be a problem in earth fault protection. High resistance faults are especially difficult to detect because of small currents, which causes problems to protection sensitivity. [25].

The grounding method affects to the fault current flow [21]. In unearthed systems fault current flows through the network capacitances, because the network does not have connection to ground besides at fault location. During the earth fault, fault current flows to the ground through fault resistance in fault point [8]. Fault current flows back to the feeders through the capacitance between the line and earth. This subsection concentrates on unearthed system.

Fault current can be calculated with formula 3. In formula 3, ω means angular frequency, C_0 means total network phase capacitance between line and ground, R_f means fault resistance, and U_{ph} stands for phase voltage before fault. Fault current is the current that flows from the line to the ground, but is not detected by the protective device [11].

$$I_f = \frac{3\omega C_0}{\sqrt{1 + (3\omega R_f)^2}} * U_{ph} \tag{3}$$

In the distribution network, earth fault protection is not based on fault current measurement. Typical measured factors have been a residual voltage and a residual current from fundamental frequencies. The disadvantage of using the fundamental frequencies is the lack of sensitivity in high resistance faults [25]. Other possible measured factors are harmonic components of current and voltage, and transient currents [8].

A common solution for detecting earth fault is a residual current. Residual current is a part of the earth fault current, which flows back to the substation. Residual current is either calculated or measured from phasor currents. Residual current is measured with a three-phase current transformer that detects imbalances between phasor currents.

In an unearthed network, residual current can be calculated with formula 4. In formula 4, C_0 is total capacitance of a phase between line and ground, C_{0j} is the phase capacitance between line and ground of faulted feeder's and I_f is the fault current [11].

$$I_0 = \frac{C_0 - C_{0j}}{C_0} * I_f \tag{4}$$

Residual voltage is used with residual current in earth fault detection. Residual voltage is between the ground and the wye point of the substation primary transformer. Residual voltage can be calculated with formula 5, where U_{ph} is the phase voltage, C_0 is the capacitance between line and ground, and R_f is the fault resistance [8].

$$U_0 = \frac{U_{ph}}{\sqrt{1 + (3\omega C_0 R_F)^2}} \tag{5}$$

The requirements for earth fault protection come from touch potentials, which are provided by SFS 6001. The earth fault current flows through the grounding resistance. Together, the fault current and fault resistance causes an earthing voltage between the ground and the energized object [8]. The voltage, which is possible to touch by animal or person is called touch potential.

Formula 6 presents earthing voltage. In formula, U_E is earthing voltage, I_f is the fault current, and R_E is the grounding resistance.

$$U_E = I_f * R_E \tag{6}$$

Earthing voltage is harmful for the environment [8]. Figure 11 below presents a scenario in which a person touches a distribution transformer during earth fault.

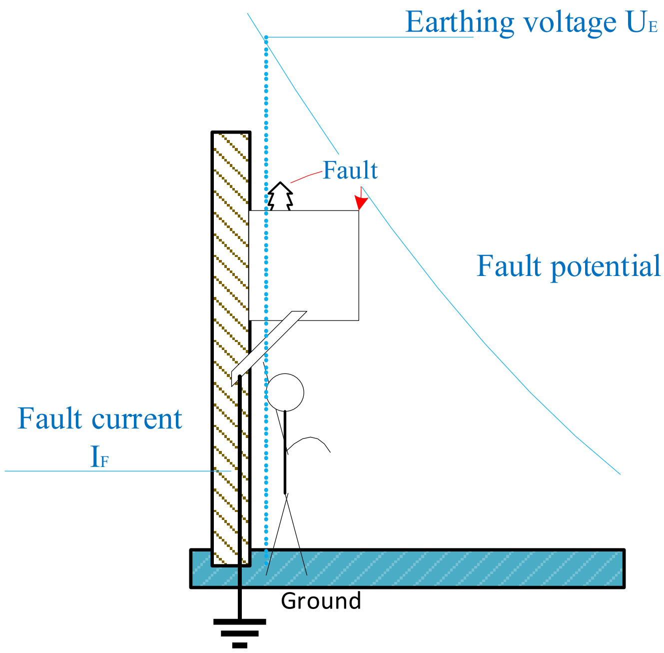

Figure 11. *Earth fault voltage [8, 15].*

In Figure 11, fault is located in a insulator of the transformer [8]. The blue curve represents potential during fault [15]. The person feels the touch voltage between the ground and the transformer, as the fault current flows through the person. In distribution transformers, the ground is often connected to the same ground as low voltage network neutral [8]. During earth faults, fault potential is transferred to low voltage network which causes dangerous potential in metallic covers of the electric appliances at low voltage network [15].

SFS 6001 restricts the approved earth fault voltages and fault durations [8]. SFS 6001 does not give restrictions or requirements for fault resistance along the high voltage line [12]. The approved earth voltage is calculated from touch voltages with formula 7 [15]. Secondary substation earthing requirements depend on the formula 7, when low voltage network is connected to the same ground as the distribution transformer.

$$U_E \leq k * U_{TP} \qquad (7)$$

In formula 7, U_E is earthing voltage, k is the multiplier for earthing conditions, and U_{Tp} is touch voltage. The value for k is typically two in Finland [8]. High k values are for badly conducting surfaces, such as rock or gravel. With higher k values there are conditions that need to be fulfilled. These conditions include external earthings. Higher k values allow higher earth potential during a fault.

In earth fault detection time delay is determined by SFS 6001. Time delay is depends on touch voltages which occur during faults [8]. The standard provides a logarithmic scale. Extra groundings can be used to improve grounding conditions, and in this way time-delay can be extended. Table 1 presents the accepted touch voltage durations in earth fault.

Table 1. *Time delays and touch voltages from standard SFS 6001 [8].*

Delay [s]	0,3	0,4	0,5	0,6	0,7	0,8	0,9	1
U_{TP}	390	280	215	160	132	120	110	110

By combining Table 1 with formulas 6 and 7, it is possible to determine operation delay for earth fault protection operation, and the requirements for transformer grounding conditions. With k value two, and 0,4s time delay, the highest earthing voltage that is allowed, is 2*280V = 560V calculated with formula 6. The required grounding resistance is then calculated with formula 7, 560V/50A = 11,2Ω, where the fault current was assumed to be 50A [8].

DSOs use different protection applications in earth fault protection. The most used protection functions are non-directional and directional earth fault protection, admittance based protection and transient earth fault protection. The settings of protective devices depend on the network and instrument transformers accuracy. Protection is done so that the same values are possible to use in different feeders or so that feeders have own protection settings which are suitable for particular feeder. Having same protection functions in the whole operated distribution network, makes network operation easier, whereas individual settings provide more sensitive protection. Busbar earth fault protection can be done with residual voltage with or without breaker operation. In some occasions earth fault protection at busbar is done remotely by the system operator. The length of the network may also change and the settings need to fulfil those needs. [12-14]

3.1.5 REF 615

REF615 is a part of ABB’s 615 series. The device is meant for feeder protection and control. It can also be used for busbar protection in radially operated networks [26]. REF615 includes different protection functionalities depending on the model. There are twelve different models, from which two have the full number of options [23].

REF615 provides a large number of protection functionalities for different purposes. Overcurrent, earth fault, and residual voltage protection functions for feeder protection are described in Table 2 below.

Table 2. *REF 615 protection functions [23].*

Fault type	**Description**	**ABBs IEC 61850 based name**
Overcur-rent	Three-phase non-directional overcurrent protection	PHxPTOC
Overcur-rent	Three-phase directional overcurrent pro-tection	DPHxPDOC
Earth fault	Non-directional earth-fault protection	EFxPTOC
Earth fault	Directional earth-fault protection	DEFxPDEF
Earth fault	Transient/intermittent earth-fault protec-tion	INTRPTEF
Earth fault	Harmonics-based earth-fault protection	HAEFPTOC
Earth fault	Wattmetric-based protection	WPWDE
Earth fault	Admittance-based earth fault protection	EFPADM
Earth fault	Multifrequency admittance-based protec-tion	MFADPSDE
Overvolt-age	Residual overvoltage protection	ROVPTOP

PHxPTOC and DPHxPDOC overcurrent protection functions are meant for one-, two- and three-phase overcurrent and short-circuit protection. PHxPTOC is not capable of detection fault current direction, whereas DPHxPDOC is [23]. PHxPTOC functions measure the current, and compare it to the set limit. In DPHxPDOC, the function current and voltage values are measured and compared to the set limits. The function also detects the phase angel between the current and the voltage. If the set limits are exceeded, the protection function starts the timer before tripping.

EFxPTOC and DEFxPDEF earth fault functions are meant for non-directional and directional earth fault protection. EFxPTOC is for non-directional protection, and it uses measured or calculated residual current. The function detects residual current, and if the set limit current is exceeded, the protection function starts the timer [23]. If the set limit is still exceeded after pre-defined operation delay, the protection function starts.

DEFxPDEF is for directional protection for feeders. The function calculates or uses measured residual current and voltages. Protection can be set to follow the residual current and voltage values, and the phase angle between these values. Another possibility is to measure the resistive and capacitive part from the current. In the directional earth-fault function settings the earthing of the distribution network has a major impact on protection settings. The grounding method impacts on the phase angle between the residual current and the residual voltage.

INTRPTEF is an earth-fault protection function for permanent and intermittent earth faults with directional protection ability. The function detects transients from the residual current and the residual voltage signals [23]. INTRPTEF has two different operation logics. Transient setting is meant for all kinds of earth faults in which intermittent setting is for faults in cable networks. In the transient logic, function follows the residual voltage value. Protection operates when the set residual voltage is exceeded longer than the set operation time, and reset delay time. Intermittent logic follows residual voltage value. The protection function operates, if set of transients exceed counters limit and time delay is exceeded.

EFPADM is a neutral admittance based earth fault protection function, which has a good sensitivity [23]. The protection function is based on neutral admittance which is calculated from the residual current and voltage values. The steady state admittance of the distribution network is the sum of capacitive and resistive parts of feeders. Steady state admittances are set on an admittance plane. Measured admittance is compared to the admittance plane. If the plane edge is exceeded, the protection operates depending on time delay [17]. The protection setting depends on the network earthing method.

MFADPSDE is multifrequency admittance protection function, which is based on multifrequency neutral admittance. When admittance protection is based on fundamental frequencies, the multifrequency admittance protection measures fundamental frequencies and harmonic components [17]. The protection is capable to detect earth faults and intermittent earth faults.

3.2 Distribution system operation

Distribution system operation has developed from the local manual control of power systems to centralized computer aided remote controlling of the systems [27]. The remote controlling and monitoring software SCADA and DMS have taken the control center. These systems provide automation controlling possibilities, as well as a general view of the process. The overall view is necessary for accomplishing a safe, economical and reliable system operation. This section describes power system control and monitoring.

The simplest way to operate a process is to meter measurable unit and control actuating device. When the number of processes and devices increase, process information is necessary to collect into one place to get an overall view of the system [27]. The good overall view enables reliable control of the system. In the power system, processes can be geographically widely spread. If all processes are presented in one control center, the whole system can be controlled from one place, and local control is not necessary.

Centralized control centers group information that can be used in monitoring and control of the process. Earlier in power system control, the systems overview was built on mimic boards where all processes were presented in schematic model. These mimic boards displayed systems signals, disconnectors, breakers, feeders and other factors from the system. If the system was modified, the mimic board had to be rebuilt. The mosaic structure of the mimic boards made it possible to reconstruct the system picture in the control center [27]. With large systems, system models became rather complex and idea of a good overall view disappeared. Computers introduced an alternative for complex mimic boards.

Computers entered to power system control rooms in the 1960s. In the beginning computers only controlled signals. When computers began to present parts of the system with visual display unit (VDU), mimic boards became less needed [27]. At the same time, the role of the control center operator changed. Computers started to analyze and provide information from the state of the network. The operator was able to use given information in the decision making process.

The development of system monitoring brought more possibilities for system operation. In distribution management, the key factors are quality, safety and economical operation [27]. Quality is often regarded as voltage and frequency quality, the power system has to be safe for its environment and the operation of the system needs to be economically reasonable.

Today, the distribution network operator controls and monitors network operations in real time. Operator operation also includes short-term planning and reporting. The distribution network operator uses DMS and SCADA systems to accomplish its tasks [19].

3.2.1 SCADA

SCADA is an automation control and monitoring system, that is used in electricity network operation and in industries, which have a significant use of automation. SCADA offers the possibility to control large automated systems locally or remotely in real time [19]. While understanding SCADA systems as a part of the distribution automation system, it is important to keep in mind that industrial processes are different from distribution network processes, because distribution network processes are geographically wide spread.

SCADA adds remote control and monitoring to distribution network operation. SCADA enables the operation and controlling of the distribution system remotely and locally [19]. Typically, SCADA communicates with remote terminal units (RTUs) in the distribution network. RTUs operate as data concentrators and communication units, and are located at substations and feeders in the distribution network. RTUs send information of primary process to the distribution network control center and vise versa. From RTUs, SCADA collects primary process information, which is further used in other IT systems.

The basic, modern SCADA system includes standard functionalities. Standard functionalities can be divided to the basic process functions, which are collecting data, monitoring collected data, event processing and controlling [19]. The process information of the standard functions is stored, and the process information can be accessed for later analysis. Standard functions are described next.

SCADA collects system data in different formats. The type of status, energy and measured values depend on the device and the instance. Status indications are typically sent as a single or double indication. The single indication has the stages on and off, whereas double indication has four stages: on, two middle positions and off [19]. Measured values can be digital or analog. Energy values are traditionally sent as a pulse counter values. The pulse counter values are sent as pulses in time intervals, and each pulse has a pre-defined value.

Processes have to be monitored, because the mere data collection functionality is not enough to tell the state of the system for the system operator. In the process monitoring, data values are collected, and new collected values can be compared with the previous data values. Limits can be set for monitored values, and exceeding a limit generates an event that informs the system operator about exceeding of a limit in the process. SCADA can also follow trends and set alarms, if operation is not satisfactory [19]. For example, SCADA could allow 7% change in the voltage measurement in a minute.

Processes can be controlled by the system operator or the automated functions. Controlling functions can be divided into four categories. These categories are individual device control, control messages to regulating equipment, sequential control and automatic control [19]. Individual control means applying control action to an individual device. The control message to regulating equipment refers to a message sent to a device, which starts an operation sequence that may include controlling of other devices. The sequential control means the completing of an automatically created list of commands by the operator. The automated control is the only fully automated type of controlling. The automated control is a set of pre-defined acts that begin with particular event triggering.

The process data is collected and stored in SCADA. In real time monitoring, old primary process values are updated with new values. Historical data can be used to serve data analysis [19]. Historical data analysis can be used in many functions, such as system load planning, performance audition and post-fault analysis.

Besides SCADA functions an important aspect of the SCADA system is its performance. Communication speed is an important factor in SCADA system performance. In early SCADAs the transfer speed was critical and the protocols were designed in a way in which every bit counted [19]. Today, the bandwidth is still a critical factor, but new technologies have made it possible to poll the process data more frequently, which enable to monitor the process closer to real time.

In communication, polling means scanning of a system. In SCADA system, data polling has two main types, which are cyclic and report-by-exception [19]. In cyclic data polling, measures and indications are scanned in different cycles. Important data points are scanned more often than less important. In report-by-exception polling, SCADA server polls the point cyclic, but the point answers with data, if exception level is exceeded. Polling type affects to response times in SCADA system. With cyclic data polling response times are constant and communication channels usage can be optimized by polling important data points more frequently than less important. And also, during disturbances the cyclic data pulling keeps constant, whereas report-by-exception data polling provides fast response times.

Restrictions for data polling frequency comes from bandwidth, which gives limits for how close to real time the system can be monitored. With help of priority the problems with bandwidth can be left out. The priority is design in a way that point with highest priority is pulled at first and the second most important point after the first. There can be several priority layers in the system. This kind of priority order provides good response time for essential information.

3.2.2 Distribution management system

DMS is a computer system, which presents the whole view of the distribution network for network operator. DMS combines information from various information systems. With information from those systems, DMS provide functions and applications to efficient network operation [8].

The network operator's operations can be divided into four main areas: topology supervision, restoration, scheduled outage planning and reconfiguration [28]. Supervision involves topology supervision from which basic tasks are switching state and network configuration monitoring. The restoration is fault management, which consists pre- and post-fault operations. The outage planning includes switching planning, customer service, outage reporting and executing the scheduled plan. Reconfiguration means reconfiguration of the distribution network, in which the network is configured to more optimal state or from non-accepted state to accepted state.

DMS system provides applications to reliable network operation for network operation. Figure 12 below presents a DMS system structure [29].

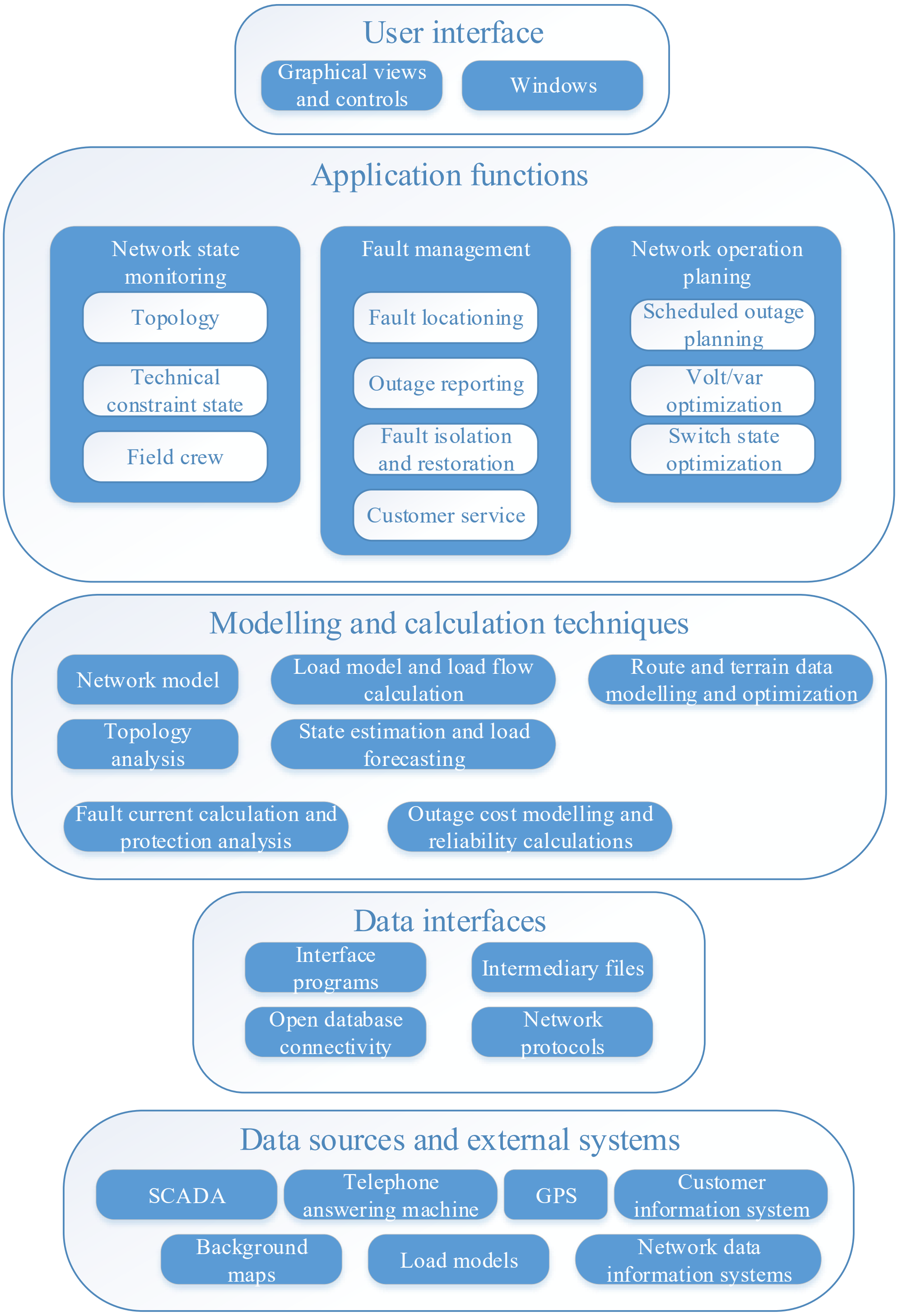

Figure 12. *DMS structure [29].*

Figure 12 contains five layers. Layers present the parts that build a functional DMS system. Layers are described next.

In Figure 12, the top layer is user interface (UI). UI presents the system on control center monitors and is the interface between the system and the operator. UI is important part of DMS from the system operator point of view, because UI presents the distribution network topology, DMS applications, alarms and other notifications for the system operator [30]. Figure 13 below presents a snap shot from DMS UI in which is presented network state and topology, network component symbols, measurements and geographical names.

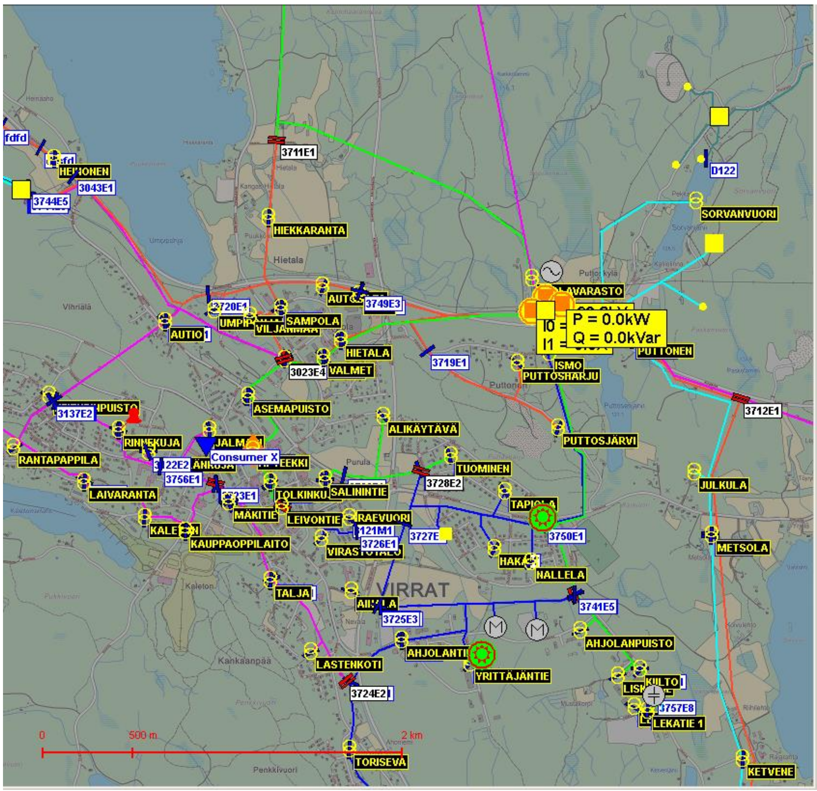

__Figure 13.__ Distribution network presented in ABB DMS.

Application layer functions provide support for the network operator in DMS. Application layer functions are basic functions, which are applied in network operation. Functions are classified into three groups: network state monitoring, fault management and network operation planning [29]. State monitoring includes functions that provide information for building picture from the network. Fault management group contains applications which help in fault situations and informing customers. Network operation planning include functions to maintain the network and optimizing the network operation to minimizing total costs.

Modelling and calculation layer offer information for the operator's actions. DMS includes several modelling and computation technique functions. These functions are network modelling, real-time stage analysis, load model and load flow calculations, state estimation and load forecasting, fault analysis, protection operation analysis, reliability calculations, and blackout costs. These functions are at the back ground of working applications [30].

Data interface layer provides protocols and programs for DMS. Provided protocols and programs are for accessing data sources of various computer systems. Protocols, such as OPC, are used for accessing the information of other computer systems. In some occasions accessing other systems data, an interoperability software is needed in between the data source and DMS [29]. Intermediary files also co-operate in between the data source and DMS system. Intermediary means file which is created, updated and used as data source by the DMS or other programs.

On the bottom layer are data sources and external systems. This layer includes all programs, devices and databases, which DMS uses. Data sources are accessed with data interface layer functions [29]. The benefit of accessing data from various programs, and not building one program with all functionalities, splits the system, and makes the system better scalable.

The role of DMS and SCADA depends on DSO. In interviewed distribution companies, the role of these systems varies. A one way of using DMS and SCADA, is a way were all network components are controlled from SCADA, and DMS's role is to show the current network topology and state. The other way is to use both systems in the network configuration management. In this type of using SCADA and DMS systems, the network devices with remote operation capability are operated from SCADA, and devices that are operated manually the state of a network equipment is changed from DMS. [12-14]

3.2.3 ABB MicroSCADA Pro

MicroSCADA Pro is ABB's product family and it includes SYS600, DMS600 and SYS600C products [31]. MicroSCADA Pro SYS 600 is SCADA system, which works on Windows platform. DMS600 is DMS system, which provides network management functionalities. SYS600C is industrial computer with SCADA installed. This chapter describes ABB MicroSCADA Pro SYS600 and DMS600.

SYS600 is automation product to substation automation and network control. SYS600 architecture is presented in Figure 14 below. The hearth of SYS600 is a system server. The system server manages all the functionalities provided by SYS600 [32]. In each system server, there is a one base system that does central data processing. Base system consists of one or several system applications. The base system consists of applications, system services and SCIL engine. One base system can be installed on one computer or distributed into several computers.

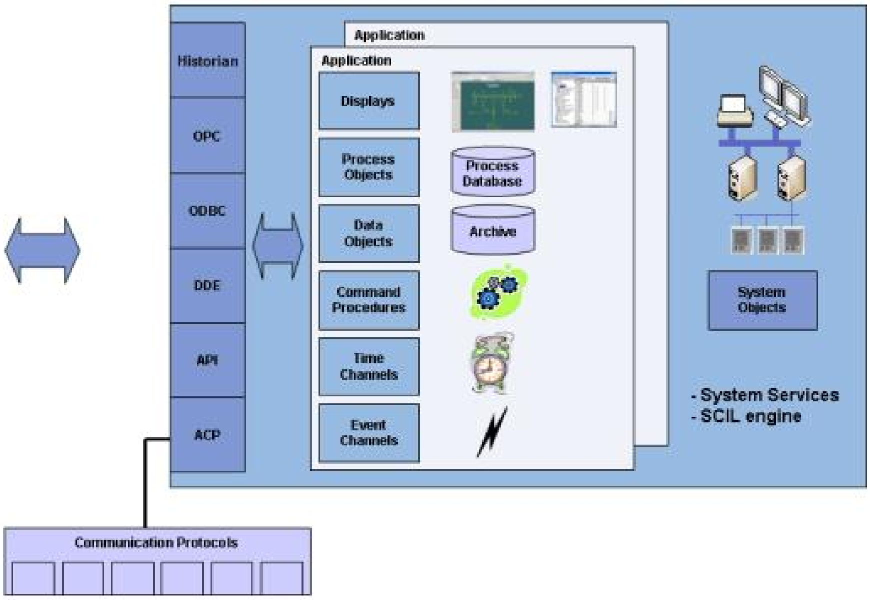

Figure 14. *SYS600 architecture [32].*

SYS600 Application provides functions of SYS600. SYS600 functions are added to application with application objects. There are various application objects which are process object, event handling object, scales, data object, time channel, event channel, logging profile, event object, free type object and variable object [32]. Application objects' state is defined with attributes. Attributes contain dynamic and static data of the object.

In communication, SYS600 supports several protocols. All modern SCADA protocols are supported including IEC 104 and DNP3 [32]. Other supported protocols are IEC 61850, OPC, IEC 61107, Modbus, IEC 101, IEC 103 and LonWork.

The DMS600 has two main programs. DMS600 Network Editor and DMS600 Workstation. Both programs have individual UI [31]. DMS600 Workstation is for network operators and provides DMS functions. DMS600 uses SYS600 to present distribution management view [33]. In DMS600, DMS and SCADA functionalities are integrated. This make it possible to control and supervise network topology from same view. Network Editor is for creating and editing the distribution network.

DMS600 program contains application functions depending on license. Available application functions are presented in Figure 15 below.

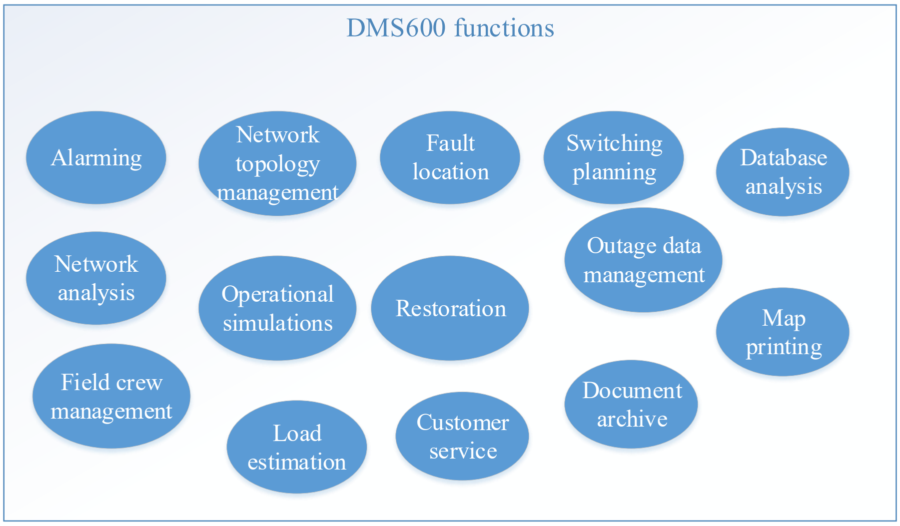

Figure 15. *MicroSCADA DMS600 functions [34].*

For data interfaces DMS600 provides several protocols, programs, database and intermediary files. For DMS and SCADA interface OPC Data Access or SCIL API is used [34]. OPC interface make it possible to integrate different vendor's SCADA to DMS600. Synchronization between SCADA and DMS is done through OPC Data Access interface. AMI configurations are done with configuration file. Connection to relational database is done with Open Database Connectivity (ODBC) and Data Source Name (DSN) definitions.

3.3 Smart metering

Today, the electricity metering infrastructure can be seen as extension of SCADA. Metering systems can be integrated as a part of distribution network operation in low voltage network fault indication, location and isolation for example [35]. This chapter reveals customer side metering.

JE-Siirto, Elenia and TSV thought that low voltage automation has important role in distribution operation and management. All of the three DSOs were thinking that smart metering has important role or would have in customer service today. Customers interruptions are easier to solve with help of AMI information. Smart meters offer information about customers fault and predefined alarms make fault solving faster. From three companies only TSV had no possibility to do remote requests to smart meters from control center. In Elenia smart meters' information is also used in medium voltage fault management. [12-14]

Energy metering has been used since the 1870s. The first metering systems were introduced during the 1990s. Today, electricity meters provide same functionalities as energy meters in the 1870s, but metering systems provide functionalities that can be seen as expansion of SCADA. Hourly metering became mandatory for DSOs in Finland in end of the year 2013. In the 2013 DSOs were required to install meters with hourly energy measurement to at least 80% of customers [36].

Electricity metering systems are know as Automatic Meter Reading (AMR) and Advanced Metering Infrastructure (AMI) technology. AMR metering brought remote meter reading to electricity metering and reduced the costs that meter reading brought earlier. AMI system is seen as next step from AMR system, by utilizing two-way communication for operator. In AMI system operator has possibility to send commands for meter. For customer, two-way communication brings better possibilities to affect one's energy bill by energy usage and tariffs [7]. AMI system structure is described next.

AMI technology is divides into four parts. These parts are smart meter, metering data management system (MDMS) and communication network. Smart meter is customer level metering device with communication and metering properties [37]. Smart meter has ability to send data and receive commands, which are transferred trough communication network. Communication network provides two-way communication for the AMI system, in which data concentrators present the key role as links between smart meters and head-end system. Data concentrators are communication units, which collect data from smart meters and forward the data to head-end system. Head-end system processes the data and forwards information to MDMS, or sends system operator commands to data concentrators. MDMS is information system, which manages, processes and stores metering data [7]. This section uses AMI system naming from metering infrastructure.

AMI system is for LV network management. The system structure can be divided into four layers. These layers are infrastructure, basic functions, reporting features and applied AMI [38]. Infrastructure level contains metering devices, MDMS, data concentrators and communication network. Basic AMI system functionalities are customer billing, load management, energy settlement and balance settlement. Reporting layer functionalities are energy usage information, interruption reports and energy saving. Applied AMI provide possibilities to expanded use of metering data. Examples from applied AMI are network management, fault locating, power quality monitoring and customer service. Applied features make possible to use distribution network more feasible way [35].

Typical AMI system topology is centralized system. Other AMI system topologies are distributed and fully distributed systems. Centralized system is presented in Figure 16 below. In centralized architecture, measuring information is collected from smart meters to data concentrators that are access points to smart meters [39]. Data concentrators forward smart meter data through communication channel to centralized MDMS. From MDMS distribution management system pulls AMI data.

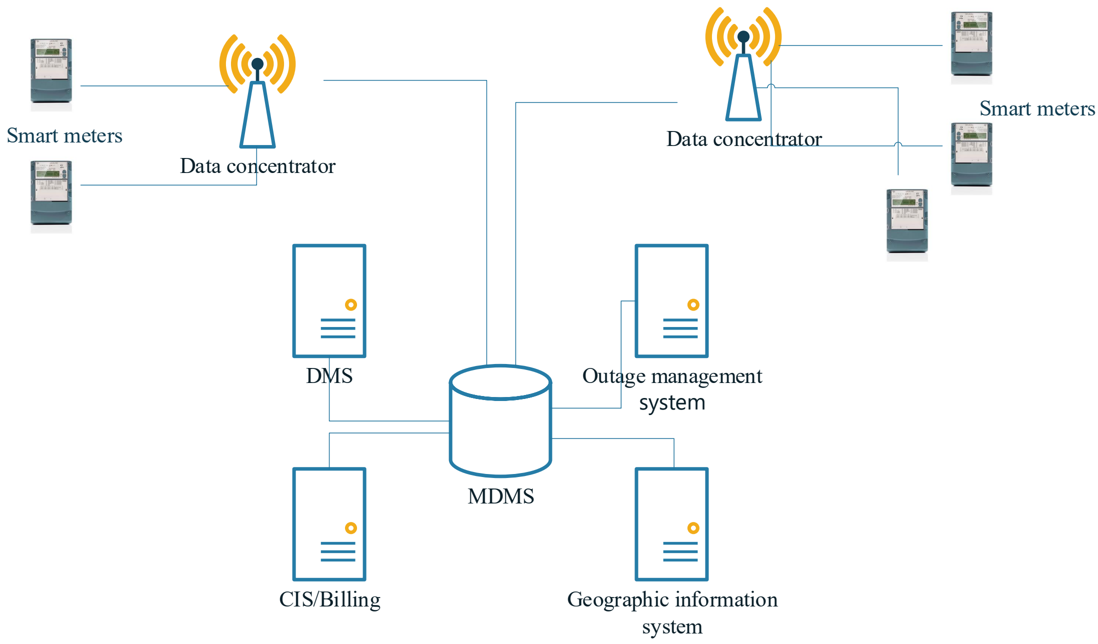

Figure 16. *AMI system with centralized MDMS [40, 41].*

In a centralized architecture the MDMS is located in a single server. The single server makes it easy to do requests to MDMS, but it is poorly scalable. Scalability issues occur with large metering systems in which the amount of data increases [39]. Large amount of the transferred data may cause bottle necks in communication as in data processing, which increase time delay in the system. Problems with bottle necks increase when AMI data is needed in real time, such as in fault management. Also, communication resources are lost when transferring all data to MDMS, because information travels long distances, but information is not necessary needed [40].

In decentralized topology, MDMS is distributed into local MDMS servers. Local MDMS collects data, processes information and stores data from concentrators. Central MDMS collects the data from local storages when the data is needed. Decentralized topology is presented in Figure 17 below.

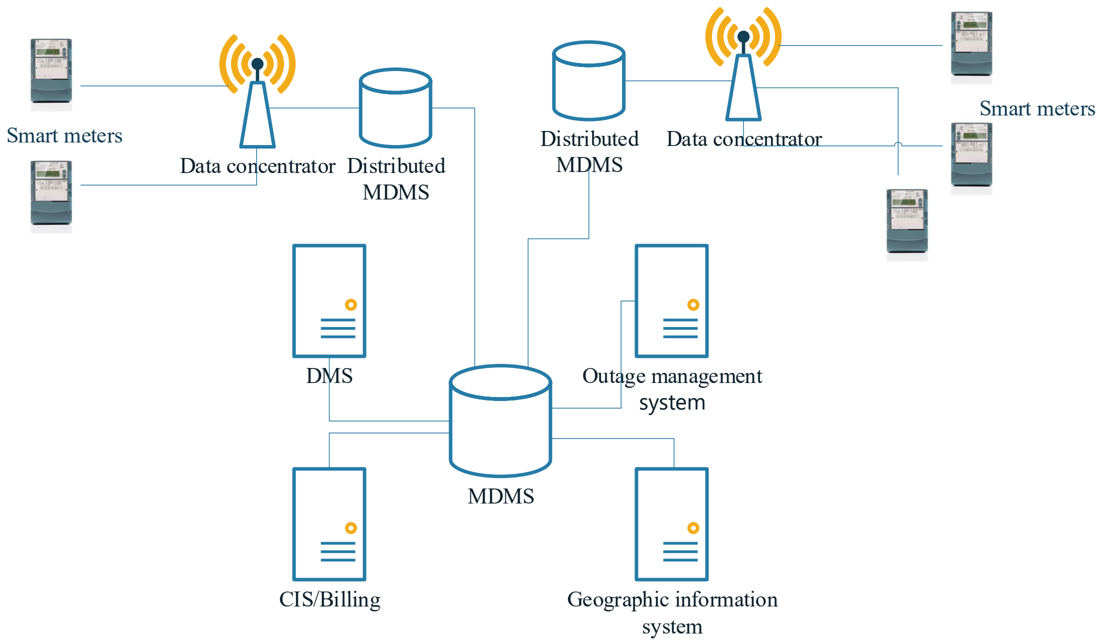

Figure 17. *Distributed AMI system [40, 41].*

In distributed architecture as in Figure 17, MDMS servers collect data from specific regions. In this architecture communication bottle necks are avoided, because data requests can be send to specific regions, which decreases amount of sent data [40]. Negative side is time delay which is result from pulling the data from decentralized servers. If decentralized MDMS system do data processing too, central MDMS saves time in processing time.

In addition to centralized and distributed architectures, there is also fully distributed architecture. In fully distributed architecture, local MDMS servers handle the most of the occurred situations locally. Operations of distributed servers are only reported to central station [40]. The benefit of fully distributed system is reduced costs in communication.

In communication smart meters use DLMS/COSEM protocol. Before DLMS/COSEM the field of low voltage automation was suffering from the amount of protocols when every vendor had their own protocol for communication [42]. DLMS/COSEM protocol is described later.

3.4 Communication protocols and standards

Protocols and standards act important role in distribution network communication. This chapter presents few fundamental standards which are used in distribution automation. IEC 61850 is communication standard, which defines communication protocols. IEC 60870-5-104 (IEC 104) is protocol for communication from distribution control center to substations and to other remote operated automation. Section also presents OPC and DLMS/COSEM standards.

To understand standards and protocols, this section describes object-oriented design and OSI model in the beginning. Information models of protocols and standards, which are described in this section, are based on object-oriented design. Communication architecture of protocols can be described with help of OSI model which is standardized network architecture model.

3.4.1 Object-oriented design

Object-oriented design is widely used in programming. Information models of the protocols and standards, which are described in this section, use object-oriented design in data models. To understanding standards' and protocols' information models better, this subsection revels the key terms.

In object-oriented design it is important to understand the terms class and object. Class is the instance, which defines the attributes and methods [43]. Methods present functionality of the class and are interfaces to access attributes of the class. Class creates logical structure for the object and standardized way to access the data from the object. In other words, class is a way to capsulate information into logical form. Object or objects are created from class. Objects that are created from the same class have same methods and attributes, but attribute values may be different. Different attribute values create different states for objects. Figure 18 below presents class from which two objects are created. Both objects have the methods getBookTitle, setBookTitle and getIdentity, which are implemented by the class. Objects attributes bookTitle and identity are accessed with methods.

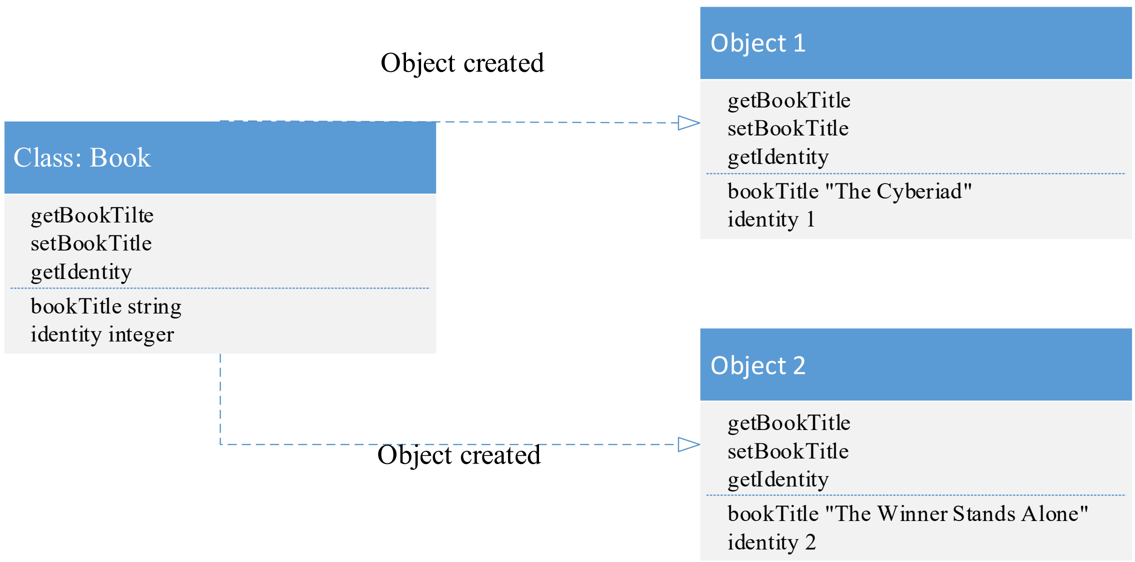

***Figure 18.** Objects created from the class Book.*

Because several objects can be created from one class, objects need a way to identify them from each others. From Figure 18 it is easy to see which object is object 1 and which is object 2. In practice objects need a simple way to separate them from each others. For separation object have identity. In Figure 18 identity is as simple as identity attribute.

In object-oriented design, class's features can be extended or modified with inheritance. Inheritance is a method, where class can be part of hierarchical structure of classes, where the class inherits the parent class or parent classes. In Figure 18 class Book could have connection to ActionBook subclass that would have features of book, but also define more specific attributes and methods, which are typical for action book. In this way classes separate things to logical modules and class defines particular functions for particular things. Inheritance bring possibility to polymorphism. Polymorphism mean that at place of an object can be used a sub-object of the object.

3.4.2 OSI Model

OSI model is de facto model to present communication protocols architectures. The model presents reference model, which has seven layers, for creating communication between two nodes.

OSI reference model development started in the 1977 by American National Standard Institute (ANSI). The final model was produced by ISO and the International Telecommunication Union – Telecommunication Standardization Sector (ITU-T). Communication protocols' architectural design refer often to OSI model. OSI model is presented in Figure 19 below. In the figure OSI model layers are presented on the right side and next to OSI model are examples from roles of layers.

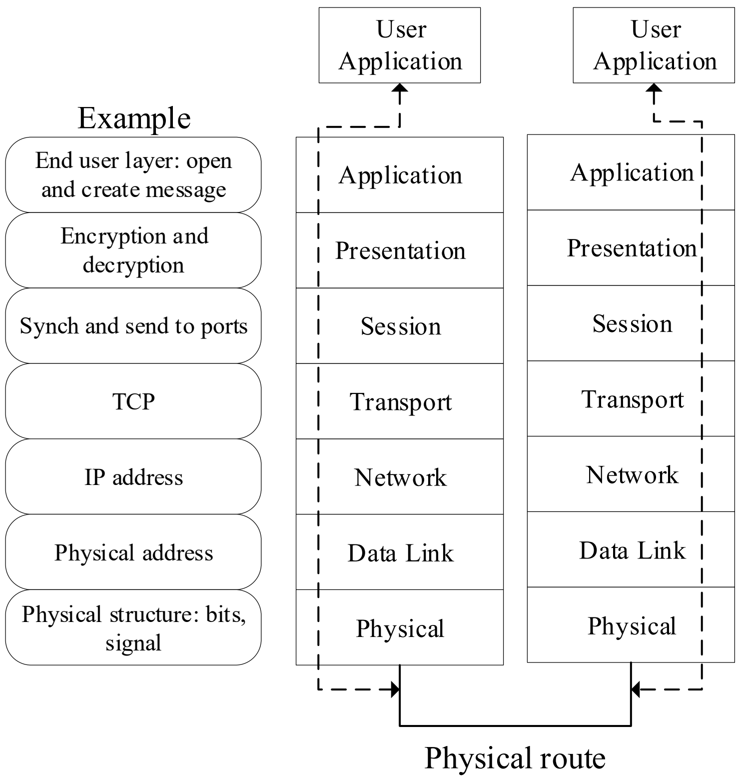

Figure 19. *OSI model architecture and explanation [44, 45].*

OSI model is divided into seven layers. Each layer has specific function and a protocol to implement this functionality [44]. Together protocols provide communication gateway for application process that operate on top of OSI model stack. Layers are numbered from 1 to 7 from which physical layer is layer number 1. Layers are described next.

The first layer is physical layer. The layer is in response to define relationship between device and a physical route. The layer provides interconnection to the physical route.

Data link layer is layer number two, and is in response to pack the information and transfer it to the next node. The layer detects and repairs physical layer errors.

Layer number three is network layer. Network layer transfers data sequences from sender to receiver over a network. The layer also provides possibility to routing where the network layer acts as a connection point between the original sender and the final destination of a message.

The fourth layer is transport layer that guards the message transfer from sender to the destination. The layer takes care of transferring the message. Transport layer optimizes the usage of the communication with minimum costs.

Session layer is layer number five, and it controls sender's connections to different receivers. The layer manages connection between presentation layers by establishing and closing connections. Session layer also controls the data exchange, limits the amount of the data and synchronize messages between the sender and receiver.

The sixth layer is presentation layer. Presentation layer provides services for application layer to form exchanged data to an understandable format. The services, which presentation layer provides, are controlling structured data, managing data exchange and displaying data structures.

Application layer is the top layer and layer number seven. The layer provides syntax to application processes that the message sender and receiver are able to communicate with each other. Application layer forms the application process data into a form that is common for the sender and destination.

3.4.3 IEC 61850

IEC 61850 standard is originally made for communication in substations to remove interoperability issues between various vendors appliances in the one system. The standard itself describes data model and communication framework.

IEC 61850 the first edition was published in the 2004. It was introduced as a communication standard for distribution automation. The second edition was introduced in the

2011. The key driver for the second edition was interoperability difficulties between different vendors implementations from the standard [46]. Interoperability issues were collected to www.tissues.iec61850.com website and modified to the second edition. Due to modifications, the first and the second edition have technical differences that might cause trouble in backward compatibility. Backward compatibility issues may arise in object references, flexible naming, schema version 2.0, new logical node and new common data classes.

Figure 20 below presents the ten main parts from the standard IEC 61850. These parts were introduced in the first edition of the standard.

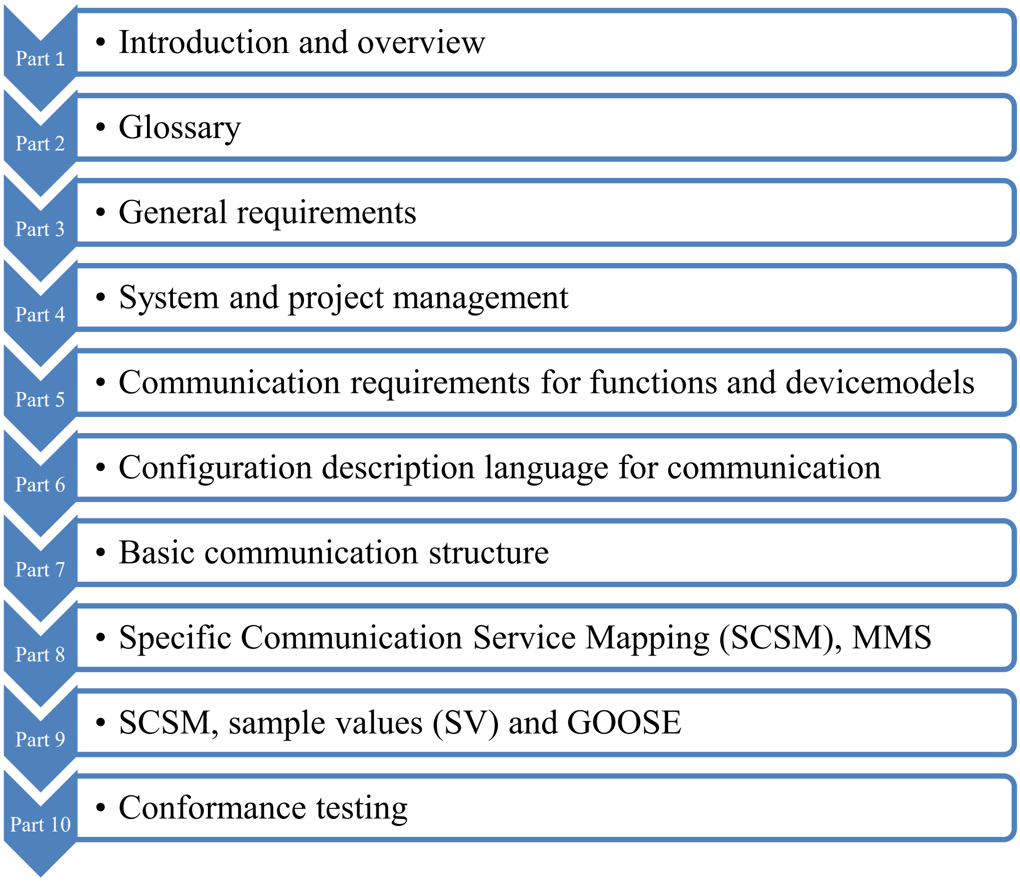

Figure 20. *IEC 61850 major parts overview [47].*

IEC 61850 has 10 major parts. 61850-1 presents overview to standard. 61850-2 provides terms' descriptions, which are used in the standard. 61850-3 defines general requirements about design, construction and environment of substation automation. 61850-4 describes system project management aspects, such as engineering requirements. 61850-5 describes communication requirements for functions and device models. 61850-6 covers system configuration model. Parts 61850-7, -8 and -9 cover information model and detailed communication methods [48]. In addition to the major parts, IEC 61850 also contains parts for mapping the standard on other protocols, and technical reports. Figure 21 below show how parts seven, eight and nine are positioned in OSI model.

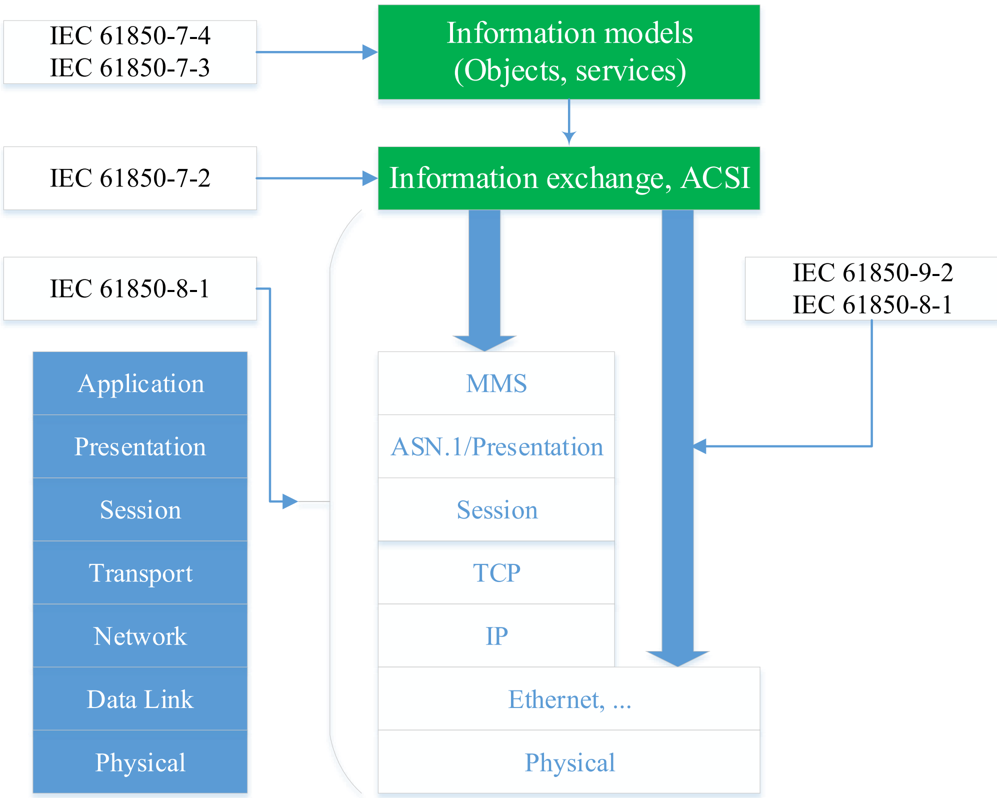

Figure 21. *IEC 61850 parts positioning in OSI architecture [48].*

Figure 21 show OSI model and IEC 61850 parts. Parts 7-4 and 7-3 introduce information model. Part 7-2 presents information exchange between client and server. Parts 8-1 and 9-2 implemented how specific IEC 61850 protocols are mapped on OSI model [49]. 9-2 part presents mapping of sampled values whereas part 8-1 proposes mapping of MMS and GOOSE. The difference between MMS and GOOSE is that MMS is mapped on application layer whereas GOOSE is mapped on Ethernet frame which is located on data link layer in OSI model [50]. In addition to GOOSE message, sample value is also mapped straight on data link layer to receive the shortest processing time and the fastest speed for sent data.

IEC 61850 information model is based on object-oriented design and the information model encapsulates data and methods into modules [49]. The information model is located on top of OSI model application layer as can be seen earlier in Figure 21. Information model's logical structure is presented in Figure 22 below.

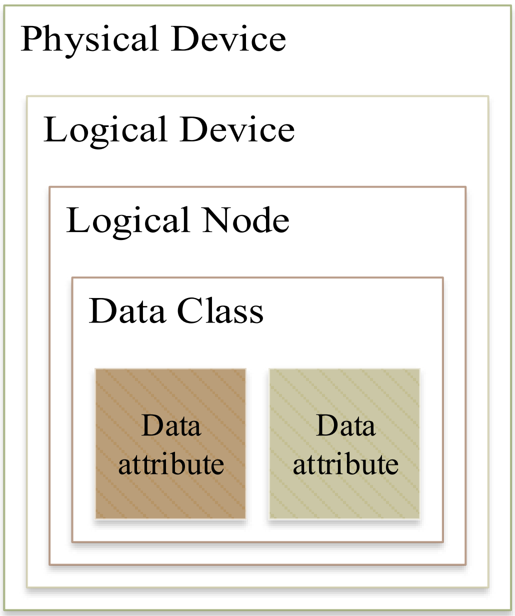

Figure 22. *Information model in IEC 61850-7-X [49].*

IEC 61850 information model is a stack of objects. On the first layer is physical device, like IED [50]. IEDs functionalities (protection, automation and etc.) are divided into logical devices (LDs). The standard does not specify any LDs. LD encapsulate logical nodes (LNs) that are standardized service blocks, which are defined in the IEC 61850 part 7-4. LN includes data classes that offer interface to access data attributes. Data attributes include the information that presents the state of LN. IEC 61850 information and information exchange models are abstract, which means that there is no specific implementation for these models.

An example from IEC 61850 information model is presented in Figure 23 below. The figure presents IEC 61850 information model from REF615. The IEC 61850 physical device is REF615 in the presented information model. REF615 includes several LDs from which CTRL is chosen [50]. CTRL object includes control equipment that are listed in LN column. Each LN has several data objects (DOs) which refers to data class earlier in Figure 22. DA column includes data attributes that the DO owns. FC column defines functional constrains, which defines purpose of data attributes, and services that data attribute provide. In Figure 23 the field Data set entities contains an IEC 61850 object from which CTRL.CBXCBR1.Pos.stVal(ST) is colored with blue. The object means line switch positions state.

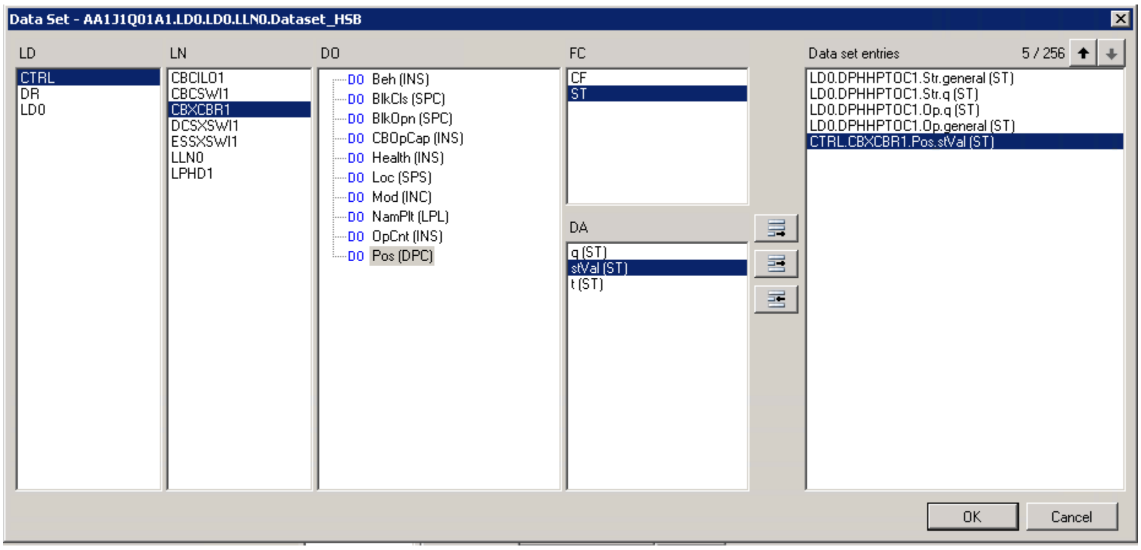

Figure 23. *IEC 61850 information model of REF615 from PCM tool.*

3.4.4 IEC 60870-5-104

IEC 60870-5-104 (IEC 104) is part of IEC 60870 standard that presents communication standard for remote control and monitoring in the field of power system automation. IEC 60870-5 part describes transmission protocols for communication between two systems. IEC 104 is companion standard, which extends the definitions of the main parts of IEC 60870 [51]. This chapter describes the standard's history, information model and communication.

IEC 104 is developed from IEC 60870-5-101 (IEC 101). IEC 101 was published in the 1995, and it was developed for telecontrol and serial communication. Due to low bandwidth of IEC 101 and increased need for better information flow, IEC 104 was developed and published in the year 2000. IEC 104 describes the similar data structure and functionalities as IEC 101 with minor changes [51]. The most important benefit that IEC 104 brought to remote control and operation of the power system automation, when comparing to IEC 101, was internet protocol TCP/IP.

IEC 104 protocol stack implements the most of OSI model layers. The OSI model architecture of IEC 104 and 101 is presented in Figure 24 below. The application layer of IEC 104 and 101 maps the application data into Application Service Data Units (ASDUs) that contain the information elements components that transfer the fundamental information under the protocols. On transport, network, data link and physical layers, IEC 104 provides TCP/IP, while IEC 101 implements only data link layer and physical layer for serial communication.

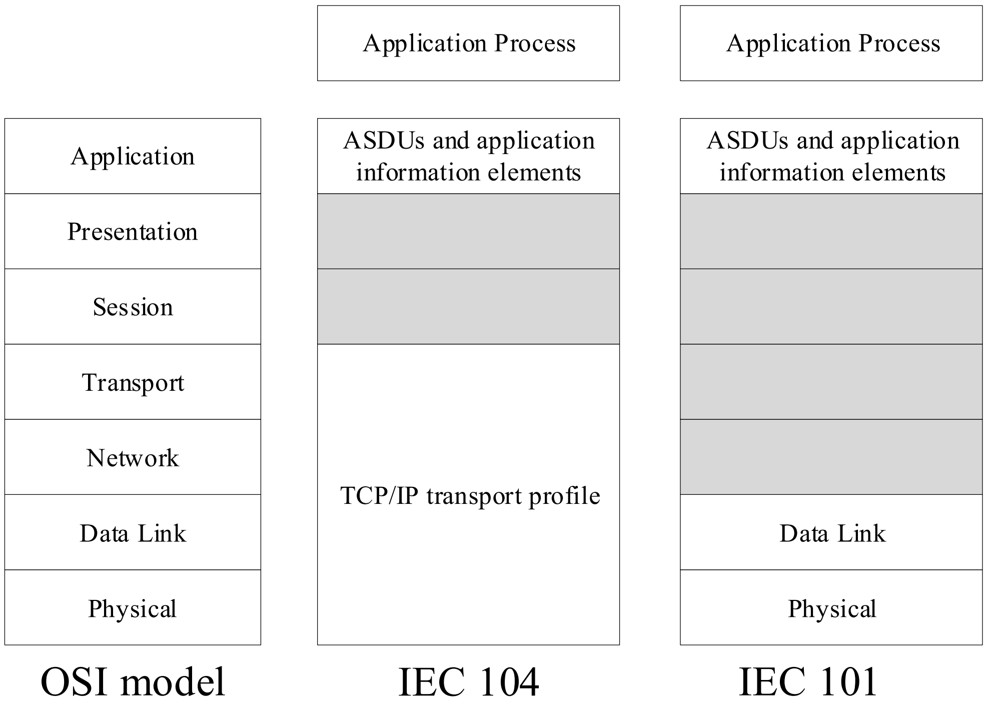

Figure 24. *IEC 104 compared to OSI model [51].*

ASDU is the information model in IEC 104, which contains the process data and identifier. In ASDU the process data is stored into information objects' information elements. Figure 25 below presents two different ASDU structures for IEC 104 and 101. ASDU on left side has several information objects, whereas ASDU on right side has several information elements.

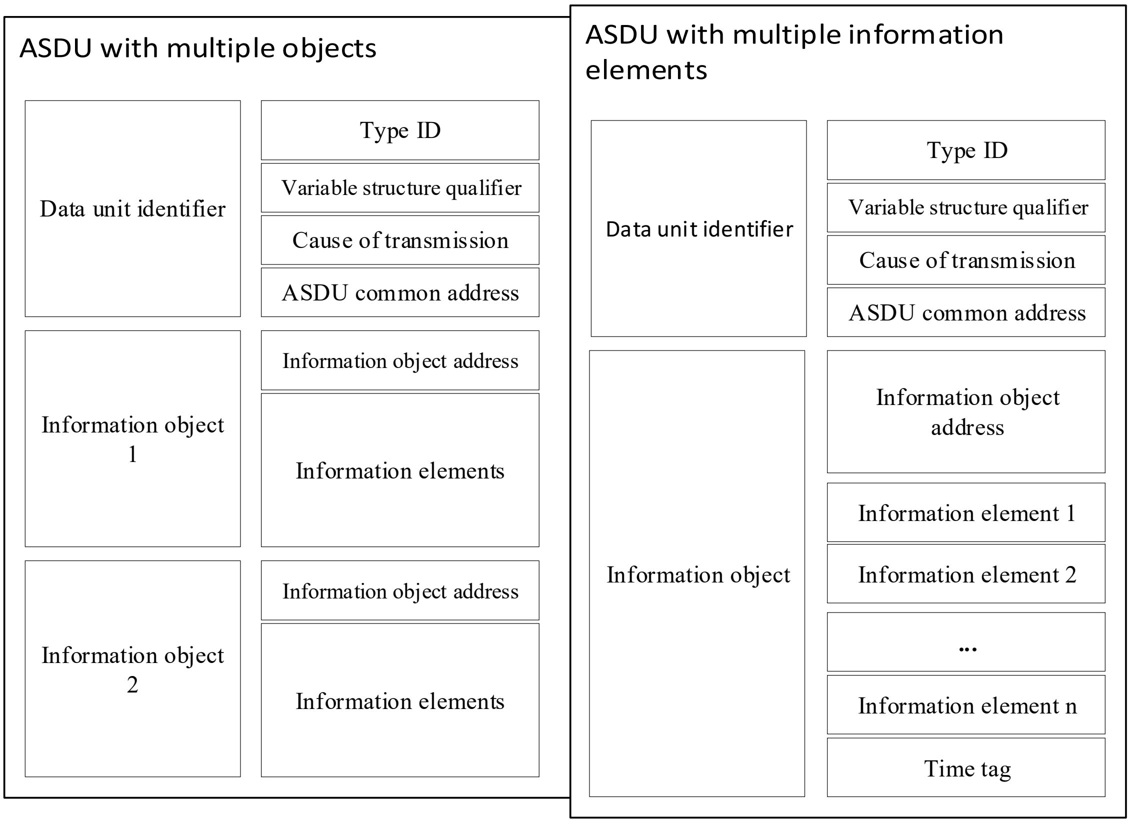

Figure 25. *IEC 104 and 101 ASDU types [53].*

The first module in the ASDU structures is data unit identifier that contains type of the data, destination and extra information about the data. In data unit identifier the first element is Type ID that can have a type codes between numbers 1-126 to define information object's purpose. The information object's purpose can be controlling, monitoring or file transferring. Variable structure qualifier (SQ) tells, if ASDU includes several information objects or information elements. In Figure 25 ASDU on left side includes several information objects, whereas ASDU on the right side includes one information object, which contains several information elements. Cause of transmission (COT) element routes the message in communication network and within the station to an intended task or program. COT originator address is needed in systems that has more than one control station. Common Address of ASDU is often referred as station address, which is an address to identify a slave stations and the address is unique for each slave.

The second module in ASDU structure is information object. One ASDU can hold several information objects, which depends on the type of ASDU. In information object the first element is information object address (IOA) that identifies particular information in the controlled station [51]. The second element in information object is information element that holds the data concerning the observed data point, like current measurement value. One information object can hold several information elements, which depends on the type of ASDU. The last element in the object is time tag, but it is not necessary.

To define communication between different vendors devices, IEC 104 provides interoperability guide, which offers selection of parameters that vendors can implement in their devices. The standard offers a document that vendors can use to present supported functionalities of their devices. Structure of interoperability guide is described in Figure 26 below. The first section in the interoperability guide contains information about the device, whereas sections network configuration, physical layer and link layer are not included to the IEC 104 protocol. Application layer section presents ASDU elements and the last section presents basic application functions [52]. In the interoperability guide, parts that are only presented in IEC 101 are strike-through and the check box is marked with black colour.

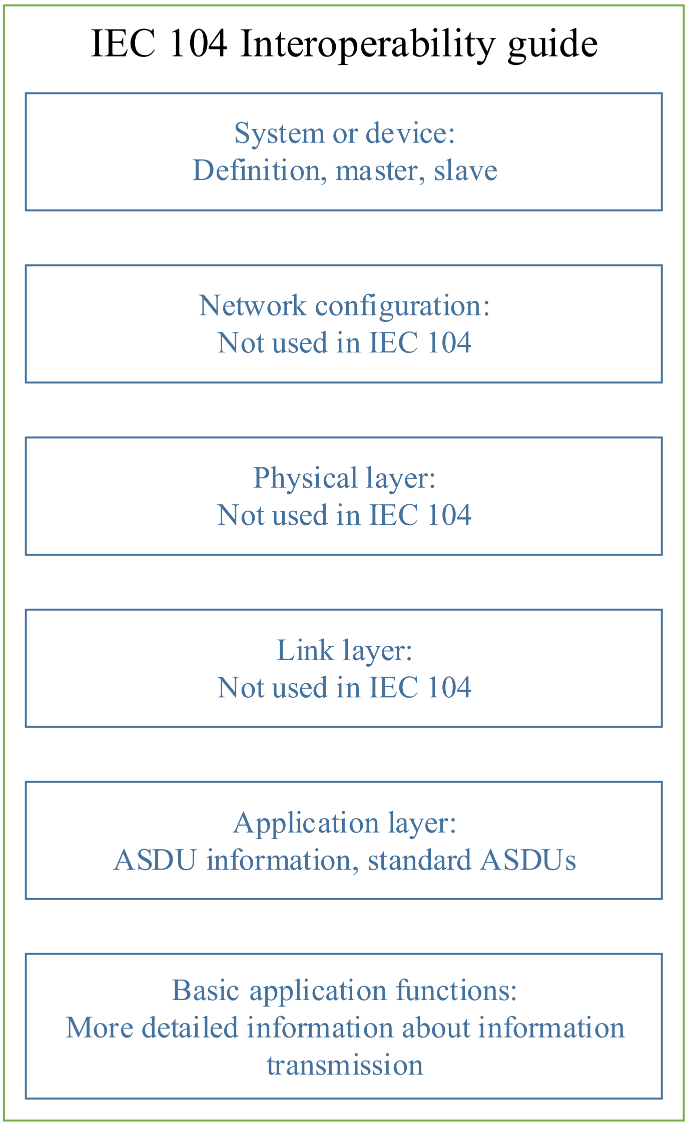

Figure 26. *IEC 104 interoperability guide structure [52].*

3.4.5 OPC

OPC is a standard for data exchange between separate automation systems, it is widely accepted standard in industries and common in SCADA systems. [53]. The standard is developed and maintained by OPC Foundation. OPC is divided to Classic OPC and new OPC Unified Architecture (UA). Classic OPC is still widely used in industrial automation systems [54].

Classic OPC was developed in the 1994. The reason for the development was the need for standardized communication specification in automation systems. The Classic OPC is based on server-client model and it is designed on Microsoft Windows platform [53]. Classic OPC offers data interfaces which are Data Access (DA), Alarms and Events (A&E), History Data Access (HAD) and few other specifications for external use. DA interface is for reading, writing and monitoring for process data. DA is the most used interface form Classic OPC. A&E interface is meant for sending notifications from server to client and HAD provides access to history data, whereas DA offers real time data.

Classic OPC is platform dependent, whereas OPC UA is platform independent. The problem with interoperability was seen as a problem with Classic OPC. XML-DA was developed for Classic OPC to solve the interoperability issue. Unfortunately, XML-DA did not provide as good performance as DA [53].

From OSI model perspective, OPC UA is located on the application and application process layers. OPC UA information model describes rules and building blocks for the data, and OPC UA is based on object-oriented design [53]. In addition to standardized information model parts, vendors can specify their own parts. The standard provides base information model, which can be extended with vendor specific information [54]. The detailed description of OPC UA information model, for developing OPC UA applications, is presented in standard IEC 62541.

3.4.6 DLMS/COSEM

DLMS/COSEM is specification for meter communication in electricity, heat, thermal energy, gas and water industries [55]. The protocol is often described as tree steps where the first step is COSEM information model, the second step is accessing COSEM objects with DLMS services and the third step is accessing communication medias.

DLMS/COSEM is published by DLMS User Association that provides the basics from the protocols in Green Book and Blue Book. Blue Book defines COSEM information model and Green Book specifies accessing and transporting the data. In electricity metering, DLMS/COSEM is also known as IEC 62056 standard and it is maintained by DLMS User Association [55].

COSEM is the information model for metering data and it is based on object-oriented design [56]. In COSEM the metering data is stored into objects that are created from interface classes that are based on COSEM template class model. COSEM template model presents basic elements that interface classes can include. Interface classes implement behavior of objects by defining attributes and methods for objects, whereas object represent the real data.

COSEM objects are identified from each others with a logical name that is known as Object Identification System (OBIS) code. In Figure 27 below, two Register objects, which are Total positive active energy and Total positive reactive energy, are created from the interface class Register. Objects' logical names are OBIS codes and objects' value is information about the instance. The figure presents how are meter values, reactive energy and active energy, saved to Register objects 1 and 2. To use COSEM object, the user do not need to know the implementation of the class from which the object is created. The user has access to the methods which are interface to access objects attributes.

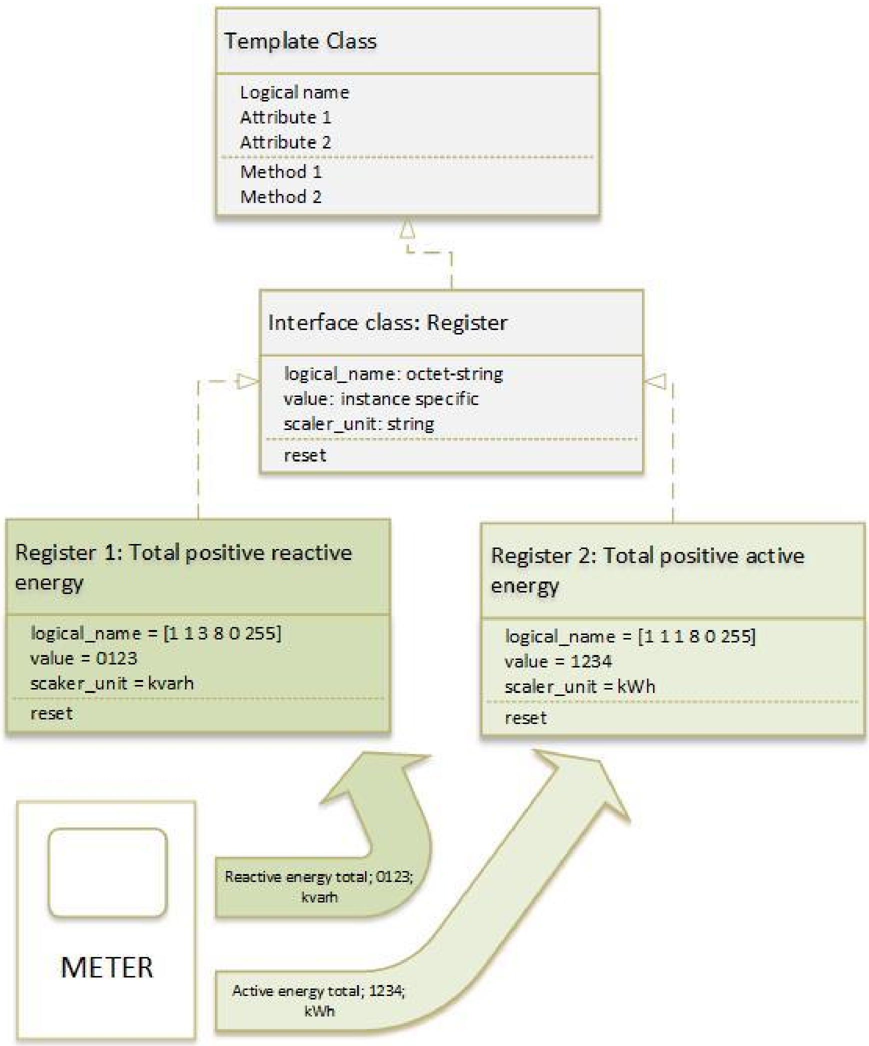

Figure 27. *COSEM classes and objects [57].*

OBIS code is 6-byte identifier, which describes the data that the object is holding in. OBIS code bytes come from value groups that are designated with letters from A to F [58]. Value group A identifies energy type, B identifies the measuring channels, C identifies the physical quantities, D identifies country specific identifiers and applications, E is for further classification and F identifies historical values. OBIS codes have pre-defined meaning and these meanings can be found from DLMS User Association website [59]. Figure 28 below illustrates how OBIS codes are formed. In the figure, value groups are located on the top, the possible numerical identifiers are located on the middle and OBIS code is on the bottom.

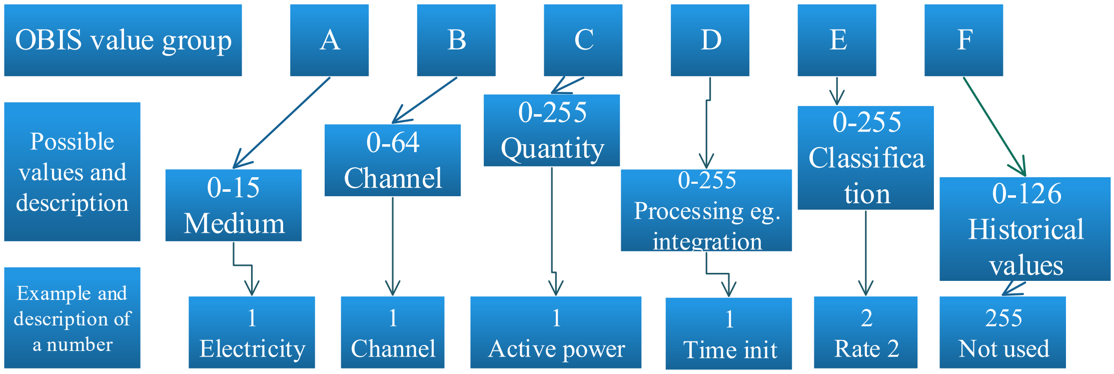

***Figure 28.** OBIS code [57].*

COSEM objects' elements are accessed with DLMS protocol. DLMS is application layer protocol, which provides services to access COSEM objects and secure connection between server and client. In addition to application layer, use of other OSI model layers depends on implementation of communication profile. One communication profile option is 3-layer stack that uses application, data link and physical layer. In the 3-layer profile, DLMS is located on application layer, HDLC on data link layer and physical medias on physical layer [60]. In 3-layer connection profile, metering devices are identified with HDLC physical address.

Data exchange is based on client-server-model in DLMS/COSEM. Client and server are separate devices, which communicate to each other [60]. Client is responsible of collecting data, whereas server is metering device, which provides the data. Client and server are able to communicate to each others with pull or push operations. In pull operations client application does requests to server to which server responses, whereas in push operation server application sends pre-defined information to client.

4. LABORATORY IMPLEMENTATIONS

Laboratory implementations present three areas from the course Distribution Automation. These areas are substation automation, information systems and customer automation. In laboratories, students get touched with real distribution network devices. Each laboratory can take approximately two hours.

Substation automation laboratory offers understanding from IED functionalities and distribution protection functions. Laboratory tasks and protection fundamentals are same as in previous implementation. Upgraded features are protection technology, protection functions, IED functionalities, IEC 61850 and new outlook.

Low voltage network laboratory combines control center of the distribution network and the low voltage network. DMS and SCADA are used for visualizing network and control operations. Smart meter provides measurements from the low voltage network.

This chapter describes the laboratory environments. The First part describes substation automation laboratory and the second part presents low voltage automation laboratory.

4.1 Substation automation laboratory implementation

New implementation from substation automation laboratory changes technical side of laboratory. In the new implementation, IEDs are more tightly bounded with simulation model.

The laboratory environment is presented in Figure 29 below. The figure is divided into three sections that are simulations, amplifiers and substation automation. Simulation section presents simulation environment. Simulations are done by RTDS hardware and controlled with PC. PC is also used for IED configuration and reading disturbance recordings from IEDs. Simulations current and voltage measurements are amplified for IEDs to present instrument transformer values. Substation IEDs simulate busbar and feeder protective devices. Communication between IEDs is made with IEC 61850 and both protective devices have capability to operate circuit breakers. Circuit breakers are possible to operate with tripping function or from IEDs’ LCD screen with push buttons.

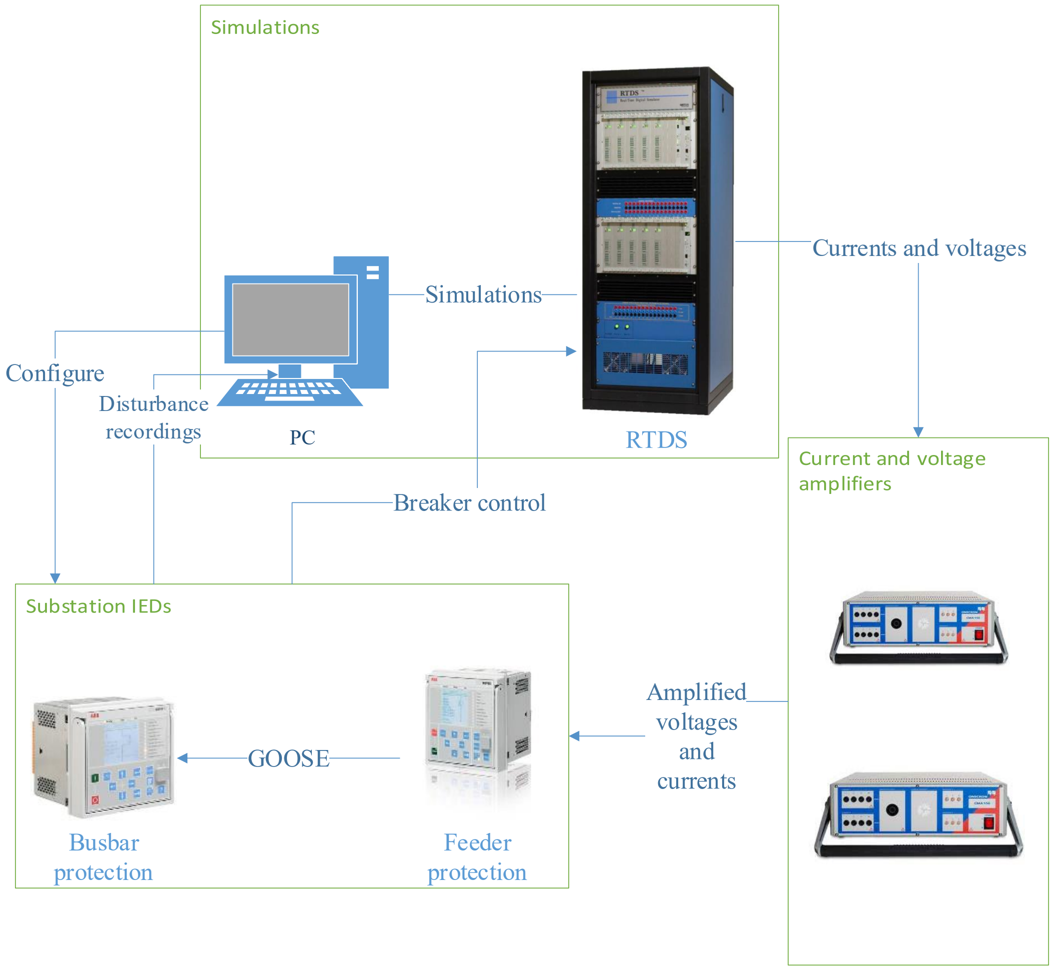

Figure 29. *IED laboratory environment [61-63].*

4.1.1 IEDs

Laboratory implementation consists of two REF615 feeder protection IEDs. One IED is located at an incoming feeder and the other one at an outgoing feeder. Structure of the protection was chosen according to network topology at the previous laboratory implementation. Protective functionalities fulfil SFS 6001 requirements and are simple to configure. Idea of the laboratory is to see IED in function and learn principles of distribution network protection. Protection devices are presented in Figure 30 below.

Figure 30. *REF615 protection devices in the laboratory.*

REF615 functionalities are depended on order code. The presented IEDs are F variants and have directional overcurrent, earth fault, voltage and circuit breaker condition monitoring protection applications. IEDs have analog inputs and outputs for phase currents, residual current, phase voltages and residual voltage. Devices have 16 binary inputs and 10 binary outputs. 100Base Ethernet is supported in communication. Communication protocol is IEC 61850. Operation voltage can be between 48-250V direct current or 100-240V alternating current.

REF615 provide wide range of functionalities and used functionalities were chosen according to laboratory needs. In the laboratory there are needed directional overcurrent, earth-fault protection and circuit breaker protection functions. Blocking signal is send with GOOSE messages and faults are recorded with disturbance recorder. Operations, measurements and faults are indicated with LEDs and from LCD screen. Circuit breakers control are made with binary outputs and indication with binary input terminals. Current and voltage measurements are measured from phase values and wye connected at IEDs. Residual voltage and current are calculated from fundamental frequency phasors, because of using calculated values reduces need for hardwire connections. Also, in the laboratory environment, it is possible to use calculated values instead of measured values, because simulations use ideal network. When residual current and voltage are calculated at REF615, voltage measurement must be wye connected at IEDs' terminals.

Overcurrent protection is made with directional overcurrent function. Directional properties of protection are not in use, because of one input feeder at the substation. Overcurrent protection has two stages for low and high overcurrent. Low set stage is for over load conditions and small fault currents. High set stage is for high fault currents, such as short circuits at beginning of the feeder. Protection functions' start signals are forwarded to disturbance recorder and operation signals are forwarded to disturbance recorder, tripping logic, indication LED and circuit breaker. The busbar protective device's overcurrent high set stage operation is possible to block with GOOSE message that is sent from the feeder protective device. At the feeder protective and the busbar protective IEDs the protection current and operation delay settings are same as in previous laboratory environment implementation. Previous settings provide required sensitivity and selectivity for laboratory protection purposes. Protection settings are modified to correspond new instrument transformer ratios. Voltage transformer ratio is 0,1/20kV and current transformers ratio is 1/280A.

Earth fault protection is implemented with directional earth fault protection function and voltage protection function. Directional earth fault protection is used at the feeder, without directional protection functionality and with residual current setting. Voltage protection function is applied at busbar protective IED, and voltage protection is based on residual voltage. Earth fault protection functions send start signal to disturbance recorder and operation signals are send to disturbance recorder, trip logic, circuit breaker failure protection and indication LED.

GOOSE message provides selectivity, when time delays is not possible option. In the laboratory environment, the feeder protection IED sends blocking message, if its high set stage protection starts. Block message is sent to busbar protective device that has GOOSE receive function. At the busbar IED, GOOSE receive block has output for validation, which checks that GOOSE communication is valid. If communication is not in operation, LED informs the user about the fault. GOOSE message includes a protection function value and a quality value, which is general rule [50].Values IEC 61850 names are LD0.DPHLPTOC.Str.general(ST) and LD0.DPHLPTOC.Str.q(ST).

Disturbance recorder documents protection operation. Both protective devices have disturbance recorder which have signal inputs from all protection functions. In addition to protection function, circuit breaker close and open signals, phase currents, phase voltages, calculated residual voltage and calculated residual current are recorded. Recording is started, only if any protection function sends operation signal. At this way amount of recordings are reduced. Reduced amount of recordings aid in searching for recording when students make fault simulations.

In laboratory's IEDs recording length is set to minimum. Disturbance recordings are edge based recording with fixed length. Recording length is 120 cycles from which pre-triggering time is 30%. Storage rate is 32 samples per cycle. One cycle is 20ms in 50Hz system. Recording with 120 cycles, recording length is 2,4s. A practical recommendation for recording time for REF 630 IED is 2s + fault duration + 3s [17]. In chosen recording length pre-triggering time is 800ms, which is enough to record the whole operation time of protection function with longest time delay. At busbar IED, earth fault time delay length is 600ms plus operation delay 30ms. With presented recording length is possible to record the whole system operation.

Local human machine interface (LHMI) presents protection operation and switching state of feeders. Protection functions operations are presented at LCD screen and with LED indicators. LEDs are latched on when protection function operates. Switching devices are presented as SLD diagram on screen and circuit breaker is possible to operate with LHMI buttons. Instrument transformer measurements are possible to see from LCD screen.

4.1.2 Simulation environment and connections

Simulations are executed on RTDS. The simulation model is similar as in previous implementation of the laboratory. Added functionalities into simulation model are circuit breaker indication and control, and measurements.

Breaker control and indication signals to and from RTDS are controlled with GTFPI card. GTFPI card has two physical input-ouput-panels in which circuit breaker control and indication signals wires are connected to. Panels are Digital I/O panel and High voltage panel. Digital I/O panel's operation voltage is 5V, whereas High Voltage panel operates with 48 V voltage source. Figure 31 below presents GTFPI card.

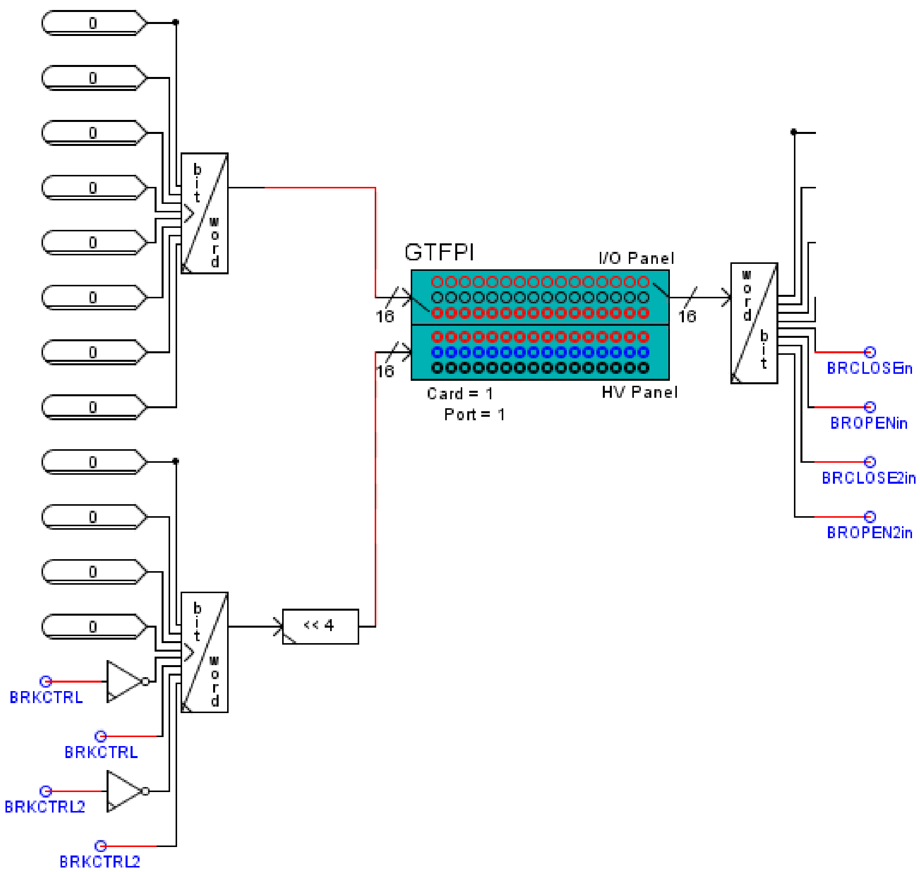

Figure 31. *RTDS inputs and outputs.*

Indication signals from breaker are located on left side and control signals from IED are on right side of Figure 31. Circuit breakers’ open and close indication signals are connected to bit to world component where close indications are connected through inverse logical port. With presented implementation, one signal can present both close and open indication signals. Indication signals are connected to GTFPI High Voltage panel, because REF615 binary inputs’ operation voltage is between 24-100V. Control signals are received from GTFPI digital panel.

Circuit breakers control signals are forwarded to circuit breakers control logics from GTFPI block. Circuit breaker control logic is presented in Figure 32 below. In breaker control logic, a pulse generator is activated from control signal. When the pulse generator is activated its output is set to one for 10ms. 10ms is enough for S-R Flip Flop to react change in its input. Flip Flop execution time is 0,55ms. S-R Flip flop output changes, if its inputs changes and output will not change, if same input is activated as previous time. Circuit breaker logic remembers its last stage and sequential activation with help of S-R Flip Flop. Flip Flop’s output is connected to delay block that simulates circuit breaker operation delay, which is set to 20ms. Delay block is connected to signal that is connected to status information and circuit breaker model. Status information and circuit breaker models signals are located under circuit breaker control logic in Figure 32. Multiplication blocks are needed because of the simulation software, because signals are always connected to other signals trough other simulation functions in RTDS Draft program.

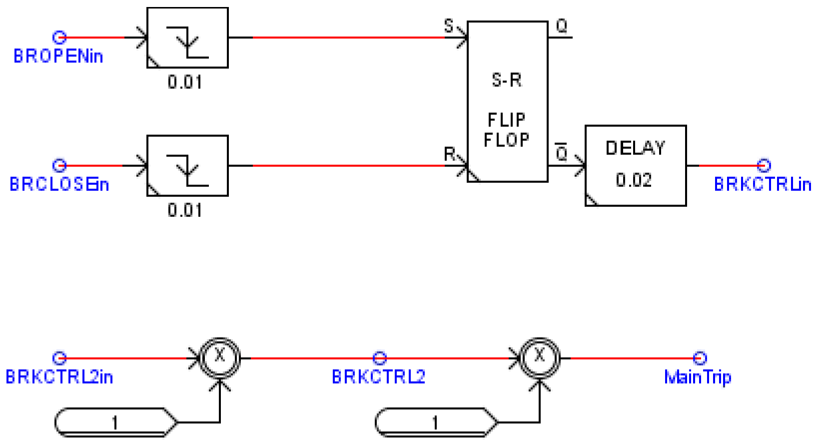

Figure 32. *Breaker control signal detector.*

Current and voltage measurements are connected to amplifiers from RTDS through GTAO analog output card. Output signals are millivolts which are needed to amplify to get real values of measurement circuit for IEDs. Current measurements are scaled with value 7 and voltages are scaled with value 50 when taking into consideration the amplifier amplifications that are 50 for voltage and 5 for current. Nominal phase voltage of simulation model is 11,547kV, which is 57,735V in secondary side. Primary current’s nominal value is 280A, which is 1A on secondary side. Voltage and current output signals are limited to prevent hazardous currents and voltages that could damage the amplifier. This may cause difference between simulation model and disturbance recording measurements.

For measurement purposes, RTDS provides IEC 61850 sample values. Sample values would reduce the amount of hardwires and the amplifier would not be needed. Sample values are not used in this laboratory environment, because REF615 does not fully support measurement with sample values. Only voltage measurement is supported. In addition, laboratory's router do not include support for IEC 61850 sample value.

4.2 Low voltage automation laboratory

The laboratory environment of low voltage automation is constructed from two systems. One system covers AMI system and other system covers substation automation.

AMI system structure is presented in Figure 33 below. Low voltage network is simulated with RTDS simulator. Currents and voltages are amplified for smart meter at OMICRON amplifier. Smart meter and gateway communicate with DLMS/COSEM. Gateway pulls metering data from smart meter every three seconds. Gateway and SCADA communication is implemented with IEC 104 and SCADA pulls metering data from gateway. SCADA operates as AMI MDMS, which provides data to DMS through OPC interface software.

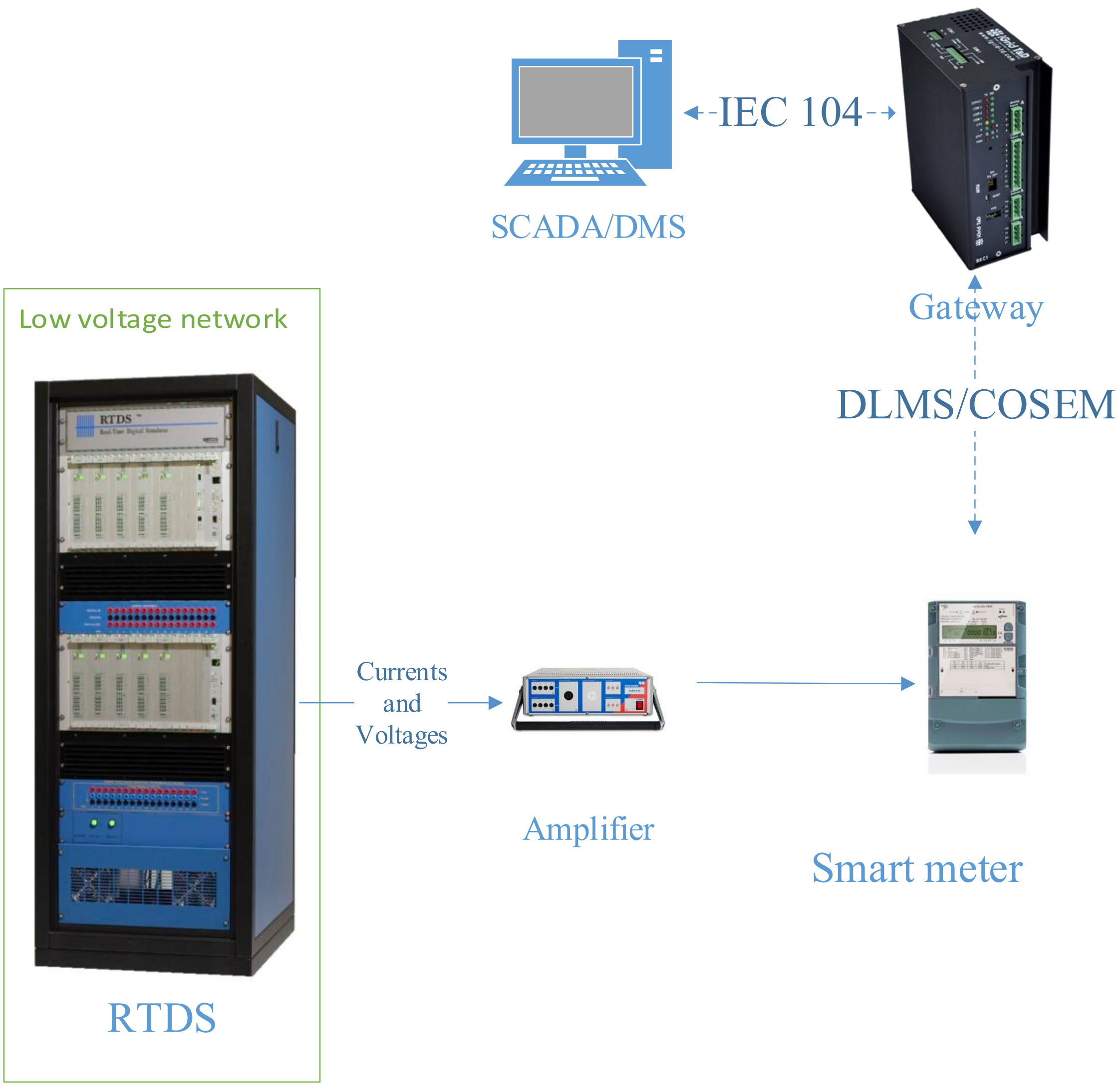

Figure 33. *AMI system structure [41, 61, 62, 64].*

Substation automation system is presented in Figure 34 below. RTDS simulates substation devices and substation RTU has two-way communication to RTDS. RTU forwards status, measurement and command information. Communication between RTDS and RTU is implemented with IEC 104. RTU and SCADA also have bi-directional communication with IEC 104. SCADA collects substation data and presents it in UI on single-line-diagram (SLD). DMS get substation state information from SCADA, and DMS uses the data from SCADA to presents the distribution network topology and state on a map.

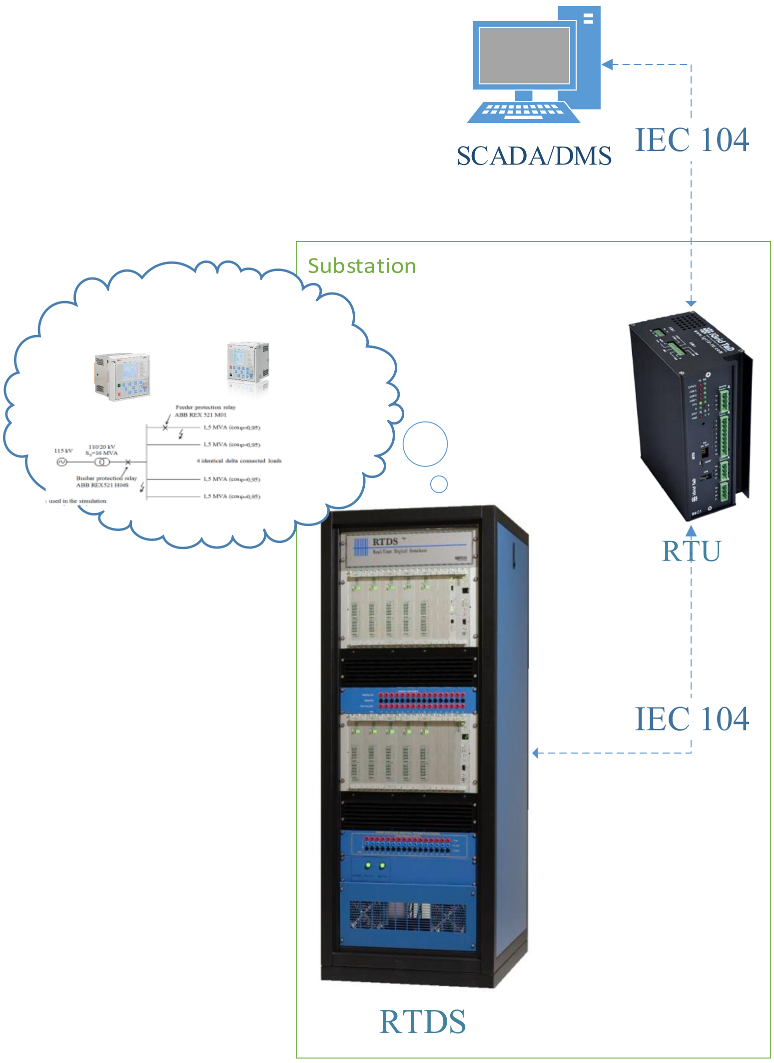

Figure 34. *Substation automation system [62-64].*

Following subsections describe more precisely the laboratory environment. The subsections present the laboratory environment from device level.

4.2.1 Simulation environment

New laboratory environment's simulation model is similar to the previous laboratory environment's model. The new model is appended with three feeders, IEC 104 signal block, circuit breaker control logics and medium voltage measurements.

RTDS supports IEC 104 protocol that is added to the simulation model with GTNET-IEC104 block, which is presented in Figure 35 below. GTNET requires parameters to establish connection. Required parameters are a common address of ASDU, IP address of a master station, port number for TCP connection and a point file where IEC 104 process points are configured for RTDS.

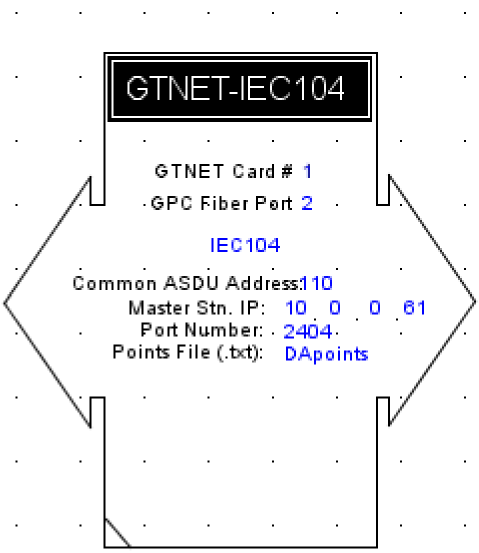

Figure 35. *IEC 104 communication block.*

GTNET-IEC104 does not support the whole standard. Interoperability guide defines supported features for GTNET [65]. Table 3 presents supported process information ASDUs.

Table 3. *Supported ASDUs for process information [65].*

Supported process information ASDUs	
Monitor direction	**Control direction**
Single-point information	Single command
Measured value, short floating point value	Set point command, short floating point value
Single-point information with time tag CP56Time2a	

In simulation model IEC 104 standard is used for medium voltage bay level process points. Process points include circuit breaker status and commands, busbar voltages, feeders' currents, residual currents and voltage. Fuse blow alarm simulation use IEC 104 from the low voltage network.

Simulation environment contains five breaker control logics from which one is presented in Figure 36 below. The idea of the control logic is to receive commands from SCADA, process the operation command, send processed command to circuit breaker and provide breaker status information.

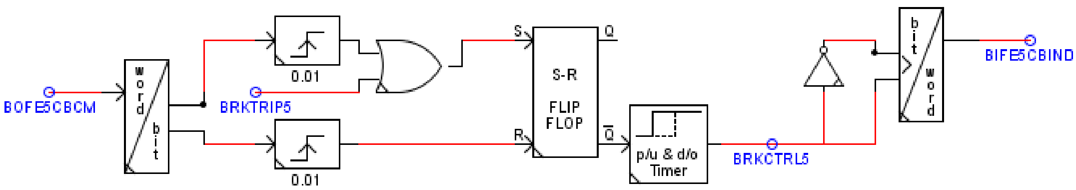

Figure 36. *A breaker control logic from simulation model.*

Figure 36 breaker module is built with RTDS component library's blocks. Word-to-bit block converts command signal to logical form. In world-to-bit block, open command is least significant bit (LSB) and close command is most significant bit (MSB). Next component is timer block from word-to-bit converter. Timer sets its output to one for 10ms when it triggers. The figure's OR gate has inputs from open command and relay trip command. Protection relays are not used in the laboratory exercise. Next from OR gate is S-R Flip Flop which stores the previous state information. Operation of S-R Flip Flop was explained in part 4.1.2. Flip flop's outputs affect to the begin state of the breaker. In presented modification, Q inverse is set to zero in the beginning of simulation. By setting Q inverse to zero, the breaker is open when simulation is started. Flip flop is followed by timer block which simulates breaker operation delay. Breaker operation delay is 30ms in simulation. Breaker control signal is send with BRKCTRL5 block and status information is transferred with bit-to-world block where LSB is open indication and MSB is close indication.

4.2.2 Smart meter

The laboratory environment uses LandisGyr E650 smart meter. The meter receives measurements from RTDS through the amplifier. LandisGyr meter sends measured values to gateway that works as data concentrator.

The smart meter is LandisGyr ZMD405CT44.0457 S3 B32. The meter is suitable for different voltage levels, but the meter is generally used by large consumers. The meter is designed to use instrument transformers in current measurement and sometimes in voltage measurement. In communication, the meter can use several protocols of data link layer, such as Ethernet and HDLC.

Circuit diagram from current and voltage measurements is presented in Figure 37 below. Voltage and current inputs are from OMICRON amplifier. Voltage transformer's ration is 100/400V and current transformer's ratio is 5/100A.

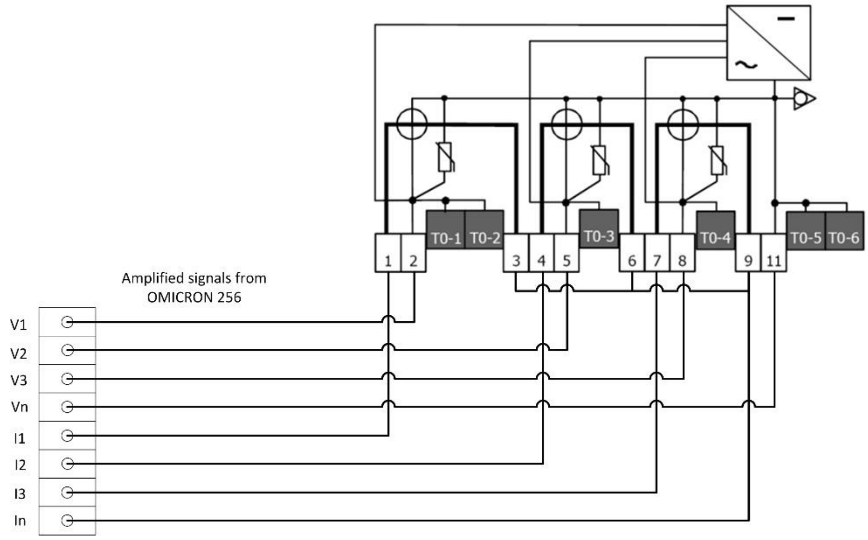

Figure 37. *Measuring circuit diagram.*

Currents and voltage measurements are from GTAO card of RTDS. GTAO card outputs are scaled with factors 0,5 for current and 0,99593 for voltage in the simulation model. OMICRON amplifier transfers the values to real instrument transformer values for the meter.

The smart meter supports DLMS/COSEM in communication. Meter supports specifications that are determined by official standards. These specifications are DLMS physical layer, DLMS link layer with HDLC definition and DLMS/COSEM application layer.

The meter is accessed by HDLC address. In LandisGyr meters physical HDLC address is last four digits of the meter's device number plus 1000. HDLC address can get values between 1000 and 10999.

Accessing DLMS/COSEM objects, the DLMS master needs OBIS codes of COSEM object. LandisGyr meters use shorten format from OBIS codes and supported codes are listed in device's User Manual [66]. In addition to User Manual, standard OBIS codes are listed in DLMS User Association's website [67].

4.2.3 Data concentrator and RTU

In the laboratory, data concentrator and RTU units are integrated into one device. In the normal distribution network, smart meter data is not send through substation RTU. In the laboratory environment, one unit is enough to transfer all the data that is sent from smart meter, RTDS and SCADA.

The laboratory environment uses iGW communication gateway, which is manufactured by iGrid T&D. Gateway functions are similar as RTU's functions, but gateway does not provide I/O capability. In communication iGW uses Ethernet on data link layer, and it supports several SCADA protocols and DLMS/COSEM. In the laboratory environment, iGW uses IEC 104 and DLMS/COSEM in communication where IEC 104 is used in communication to RTDS and SCADA, whereas DLMS/COSEM is for communication with the smart meter.

Communication from iGW to RTDS is done with IEC 104, in which iGW operates as IEC 104 client and RTDS as server. RTDS model provides substation measurements and circuit breaker status signals, and RTDS receives SCADA's open and close commands are from iGW. For signals iGW provides five signal groups, from which three are used: digital input, digital output, and analog input. Digital input signals are single-point information ASDUs, which are used for status indication, digital output signals are command signals, which are single-command ASDUs with select-before-operate command, and analog inputs are short floating point values, which are used for measurements. All signals need information object addresses (IOA) which are from configuration text file of RTDS IEC 104 process points. iGW's IEC 104 related settings are from IEC 104 interoperability guide and iGW configuration default values.

Communication between iGW and smart meter is done with DLMS/COSEM where iGW operates as client device with three second pulling frequency. From smart meter OBIS codes, iGW supports only measured and energy codes. Measurements are 32 bit and 64 bit signed values where energy measurement is only 64 bit scaled value and it is read as counter input at iGW. Other smart meter values are analog inputs.

SCADA and iGW connection is established with IEC 104 where iGW operates as slave device. Protocol was chosen for this purpose, because IEC 104 is common protocol between SCADA and RTU. RTDS IEC 104 values and the meters values are mapped at RTU on IEC 104 to SCADA. Smart meter ASDUs are short floating point values and integrated totals without time tags. Substation ASDUs are same as between at iGW IEC 104 master and substation. IOA values are 8000-> for digital inputs, 8050-> for commands, 7000-> for analog inputs and 2008 for counter inputs.

4.2.4 SCADA

ABB MicroSCADA Pro SYS600 is used as SCADA in the laboratory environment. The role of the system is to present SLD on UI, operate breakers, get process data from gateway, forward process data to DMS and manage communication.

SCADA presents system picture in SLD diagram on UI. Substation picture is presented in Figure 38 below. The SLD diagram presents all the fundamental substation components, which are line disconnectors Q1 and Q2, circuit breaker Q0, earth switch Q9, and current and voltage transformers. Component symbols are chosen according to how well they present the functionality. Chosen components present well the open disconnectors, because those resemble switches. Components status change depending on substation simulation, commands are possible to send by clicking a symbol and measurements are updated next to instrument transformer symbols. In the beginning of the feeders is showed text “Remote”, if feeder is controlled remotely. Substation feeders color changes according to current topology. Topology is imported from DMS through OPC interface program.

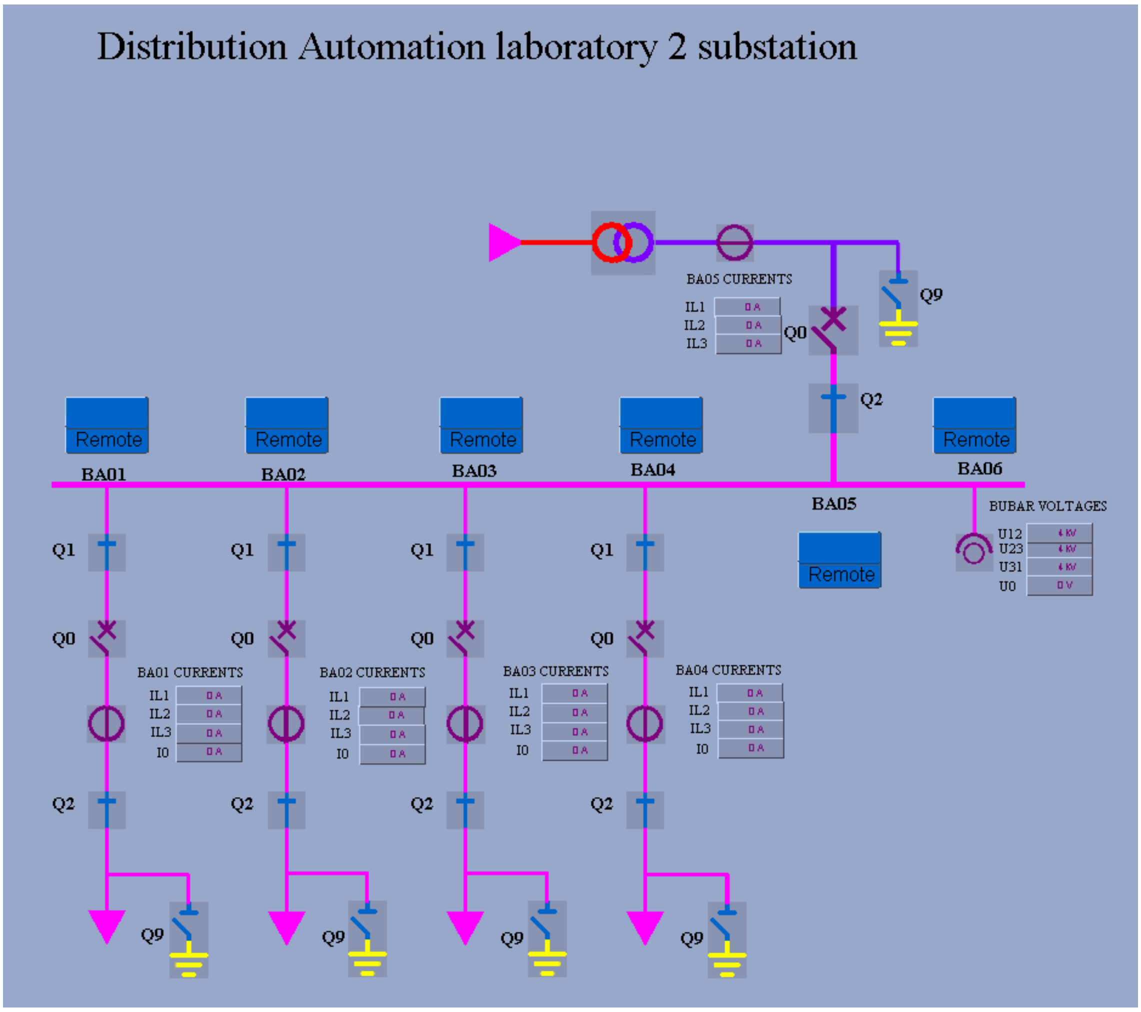

Figure 38. *SCADA SLD.*

System process data is saved to process objects that are part of Application object. Process objects are created with standard function tool, which can be used to create standard process objects. Substation process objects are circuit breaker status and commands, voltage transformer measurements and current transformer measurement. Indications are created as single indication ASDU, measurements are floating point ASDUs and commands as single command ASDUs. AMI system information is collected to manually created process objects, which are floating point ASDUs and integrated total ASDU. In AMI process object indexing, DMS intermediary file of metering data impacts to index numbers.

From process objects, circuit breakers are only components that are possible to control. Circuit breaker symbols get open and close information as separate signals as well as circuit breaker commands are send as separate signals. Commands are direct commands with binary output signal and indication signals are binary inputs. ASDU types are single commands without time tags and single indications without time tags although ABB's manual recommends to use time tagged values, whereas IEC 104 standard recommends to use time tag in the systems where time delay could be a problem. In the laboratory environment, topology of the communication network is small. For this reason time delay is not considered as a problem. The second reason, for not using time tagged values, is clock synchronization. Clock synchronization could cause problems, if devices' clocks are not synchronized. In IEC 104 time tagged commands will not be proceeded, if command receiver notices that command has arrived after allowed delay [52].

Communication between SCADA and DMS is done through OPC interface program where AMI system, switching indication and topology management has own OPC classes. Substation components' OPC objects are generated automatically with SCADA's import function, but AMI and topology objects are needed to create manually.

4.2.5 DMS

In the laboratory environment, DMS presents the distribution network topology on a background map. DMS gets network and process information from database and SCADA. SCADA communication is done through OPC interface program which was presented earlier.

In the laboratory environment, DMS uses the background map, which is on default in the software. The map picture is from the city of Virrat, Finland. Substation is located on area where was not earlier network infrastructure. The new network structure includes same parts as the simulation model. Low voltage customer point presents measured quantities of the smart meter and measured quantities are presented as they are configured to the intermediary file. Network components and lines of simulation model are chosen from default DMS components, which means that electrical values of network components do not correspond to simulation model values. This has no effect in the laboratory environment, but network components' parameters should be changed to correspond the correct values, if network calculation are wanted to take as part of the assignment for example.

In DMS, AMI intermediary configuration file provides information from AMI process data for DMS. The file lists process points in measurements and events that include information about description and index of process points. All the smart meters measurements and RTDS's fuse blow event are configured into the interoperability file.

5. TESTING LABORATORY ENVIRONMENTS

This chapter presents laboratory test phase and investigates the results. Laboratory environments are tested to verify correct operation in exercises. Substation automation laboratory is tested in fault situations, whereas the operation of smart meter laboratory is verified in normal conditions and in neutral conductor fault.

5.1 Fault simulations in distribution network

The substation automation laboratory exercise includes detecting of protection sensitivity, selectivity and back-up protection. The normal operation, short circuit faults, earth faults and blocking message are analyzed to approve functionality of the laboratory. Circuit breakers should be possible to operate in normal conditions with IEDs. IEDs' protection functions are not allowed to operate in normal conditions. Current protection settings are designed to detect the rated currents. The rated currents are maximum load current, two-phase fault in end of feeder, three-phase fault in beginning of the feeder and three-phase fault at busbar. Earth fault sensitivity requirement is set to 1000Ω fault resistance. When feeder length is increased to 200km, protection should not detect faults at the end of the feeder, because the sensitivity is set to detect faults at 50km feeder. Protection devices should operate only to faults that are at the protection area of device. The selectivity is provided with time selectivity and block message.

Table 4 below presents normal load current and voltage values in the network. Current values are measured at the busbar and the feeder. Voltage measurements are from busbar. RTDS values are steady state measurements that are read from RTDS meter block. IED values are from IEDs UI. The simulations present the operation of circuit breakers to make sure how circuit breakers and IED operate in normal load conditions. In the first three simulations, the feeder breaker is operated, in simulations four and five, the busbar breaker is operated, and in the last simulation, the network length is changed.

Table 4. *IEDs operation in normal conditions.*

Simulation cases	RTDS					IED			
	Busbar			Feeder		Busbar		Feeder	
Description	Current (A)	Voltage (kV)	U0 (kV)	Current (A)	I0 (A)	Cur-rent (A)	Voltage (kV)	Cur-rent (A)	Voltage (kV)
Normal load condition, breaker close operation	162,1	11,9	0	40,5	0	161,7	11,9	40,4	11,9
Normal load condition, feeder breaker open	121,9	12,0	0	0,0	0	121,7	11,9	0	12,0
Normal load condition, feeder breaker fault, open operation	162,1	11,9	0	40,5	0	161,8	11,9	40,4	11,9
Normal load condition, bus-bar breaker, open operation	0	0,1	0	0,0	0	0	0,0	0	0,0
Normal load condition, bus-bar breaker fault, open op-eration	162,1	11,9	0	40,5	0	161,9	11,9	40,4	11,9
Normal load condition, feeder length 50km->200km	153	11,9	0	31,3	0	152,7	11,9	31,3	11,9

IEDs' measured current and voltage values are close to RTDS measured values in normal conditions. Residual current and voltage are zero in normal operation state. Circuit breakers were possible to operate open and close from IEDs. When feeder breaker was open and busbar breaker was closed, feeder IED's current measurements were zero and voltage measurement presented the voltage value at busbar, and busbar protection IED presented current and voltage values. When busbar breaker was open and feeder breaker was closed, both protection devices' measurements presented zero. In some cases was noticed, that in the beginning of simulations, low set stage of overcurrent protection started at both protection devices. Inrush detector could prevent exceeding effective start value in the beginning of simulations [23].

Table 5 below presents short circuit fault currents and protection operation time at busbar and feeder circuit breakers. RTDS column values are calculated from fault current steady state peak values by dividing the peak value with square of two. IEDs column values are from disturbance recordings. Simulation cases present two- and three-phase faults at the outgoing feeder. Fault locations are 10km and 50km from primary substation. Two-phase faults are simulated between phases A and B. Simulation cases cover all rated faults and increase of feeder length. Busbar protection IED disturbance recording configuration is modified to start recording when protection starts for these simulations.

Table 5. *Short circuit faults.*

Simulation cases	Calculated		RTDS		IEDs			
	Busbar	Feeder	Busbar	Feeder	Busbar		Feeder	
Description	Current	Current	Current	Current	Current	Operation	Current	Operation
Two-phase short circuit AB 50km, time selective	494,7	370,4	493,0	367,0	475,7	Start	355,9	0,452
Three-phase short circuit 50km, time selective	552,0	427,7	523,3	422,1	546,7	Start	442,5	0,438
Two-phase short circuit AB 10km, time selective	1530,7	1406,5	1499,8	1411,4	1650,0	Start	1533,0	0,103
Three-phase short circuit 10km, time selective	1748,3	1624,0	1668,6	1623,9	1571,0	Start	1687,0	0,102
Two-phase short circuit at busbar AB, time selective	3781,8	X	4674,5	23,4	2516,5	0,236	X	No
Three-phase short circuit at busbar, time selective	4366,8	X	5976,3	0,0	4270,0	0,239	X	No
Two-phase short circuit 50km->200km	191,7	97,8	226,1	108,0	223,8	No	104,1	0,44

In Table 5 calculated fault currents are close to RTDS values and IEDs values in cases where fault current is small. When fault currents increase, the difference between current values increase. Time selectivity functioned correctly. With small fault currents the time delay was longer than in cases were fault current was high. Busbar protection IED did not operate before feeder IED in feeder faults as well as sensitivity was set to correct level, because feeder protection noticed all rated faults. Busbar protection device also noticed the faults expect in 200km case which was expected. Extending the feeder length to 200km caused decrease in the fault current, and busbar protective device could not detect the fault anymore. Low set stage current protection of the feeder protection device operated to faults with 50km and 200km distance. High set stage of the feeder device operated to 10km faults. LHMI presented protection functions triggering with LEDs. If feeder length is wanted to extend to 200km, the busbar protection overcurrent protection low set stage would need to be re-calculated to fulfil requirements for overcurrent back-up protection.

Table 6 below presents measurements from earth faults. The first column includes values that are calculated with formulas 4 and 5 from subsection 3.1.4. The RTDS column values are from RSCAD Runtime environment and IEDs column are the busbar and the feeder breaker operations. Simulation cases present faults with different fault resistances. Fault resistances are 500Ω, 1000Ω and 3000Ω. The protection is designed to detect faults with minimum of 1000Ω fault resistance.

Table 6. *Earth faults.*

Simulation cases	Calculated		RTDS		IED			
	Busbar	Feeder	Busbar	Feeder	Busbar		Feeder	
Description	U0 (kV)	I0 (A)	U0 (kV)	I0 (A)	Operated	Time (s)	Operated	Time (s)
Line-to-ground fault feeder 50km, Phase A ,Rf=500 Ω	10,4	7,5	10,0	7,1	Start	No	Yes	0,454
Line-to-ground fault at feeder 50km, Rf=1000 Ω	8,3	6,0	7,9	5,8	Start	No	Yes	0,470
Line-to-ground fault at feeder 50km, Rf=3000 Ω	3,8	2,7	3,5	2,6	No	No	No	No
Line-to-ground fault at feeder 10km, Rf=500 Ω	10,4	9,5	10,6	8,3	Start	No	Yes	0,429
Line-to-ground fault at feeder 10km, Rf=1000 Ω	8,3	6,0	8,4	6,2	Start	No	Yes	0,472
Feeder length 50->200km, Line-to-ground fault, Rf=500 Ω	8,8	6,4	7,2	5,2	Start	No	Yes	0,457
Feeder length 50->200km, Line-to-ground fault, Rf=1000 Ω	5,9	4,3	4,1	3,3	No	No	No	No

In simulated earth faults, protection devices operated as expected. Both devices noticed faults with fault resistance 1000Ω and 500Ω with feeder lengths 10km to 50km. When feeder length increased to 200km, devices could not recognize rated 1000Ω fault resistance anymore. To detect faults with 1000Ω in 200km faults, this would need modification to sensitivity. In busbar faults voltage protection function operated at the busbar protection device. In all faults earth fault indication LED lighted up to inform about operation. Operation functions also lighted up the disturbance recording LED. The 3000Ω high fault resistance was not possible to detect with presented protection settings. Today, modern protection functions are able to detect fault resistances up to 10kΩ [12, 14], which is much better sensitivity than the laboratory was able to achieve.

Table 7 below presents operation of GOOSE block message in the laboratory environment. The busbar and feeder protective devices' operation delays are listed in the table. The table lists scenarios without blocking message, with blocking message and in communication failure. In the simulations high set protection operation delay is set to 100ms. The first simulation is done without GOOSE message to detect operation without blocking when time delays are non-selective. Two simulations present GOOSE message operation when time delay is set to smaller than 100ms at busbar protection IED. Time delays were set to shorter to detect operation of GOOSE message. Back up protection functionality is verified with feeder circuit breaker fault. GOOSE message should not block backup operation. A disturbance recording from simulation should present the whole operation of busbar protection device. In the last simulation case, communication between devices is disconnected. When communication is non-functional, busbar protection device should detect bad quality of GOOSE message, because this informs the user about communication malfunction.

Table 7. *GOOSE message operation.*

Simulation cases	IEDs			
	Busbar		Feeder	
Description	Operate	Time	Operate	Time
Three-phase short circuit 10km, without GOOSE	Yes	x	Yes	X
Two-phase short circuit 10km, GOOSE block message	No	No	Yes	0,096
Three-phase short circuit 10km, GOOSE block message	No	No	Yes	0,099
Three-phase short circuit 10km, GOOSE block message	No	No	Yes	0,096
Two-phase short circuit 10km, GOOSE block message, feeder breaker fault	Yes	0,650	No	No
Two-phase short circuit at busbar, GOOSE block message	Yes	0,134	No	No
Two-phase short circuit busbar, communication disconnected	Yes	0,134	No	No

Both devices operated without and with GOOSE message as expected. When time selectivity was set as non-selective, both devices operated in the feeder fault. Because the operation delay is reduced at busbar protection device, the block message is needed to receive selective operation. After enabling GOOSE message, the busbar protection device received block message from the feeder device. GOOSE message blocked the high set current protection function of the busbar IED. Blocking functionality worked also with shorter time delay than 100ms. In circuit breaker fault at the feeder, the busbar device operated as back up protection. Because block command blocks the high set stage operation of busbar IED, the low set stage of the busbar IED has still possibility to operate and remove the faulted feeder from the network. In communication malfunction the busbar IED noticed the bad quality of GOOSE message when communication cable was disconnected from busbar device. The busbar device indicated communication malfunction with LED.

Figure 39 below presents a disturbance recording from the busbar device. The simulated case is situation where the feeder circuit breaker has fault and there is two-phase short circuit in the network. The recording is based on pre-triggering setting. In recording pre-triggering time is 0-0,770 and post-triggering 0,770-2,4s. And more detailed, pre-fault time is 0-0,128s, fault length is 0,128-0,770s and post fault is 0,770-2,4s. The recording presents the whole event, but pre-fault time could be longer.

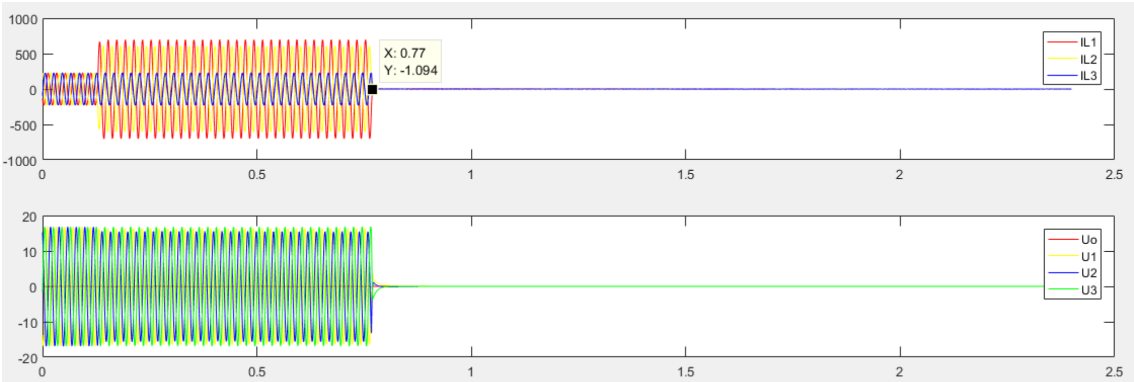

Figure 39. *Disturbance recording in feeder circuit breaker fault from busbar IED.*

5.2 Low voltage network simulations

This section presents smart meter measurements in DMS. RTDS simulation values are compared to DMS values and to calculated values from the low voltage network. Calculated values are from a neutral fault calculation Matlab tool that was presented in subsection 2.2.2. The comparison is done to verify measurements accuracy of the smart meter and that values are presented correctly in DMS. The Matlab tool is used for two reasons, the one reason is that students calculate fault voltages with the tool and the other reason is to detect that RTDS values are similar. Tool can calculate normal operation and neutral conductor faults in the low voltage network.

Table 8 below presents voltage magnitudes and angles in AMI system, which are calculated with the Matlab tool. The first column presents loading situations, in which the first load scenario includes three 2,5kW loads, the second load scenario has one 2,5kW load and two 1kW loads, and the third scenario has one 2,5kW load, one 1kW load and one 0,00005kW load. Scenarios have different size of loads at phases, because different loads cause unbalance in low voltage network. Voltage magnitudes and angles are collected to columns from different lengths of the low voltage network. The columns numerical values are distances between SS and customer. Distances are 100m, 500m and 1km from SS to customer.

Table 8. *Normal condition voltages calculated with the Matlab tool.*

Calculated values						
Length of AMKA	100m	Angle	500m	Angle	1km	Anlge
Phase L1 load 2,5kW	230,0	0	226,3	0	221,8	0
Phase L2 load 2,5kW	230,0	-120,0	226,3	-120,0	221,8	-120,0
Phase L3 load 2,5kW	230,0	120,0	226,3	120,0	221,8	120,0
UN	0	0	0	0	0	0
Phase L1 load 2,5kW	229,5	0	224,1	0	217,9	0
Phase L2 load 1 kW	230,8	-119,7	230,4	-119,9	229,6	-120,2
Phase L3 load 1 kW	230,7	120,5	229,9	121,0	228,8	121,5
UN	0,5	7,5	2,2	7,1	4,1	6,6
Phase L1 load 2,5 kW	229,3	0	223,4	0	216,2	0
Phase L2 load 1 kW	230,7	-119,9	229,8	-120,6	228,6	-121,5
Phase L3 load 1E-5 kW	231,4	120,7	233,2	121,0	235,5	121,4
UN	1,4	-23,0	3,3	-16,2	11,3	-23,4

Table 9 below presents smart meter measured values in normal load conditions from DMS. Values are collected from DMS customer point and table is similar as Table 8 earlier above except from neutral voltage values. Neutral voltage values are not listed in Table 9, because smart meter is not able to measure the neutral voltage. Reason for this is the metering setup. Phase angles are also presented in other form at Matlab tool than in DMS.

Table 9. *Smart meter values from DMS.*

DMS values						
Length of AMKA	100m	Angle	500m	Angle	1km	Angle
Phase L1 load 2,5kW	230,0	0	226,3	0	221,8	0
Phase L2 load 2,5kW	229,9	120,0	226,2	120,0	221,7	120,0
Phase L3 load 2,5kW	230,0	240,0	226,3	240,0	221,8	240,0
Phase L1 load 2,5kW	229,5	0	224,1	0	217,9	0
Phase L2 load 1 kW	230,8	120,0	230,4	121,0	229,6	120,0
Phase L3 load 1 kW	230,8	240,0	230,0	239,0	228,9	239,0
Phase L1 load 2,5 kW	229,3	0	223,2	0	216,2	0
Phase L2 load 1 kW	230,7	120,0	229,8	121,0	228,6	122,0
Phase L3 load 1E-5 kW	231,5	239,0	233,4	239,0	235,6	239,0

From Table 8 andTable 9, can be seen that the smart meter and the Matlab tool voltage magnitudes and angles are close to each others. This proves that iGW and SCADA forward data in correct scale to DMS as well as amplifier does not cause much error in between meter and RTDS in normal conditions.

Table 10 below presents calculated values in neutral conductor fault. The first column presents load conditions. Other columns present voltage magnitudes and angles in different wye point grounding conditions of the low voltage network. There are three different grounding conditions: 5Ω, 20Ω, and 100Ω. Network length is 500m and load conditions are same as in Table 8 and Table 9.

Table 10. *Calculated values in neutral fault.*

Calculated values, neutral fault on						
Length of AMKA	5ohm	Angle	20ohm	Angle	100ohm	Angle
Phase L1 load 2,5kW	226,3	0,0	226,3	0,0	226,3	0,0
Phase L2 load 2,5kW	226,3	-120,0	226,3	-120,0	226,3	-120,0
Phase L3 load 2,5kW	226,3	120,0	226,3	120,0	226,3	120,0
UN	0,0	0,0	0,0	0,0	0,0	0,0
Phase L1 load 2,5kW	204,3	0,0	179,7	0,0	159,8	0,0
Phase L2 load 1 kW	240,7	-124,3	255,5	-129,0	268,6	-132,4
Phase L3 load 1 kW	241,2	124,9	256,3	129,4	269,5	132,6
UN	22,4	-0,8	47,6	-0,7	67,8	-0,5
Phase L1 load 2,5 kW	195,3	0,0	157,0	0,0	125,0	0,0
Phase L2 load 1 kW	235,1	-132,3	250,5	-150,2	271,5	-169,8
Phase L3 load 1E-5 kW	260,4	121,1	300,6	117,9	339,6	109,8
UN	35,3	-24,3	81,3	-24,1	124,6	-24,0

Table 11 below presents the smart meter’s measured values that are read from DMS. Values are listed as in Table 10.

Table 11. *Smart meter measurements at DMS in neutral conductor fault.*

DMS values, neutral fault on						
Length of AMKA	5ohm	Angle	20ohm	Angle	100ohm	Angle
Phase L1 load 2,5kW	226,3	0	226,3	0	226,3	1
Phase L2 load 2,5kW	226,2	120	226,2	120	226,2	121
Phase L3 load 2,5kW	226,3	240	226,3	240	226,3	241
Phase L1 load 2,5kW	204,3	0	179,7	0	159,8	0
Phase L2 load 1 kW	240,6	124	255,4	129	267,6	120
Phase L3 load 1 kW	241,2	235	256,4	232	268,3	240
Phase L1 load 2,5 kW	195,3	0	157	0	125	0
Phase L2 load 1 kW	235,1	133	250,4	151	269,6	190
Phase L3 load 1E-5 kW	260,5	239	285,2	242	298,9	251

Table 10 and Table 11 present calculated and measured values in neutral fault of the low voltage network. As can be seen, measured values correspond the calculated values in neutral conductor fault. Only exceptions were with last loading scenario. In these simulations the measurement did not correspond to calculated values. Reason for different measurements are in the RTDS model. The RTDS model has limiters for measurements to prevent exceeding voltage limit of the amplifier, which caused that with high voltages the measurements were not presented correctly at DMS.

6. CONCLUTION

The objective of this thesis was to update and develop distribution automation laboratories for course Distribution Automation that is arranged at TUT. The course has two previous laboratory environments that needed to be updated.

The process began with defining the need for update and development potential. Parts from the previous laboratory implementations were not possible to use anymore, such as IEC 61850 MMS software, and some parts were needed to upgrade to new technologies, such as REX and PCs with Windows XP. Some new possibilities were interested to be implemented into laboratory environments. Also, an important aspect in environments was interesting and informative content.

With these backgrounds the laboratories were improved. IED laboratory introduces new REF615 protection IEDs with extended features to present functionality of IEDs for students. In substation automation laboratory, IEDs are connected to RTDS with open and close command inputs and status signal outputs. Blocking signal is implemented with Ethernet connection.

The low voltage automation laboratory is updated with new SCADA and DMS, remote communication unit, and the smart meter. The laboratory environment extends the first laboratory by using the same network structure. In the second laboratory, the first laboratory environment's substation is possible to control from SCADA environment. The substation communication is implemented with RTDS-iGW-SCADA link. In this way, students get idea from communication structure of substation automation. In the low voltage network, the smart meter's values are transferred to SCADA through data concentrator. Typically, smart meter data is not send to SCADA, but in the laboratory environment this was made, because ease of build and the system is easily scalable, because the minimum amount of devices. The network topology and state is presented on DMS. From DMS, students are able to control the primary substation and observe customer smart meter measurements.

The laboratories are tested with protection tests and measurement tests. The tests are similar to students' laboratory exercises. The substation automation laboratory operation was detected with different fault scenarios and operation conditions. The low voltage laboratory was tested with measurements where values were calculated with a Matlab tool at first and then values were compared to RTDS simulation values that were read from DMS.

The laboratories present good overall view from distribution automation. The first laboratory presents IEDs and protection principles. The first laboratory environment is now more informative than the previous one, because students have possibility to control circuit breakers and read events from IEDs screen. In the low voltage automation laboratory, SCADA and DMS systems are presented. In the previous implementation of the low voltage automation laboratory, the role of SCADA was not as clear as in new implementation. It is important that DMS and SCADA are well presented, because the systems are important part of the course.

The future development needs are in the low voltage automation laboratory. The system could be extended by adding more functionalities to the substation. In presented implementation of the second laboratory, the functionality of substation does not present functionality of real substation. Also, fault service functions could be added to the low voltage automation laboratory, which are implemented in the simulation model. A fault detection and clearance would be good extension. Fault indications and remote controllable disconnectors would be great to add to simulation model, because those devices are key part of distribution automation development in Finnish distribution companies. IED laboratory could be updated with better earth fault protection functions, but this is not necessary, because laboratory teaches the fundamentals from protection.

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