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INTEGRATING LOW VOLTAGE DISTRIBUTION SYSTEMS TO DISTRIBUTION AUTOMATION

Master's thesis for the degree of Master of Science in Technology submitted for inspection in Vaasa, 30 May 2012.

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PREFACE

This Master's Thesis is a part of Finnish Smart Grids and Energy Markets (SGEM) research program, which is carried out 2009 – 2014. The SGEM consortium is managed by Cleen Ltd., which is the strategic research center for the Cluster for Environment and Energy. Main funding partners for the SGEM program is Tekes. This study is a part of the Task 6.1 at the 2nd funding period and it involves the next generation ICT-solutions for network management.

The study has been prepared at the Faculty of Technology at the University of Vaasa with the assistance of my supervisor professor and dean of Faculty of Technology Erkki Antila as well as my instructor professor Kimmo Kauhaniemi. I thank you both for the valuable comments and feedback during the work. Further I thank all my colleagues for the pleasant team spirit in the working room.

Special thanks to my precious team at home. Mother Tarja and father Jaakko; you took so good care of the children many times. My husband Heikki; thanks for enabling this in practice.

My lovely children Olli, Paula, Miska and Mitro; hopefully my working with this Thesis strengthened your passion to learn and to work for new things, as I did.

Vaasa, Finland, May 2012

Katja Sirviö

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SYMBOLS AND ACRONYMS

Symbols

d_c	Relative steady-state voltage change
f	Frequency [Hz]
I_k	Short circuit current [A]
I_n	Nominal current [A]
P_{lt}	Long-time disturbance index
P_{st}	Short-time disturbance index
S_k	Short circuit apparent power [VA]
S_n	Nominal apparent power [VA]
t	Time [s]
U_l	Phase voltage [V]
U_n	Nominal voltage [V]

Acronyms and abbreviations

AC	Alternating Current
ACB	Air Circuit Breaker
AI	Analogue Input
AMR	Automated Meter Reading
AMI	Automated Meter reading Infrastructure
ANSI	American National Standards Institute
AVR	Automatic Voltage Regulator
CAMC	Central Autonomous Management Controller
CB	Circuit Breaker
CDC	Cable Distribution Cabinet
CHP	Combined Heat and Power
CIS	Customer Information System
CO_2	Carbon Dioxide
CSS	Compact Secondary Substation
DA	Distribution Automation

DC	Direct Current
DEM	Distribution Energy Management
DER	Distributed Energy Resource
DG	Distributed Generation
DLC	Distribution Line Carrier
DMS	Distribution Management System
DNP	Distributed Network Protocol
DO	Digital Output
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution System Operator
EMC	Electro Magnetic Compatibility
EN	European Standards
EPA	Enhanced performance Architecture
ES	Energy Storage
EU	European Union
EV	Electric Vehicle
FA	Feeder Automation
FDIR	Fault Detection Isolation and Restoration
FPI	Fault Passed Indicator
FRT	Fault Ride Through
GIS	Geographical Information System
GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
GPRS	General Packet Radio Service
GSM	Global System for Mobile communications
GSSE	Generic Substation State Event
HAS	Home Automation System
HGW	Home Gateway
HMI	Human Machine Interface
HSR	High-Speed automatic Reclosing
I/O	Input / Output
IEC	International Electrotechnical Commission

IED	Intelligent Electronic Device
ISO	International Organization for Standardization
LC	Load Controller
LOM	Loss-Of-Mains
LTE	Long Term Evolution
LV	Low Voltage
LVDA	Low Voltage Distribution Automation
MC	Micro-source Controller
MDM	Metering Data Management
MGCC	Microgrid Central Controller
MIS	Material Information System
MMI	Man Machine Interface
MMS	Microgrid Management System
MTU	Master terminal Unit
MV	Medium Voltage
N	Neutral
NCC	Network Control Centre
NCS	Network Control System
NIS	Network Information System
NTP	Network Time Protocol
OLTC	On-Line Tap Changer
OSI	Open System Interconnection
PD	Protection Device
PE	Protective Earth
PEN	Protective Earth and Neutral
PLC	Programmable Logic Controller
PV	Photo Voltaic
P2P	Point-To-Point
RES	Renewable Energy Resource
ROCOF	Rate Of Change Of Frequency
RS	Recommended Standard
RTU	Remote Terminal Unit
SA	Substation Automation

SCADA	Supervisory Control and Data Acquisition
SGS	Smart Grid Switch
SMS	Short Message Services
SS	Static Switch
TIA/EIA	Telecommunications Industry Association/Electronic Industries Alliance
THD	Total Harmonic Distortion
TSO	Transmission System Operator
UCA	Utility Communications Architecture
UPS	Uninterruptable Power Systems
UTC	Coordinated Universal Time
VAR	Volt Ampere Reactive
WLAN	Wireless Local Area Network
VPP	Virtual Power Plant
V2H	Vehicle-To-Home
V2G	Vehicle-To-Grid
2G	Second Generation
3G	Third Generation
4G	Fourth Generation

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ABSTRACT

The aim of this thesis is to define and study the key elements and the main characteristics of the integration of the low voltage (LV) distribution systems to distribution automation (DA). The key elements are defined by studying the development of essential systems in LV distribution networks as well as by studying the development of the networks by way of evolution phases. The key elements and the main characteristics of the integration to DA are illustrated by a certain model of a LV distribution network under its development.

For a start DA is reviewed by generally used functions and by technologies. The review includes the data and the information systems and in addition the communication networks are studied generally. Thereafter the main elements of LV distribution networks are presented and their evolution visions are introduced. The main elements comprises of the distribution network, distributed generation, smart energy metering, electric vehicles and energy storages.

The approach to the integration is the evolution of LV distribution networks, so four main evolution phases are introduced; traditional, boom of distributed generation, microgrid and intelligent microgrid. The evolution phases bases on general research publications and visions of Smart Grids. Management architectures for the networks are presented. Also requirements for communication are evaluated by studying the number of nodes, capacity requirements for transferred data types and fault and event frequencies.

In order to define a proposal for integrating LV distribution networks to DA, the management architectures and the studied requirements are compared to produce functions for DA. As a result, the proposal is presented based on the studied architectures and requirements. In addition considerable issues are introduced relating to the functions in devices or sub-systems, which are needed for DA applications. This thesis indicates the need for further studies, such as: Which are the desired DA functions to be extended to LV distribution networks? Which device or system should offer the desired functions? How well the potential protocols using some media type serves the functions?

KEYWORDS: Distribution Automation, Low Voltage Distribution System, Distributed Generation, Microgrid, Communication

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TIIVISTELMÄ

Tämän työn tarkoituksena on määritellä ja tutkia tärkeimpiä asioita pienjännitejakeluverkkojen (pj-jakeluverkkojen) integroimisessa sähkönjakeluautomaatioon. Nämä avainasiat määritellään tutkimalla pj-jakeluverkoissa olevia järjestelmiä ja niiden kehittymistä sekä verkkojen evoluutiota kehitysvaiheittain. Integroinnin keskeiset tekijät ja niiden tärkeimmät ominaisuudet esitetään pj-jakeluverkkomallin avulla.

Sähkönjakeluautomaatioon sisältyvät päätoiminnot on esitelty aluksi. Lisäksi toimintoihin käytetyt tekniikat, tieto- ja informaatiojärjestelmät sekä tietoliikenneverkot siihen liittyvineen järjestelmineen on kuvattu yleisellä tasolla. Seuraavaksi pj-jakeluverkkojen peruselementit sekä niiden kehitysvisiot on esitetty. Peruselementit ovat jakeluverkko, hajautettu tuotanto, älykäs energian mittaus, sähköautot ja energiavarastot.

Pienjännitejakeluverkkojen kehittymistä kohti älykästä sähköverkkoa tutkittiin tässä työssä neljän kehitysvaiheen avulla, jotka pohjautuvat tutkimusraportteihin ja yleisiin visioihin älykkäistä sähköverkoista. Kehitysvaiheet ovat perinteinen (traditional), hajautetun energiantuotannon voimakas kasvu (boom of the distributed generation), mikroverkko (microgrid) ja älykäs mikroverkko (intelligent microgrid). Lisäksi arkkitehtuureja on esitetty verkon hallintaa varten, ja tämän perusteella tiedonsiirrolle asetettavia vaatimuksia arvioitiin kaupunki-, taajama- ja haja-asutusalueella. Vaatimuksia tiedonsiirrolle asettaa fyysisten rajapintojen lukumäärä, siirrettävän tiedon kapasiteettivaatimukset sekä vika- ja tapahtumataajuudet.

Ottaen huomioon tarvittavat toiminnot sähkönjakeluautomaatiossa, lopputuloksena ehdotetaan tutkittua arkkitehtuuria sovellettavan pj-jakeluverkkojen hallitsemiseen ja pj-jakelujärjestelmien integroimiseen sähkönjakeluautomaatioon. Lisäksi esitetään selvitettäviä asioita, joita ovat esimerkiksi: Mitkä ovat toiminnot, jotka todella halutaan pj-jakeluverkosta käytettävän ylemmän tason jakeluautomaation sovelluksissa verkkojen eri kehitysvaiheissa? Mikä laite tai järjestelmä olisi siihen sopivin? Mitkä ovat toteuttamiskelpoiset protokollat käyttäen järkevää tiedonsiirtoyhteyttä, jotka pystyisivät vastaamaan haluttuihin toimintoihin?

AVAINSANAT: Sähkönjakelun automaatio, Pienjännitejakelujärjestelmä, Hajautettu tuotanto, Microgrid, Tiedonsiirto

1 INTRODUCTION

Energy consumption globally is estimated to double by year 2050 if current practices continue. At present the global energy system is mainly based on fossil energy resources, which causes environmental impacts in power production. In addition power distribution is hierarchical from centralized generation to end customers, so electrical power is transferred from a distance and voltage is transformed several times to suitable levels before consumption points, causing losses of energy. Intelligent electricity distribution networks are one of the main conditions for reducing carbon dioxide (CO_2) emissions by utilizing local renewable energy resources to increase efficiency in energy distribution.

The European Union (EU) set demanding climate and energy targets to be met by 2020, known as the "20-20-20" targets, which became law in June 2009. In the EU climate and energy package three main requirements are defined as follows: 20 % reduction (below 1990 levels) of greenhouse gas emissions, 20 % energy consumption utilized from renewable energy resources (RES) and 20 % reduction in primary energy use by improved energy efficiency. The energy strategy is ambitious for year 2020 and intended to be continued beyond 2020 to reduce emissions strongly. The Energy Roadmap 2050 highlights energy efficiency and the penetration of RES as having significant roles in future scenarios, because investments made today have a great impact on achieving feasible energy prices in future.

Power outages and condition of electricity distribution networks have been highlighted in recent years in context to storms. Electricity distribution companies are obligated to compensate to the customers the outage time caused by, for example, large thunderstorms. In addition, penalties for non-delivered energy are regulated in Finland to affect allowed incomes and profit for the companies. On the other hand the regulations have incentives for power quality improvement permitting higher profit by lower outage costs. Distribution networks in Finland are aging and therefore reinvestments become topical.

In order that the incoming boom of renewable energy generation will succeed, the development of a future energy infrastructure is required to focus on upgrading the existing electricity distribution grids to be operated more intelligently as well as improving the data availability by measurements of energy and quality of electricity. Upgraded distribution networks should secure safe and reliable distribution of electricity, energy savings and efficient use of energy as well as advanced energy markets. Smart Grids are an essential concept which is introduced being to respond to future needs. Smart Grids are described as an active intelligent electricity network where different actors are interlinked with two-way communications; for example new functions and functionalities for consumers and energy suppliers, like real time control of energy are achieved by smart energy metering and monitoring systems.

The European Technology Platform (ETP) SmartGrids vision for the Europe's electricity networks of 2020 and beyond is (EU 2006: 4):

- Flexible: fulfilling customers' needs whilst responding to the changes and challenges ahead;
- Accessible: granting connection access to all network users, particularly for renewable power sources and high efficiency local generation with zero or low carbon emissions;
- Reliable: assuring and improving security and quality of supply, consistent with the demands of the digital age with resilience to hazards and uncertainties;
- Economic: providing best value through innovation, efficient energy management and 'level playing field' competition and regulation.

SmartGrids are defined as follows (EU 2010: 6):

> "A SmartGrid is an electricity network that can cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety."

The main difference between grids today and SmartGrids is the grid's capability to handle more complexity than today in an efficient and effective way. Innovative products and services together with intelligent monitoring, control, communication, and self-healing technologies are exploited in SmartGrids. (EU 2010: 6)

The controllability of distribution networks or distribution automation (DA) has been generally applied down to primary substations and medium voltage (MV) networks. DA is utilized for improving network performance and reliability in normal operation and in fault situations. Functions to be applied in normal operation are, for example, load flow and fault calculations, voltage and reactive power control and loss minimization. In fault situations the most profitable action is to applied outage management and feeder automation by making the fault location and supply restoration effectively. DA system is composed mainly of a network control system or SCADA (Supervisory Control and Data Acquisition), a substation automation system and a voltage regulating system. At present the increasing number of automated meter reading infrastructure (AMI) and monitoring devices in secondary substations gives a chance to extend controllability and automation down to low voltage (LV) distribution networks. In future the management of LV networks will become challenging, because of the penetration of distributed generation, the increase of electric vehicles (EVs) and the requirements for demand response (DR). In order for LV distribution networks to interact with existing DA systems, like with distribution management system (DMS), communications between different systems have to be established and developed as well as the equipment involved. Local intelligence like adaptive protection devices as well as possibilities for real time communication are under pressure to evolve alongside them.

The development of LV distribution networks towards active distribution networks or Smart Grids is introduced with two concepts, which are microgrids and virtual power plants (VPPs). The definition of a microgrid is (EU 2006: 27):

> "Microgrids are generally defined as low voltage networks with DG sources, together with local storage devices and controllable loads (e.g. water heaters and air conditioning). They have a total installed capacity in the range of between a few hundred kilowatts and a couple of megawatts. The unique feature of microgrids is that, although they operate mostly connected to the distribution network, they can be automatically transferred to islanded mode, in case of faults in the upstream network and can be resynchronised after restoration of the upstream network voltage.
>
> Within the main grid, a microgrid can be regarded as a controlled entity which can be operated as a single aggregated load or generator and, given attractive remuneration, as a small source of power or as ancillary services supporting the network."

The second way to realize an active distribution network is VPPs or virtual utilities or virtual electricity market. Virtual utilities are described as (EU 2006: 27):

> "Virtual utilities (or virtual electricity market) adopt the structure of the internet-like model and its information and trading capability, rather than any hardware. Power is purchased and delivered to agreed points or nodes. Its source, whether a conventional generator, RES or from energy storage is determined by the supplier. The system is enabled by modern information technology, advanced power electronic components and efficient storage."

VPPs are not studied in this thesis, because they are intended mostly for intelligent energy trading.

The aim of this thesis is to define and study the key elements and the main characteristics of the integration of the low voltage distribution systems to distribution automation (DA). Therefore the key elements of essential systems in LV distribution networks as well as the evolution of LV distribution networks should be studied.

The evolution of traditional LV distribution networks towards intelligent distribution networks or microgrids can be considered by way of the increment of modern functionalities in the LV distribution network management, which are enabled by enhanced main elements. Microgrids are a successful concept for an active network aiming to self-sufficiency in energy and to independent operations in normal and fault situations. The development of the main elements is significantly related to the distribution grid, distributed generation (DG), smart metering or automated meter reading (AMR), EVs and energy storages (ESs) and suitable communications. In this thesis four evolution phases are introduced with related functionalities for LV distribution networks developing towards intelligent microgrids. The starting point of the introduced phases is based on EU's "Microgrid evolution roadmap to EU" as well as general development visions of the main elements.

Different stages of evolution in LV distribution networks bear specific functionalities which bring differences to the requirements of communication systems and intelligence of devices. In order to obtain desired functionalities by remote control and operation of devices and systems, the requirements for communications are outlined. A study of suitable communication system, media and protocols, based on communications generally used in DA at present, is made for the evolution phases. The study highlights wireless communication, because it is well desired to be exploited for systems in LV distribution, especially in public wireless networks like global system for mobile communications (GSM). The feasibility study for data transfer is made by comparing characteristics (speed, data amount etc.) with the requirements based on the defined operational functionalities of LV distribution network in the evolution phases in the areas of different LV distribution networks.

The defined evolution phases in this thesis can be utilized as a draft which guides the designer to pick up different operational requirements for various sub systems of LV distribution network under its development. The defined requirements for communication in each evolution phase can be utilized, for example, to the development of a specific LV distribution network for ensuring the ability to perform the main functions interlinked with DA and for taking into consideration the pending functionalities of microgrids. As a result, this thesis outlines some suitable communication media and protocols for integrating LV distribution networks to DA to be studied more in future. In addition this thesis shows the requirements arising from the DA functions to be extended to LV distribution and the device offering the function to be considerable.

The Chapter 2 introduces the general functions and technologies of DA. In the Chapter 3 basic elements of low voltage distribution are defined and visions of evolution are presented for outlining evolution phases of low voltage distribution in the Chapter 4. Integrating issues including requirements for communication system as well as communication interfaces in the related evolution steps are outlined in the Chapter 5.

2 DISTRIBUTION AUTOMATION

Control and automation of electricity networks play the key role in electricity business environment for different enterprises of production, supply, bulk transmission, delivery or distribution and metering. DA generally covers functions for safety and protection as well as operation and control as well it offers functions for business and asset management. Companies implementing DA achieve reliability improvement, operating efficiency and extend of asset life amongst other benefits.

Automation for operations in entire distribution system is referred to the DA concept. DA concept is an umbrella term covering the complete range of functions from protection to network control system (NCS), generally called SCADA, and applications applied. Essential systems in DA are NCS, substation automation (SA), feeder automation (FA) and AMR supported with distribution management system (DMS). (Northgote-Green et al. 2007: 11–12).

Traditionally electricity distribution is handled by primary processes and management processes and therefore DA is applied within a structured control hierarchy with different layers of the network as the Figure 1 presents. The processes can be divided up into horizontal levels by their locations in the distribution network. The levels are the LV network (or consumer), MV network (or distribution), bay, substation, control (or network) and enterprise (or utility) level. (Northgote-Green et al. 2007: 10; Antila 2006: 24–25).

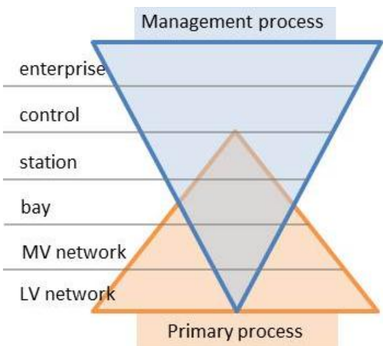

Figure 1. The electricity distribution process and its management process. (Antila et al. 2006: 24–25).

The novel approach to DA is composed vertically as the Figure 2 presents. The main operations in distribution network management are specified by the process levels. The processes are management sectors for distribution network safety and protection, control and operation, asset and business, which mean that the new concept provides the managing means for the distribution system on market terms. (Antila et al. 2006: 24–25; Antila et al. 2009: 8).

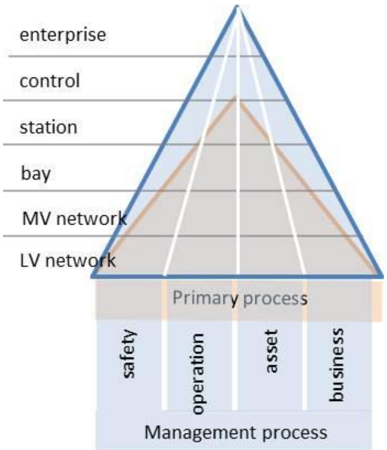

Figure 2. The traditional and the modern model of the DA concept management (Adapted from Northgote-Green et al. 2007: 11–12; Antila et al. 2006: 24–25; Antila et al. 2009: 8).

Communications is the key enabler for the modern DA concept. Different devices, systems, maintenance staff and business partners connected together in real-time call for open communication and transparent data change in every level horizontally and vertically. For improving management processes, the communications can be examined in different aspects like concepts or applications so far as to a single device in the levels of the power distribution. The three-dimensional model to access data everywhere in a power distribution system is presented in the Figure 3 (Antila et al. 2009: 7–8). For example the figure illustrates the information flow to the consumer about a fault in the MV network, which is traditionally coming from a single protective relay up to control and management system down to the consumer. In future it would be sustainable to develop open information flow in horizontal and vertical levels to be exploited in different levels of power distribution, aspects and management processes. Today for example the AMR is the best accessible system, where data of LV distribution could be exploited.

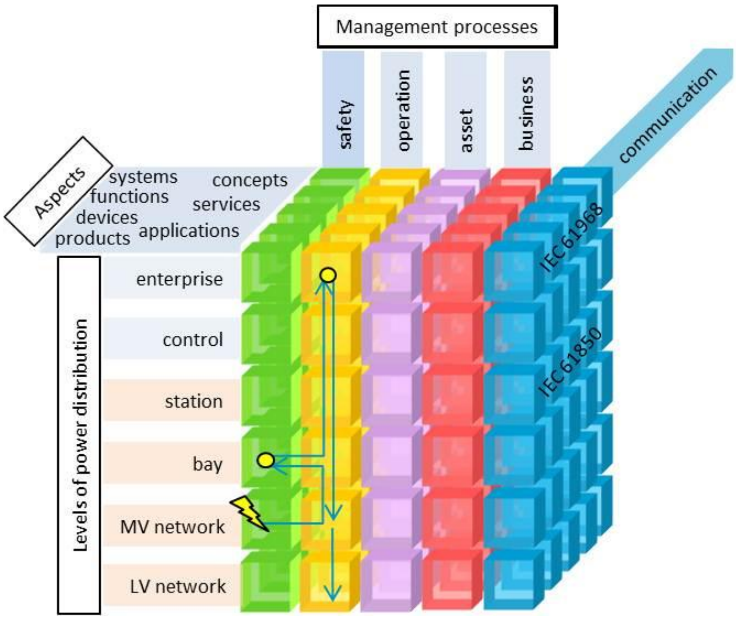

Figure 3. 3D model for data access in electricity distribution system. (Antila et al. 2006: 24–25; Antila et al. 2009: 8).

2.1 Functions

Traditionally DA refers to MV distribution networks and in practice DA is realized by functions in different levels of electricity distribution system like in control rooms, distribution network and substations. The main functionalities in MV distribution network management are outage management, network operation (monitoring and control), remote control of substations, substation automation and supporting functions. (ABB 2000: 403).

Functions can be dedicated into the foregoing management processes and identified to the levels of power distribution down to the functionality of the actuating device. The Figure 4 describes the main functions in safety and protection management as well as operation and control management in the levels of power distribution.

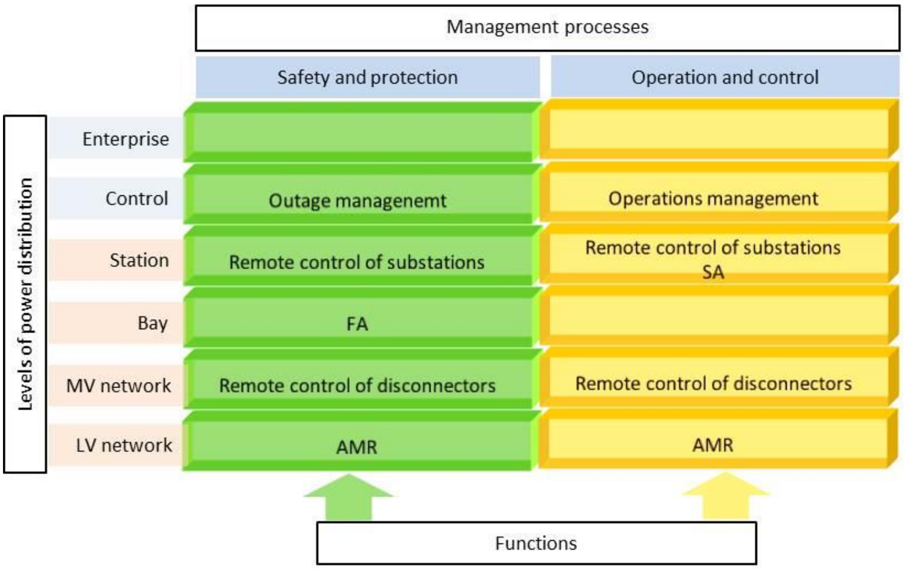

Figure 4. Main functionalities in safety and protection management as well as operation and control management in the levels of power distribution.

2.1.1 Network operations

Operation and control in distribution networks comprise of functions in normal state based on monitoring or controlling important nodes. Network monitoring is mostly related to functions of network normal operation and functions exploitable for planning and maintenance. Network status or network condition is monitored at important nodes *with the following functions*:

- load flow calculation
- fault calculation
- maintenance of network architecture
- maintenance of switchings
- network planning and calculation (fault currents, set values of protective relays)
- load estimation and prediction
- quality of electricity
- condition of network components
- management of maintenance activities

Load flow calculation provides steady-state solutions for circuit configurations and load levels. Load levels are estimated with the basis of “as much real-time data as possible” available from SCADA. The load calibration process for load estimation consists of three phases; static load calibration, topological load calibration and representation of network loading. Static load calibration use static information like load profiles, number of customers and season to calculate active and reactive power consumption. Topological load calibration uses the static results of power consumption, the latest measurement values and the current topology of the network to determine the dynamic values for active and reactive power consumption. Finally, the network loading state is represented with losses included. (Northgote-Green et al. 2007: 61–63).

Fault calculations are made for balanced or symmetrical – three phase faults and asymmetric faults. The symmetrical short circuit analysis simulates a fault on every bus in the electrical power system. Unbalanced or asymmetric short circuit analysis calculates line-to-line short circuit with and without earth connection as well as line-to-earth short circuit. With this method, the currents in each line are found by superposing the currents of three symmetrical components. Fault calculation is used in a DMS for checking limits of breaker ratings, which determine whether a CB operates above its rating and thus an alarm of unsatisfactory operating state can be sent to the operator. (Northgote-Green et al. 2007: 63–65).

The network control operations can be facilitated with automation, because the controlled *nodes afford functions like*:

- Remote control of disconnectors
- Control of voltage
- Control and compensation of reactive power
- Optimizing of system operation
- Planning of switchings
- Checking and adaptation of protection
- Logbook of controls and disturbances in the network

Remote control of disconnectors speeds up the switching states, which have a great benefit in fault situations. In network normal operation remotely operated disconnectors quickens the normal maintenance and repair work. (ABB 2000: 404).

Voltage control is designed for the control of on-line tap changers (OLTCs) associated with transformers at primary substations and line voltage regulators. The function calculates set points of voltage or tap settings at the OLTC to reduce overall system load. Control strategy can be for example the *target voltage reduction* which reduces the system load so that lowest permissible voltage level is achieved. (Northgote-Green et al. 2007: 67–68).

Reactive power control or VoltAmpere Reactive (VAR) control is for the of MV capacitor banks which are located at primary substations and on MV feeders. Configurations for capacitors, which reduce reactive power flows into the MV system, are determined under limit conditions of voltage and power factor. Operating state regarding to VAR compensation is determined by comparing the actual power factor of total service area, which is measured by SCADA, with the target power factor. (Northgote-Green et al. 2007: 66–67).

Loss minimization applications provide ability to identify feasible switching changes for loss reduction, to calculate the necessary reallocation of load among feeders, to verify proposed optimized system condition within operating limits (capacity and voltage), to run within specific characteristics and to restrict the optimization to use remotely controllable switches only. (Northgote-Green et al. 2007: 66).

All these advanced functions or applications presented are entirely dependent on data availability and its quality. Outage management and basic switching plans depend highly on correct network topology. Advanced applications can be divided into two categories, which are topology based and parameter based applications as presented in the Table 1. Topology based applications operate satisfactory with topology data only as for parameter based require network parameter data in addition to topology data.

Table 1. Categories of applications. (Northgote-Green et al. 2007: 70).

Application	Topology-based	Parameter-based
Network coloring	X	
Switch planner	X	X
FLIR (Outage management)	X	X
Operator load flow		X
Fult current analysis		X
Volt/VAR control		X
Loss min. / optimal reconfiguration		X

2.1.2 Outage management

Outage management is intended for returning the normal state of an electricity distribution network from an emergency state. The process of outage management consists of three phases which are *outage alert, fault location* as well as *fault isolation and supply restoration*. A detailed model of distribution network, usually geographic information system (GIS) is the core of an outage management system. Utilities with limited amount of real-time control use trouble call approach, whereas utilities with good real-time systems use advanced application based approach by means of direct measurements from automated devices. (Northgote-Green et al. 2007: 50).

In *trouble call based system* fault alert is signified by the first trouble call from a customer and confirmed once additional calls are received. The determination of fault location proceeds by inferring and verification. The process is often called the outage engine and the method relies on a radial network model. In LV networks various hybrid assignment methods for example postal code in addition to GIS have been used to check early mains records. Location of a fault is determined by an operated protection device or open conductor and the de-energized network. Verification of an outage is confirmed by the field crew manually or by SCADA remotely. After verification the outage engine analyses the switching events and other connectivity changes (phased supply restoration). Supply restoration is often partial where normally open points or alternate feeds are used to feed the healthy parts. When manual actions are completed with the confirmation from the field, the operator enters connectivity changes into the DMS. The outage engine keeps track on changes and the event. (Northgote-Green et al. 2007: 52–56).

Advanced application-based outage management is able to benefit the use of SCADA with real time input from data-collection devices. The information from the measurement devices is delivered to the topology engine within the real-time system network model and the engine determines fault location. Trouble calls add additional information after the event for highly automated network. Faults are generally localized by circuit breakers (CB) installed in primary substations. The implementation of FA by means of fault passed indicators (FPI) associating with remotely controlled line switches or by means of communicating FPIs improves the resolution to indicate fault locations. Fault isolation algorithms determine the necessary switching sequence for isolation and present the suggested switching plans for operator approval and execution. The feasibility of supplying load from as alternate feed is tested by *load flow calculations*. Open switches are identified, which can be closed to restore supply to the isolated network. Most systems present to the operator a recommended sequence for approval and implementation to be confirmed step by step. (Northgote-Green et al. 2007: 57–59).

2.1.3 Remote control of substations and substation automation

The majority of data in a power system is acquired from substations by means of SCADA system. Traditionally a SCADA system is built up by installing a remote terminal unit (RTU) to the substation which is connected to protection relays and auxiliary contacts of switches as well as to the central control system as a communications interface. SCADA offers functions like data acquisition, data processing, remote control, alarm processing, historical data, graphical human machine interface (HMI), emergency control switching and load planning for demand side management (DSM).

Remote control of substations by the SCADA system enables remote control of breakers, disconnectors and tap changers as well as different type of measurements of busbars and feeders. Remote controlled substations and systems create a real-time interface to important nodes in electricity distribution. At present a major target for development is integrating to other systems as well as expanding to exploit data from new subsystems like from local meteorological stations. In future remote controlled systems will increasingly be connected to different subsystems like FA, disconnectors in the network and local control as well as load control system. (ABB 2000: 405).

SA composes of remote as well as local monitoring and control of the substations, and in addition communication between the local automation system and the network control centre. Local or remote control system can send commands such as control commands, set values and parameter data to devices as well as messages for time synchronization. (Northgote-Green et al. 2007: 73).

Local control and monitoring includes functionalities for example:

- voltage control, event- and alarm management,
- transfer sequences of busbars, interlockings and centralized load shedding,
- condition monitoring,
- relay protection,
- automatic reclosing of feeders and
- synchronization of substation clock with overall system time.

Plenty of data is available from substations for utilization in local and remote control systems, which are provided by protective relays, control devices and alarm centres as follows:

- Time stamped events
- Measured electrical quantities
- Position indications of CBs and disconnectors
- Alarms
- Digital input values
- Operation counting
- Disturbance records
- Set values and parameters of devices (Northgote-Green et al. 2007: 73).

Local monitoring and control of a substation is provided with HMI. The HMI collects data from intelligent electronic devices (IEDs) for distribution and archiving purposes. Further a HMI can act as a communication gateway, which basic functionalities are protocol conversions (for example Modbus to IEC 60870-5-101/104), filtering too frequent changes, combining signals as well as transferring of files and disturbance records. Centralized interlocking functions of feeders provide continuous power supply, which is achieved with automatic change over transfer functions from a main feeder to a standby feeder as fast as possible and in addition load shedding by switching off non-essential loads. (Adine 2010: 47–48).

The relay protection in a SA system initiates corrective actions at malfunctions of network operation. Currently IEDs provide more functionality, performance and scalability than traditional protection relays. In addition to a large number of different protection functions IEDs provide control, measurement, power quality monitoring and condition monitoring for distribution network and its components. Control functions of an IED include position indications and control commands of switching devices like CBs and disconnectors. Position information and control signals are transmitted over station bus and they can be used for inter-bay interlocking schemes. Measurements provided an IED are for example phase currents, neutral current(s), phase-to-phase or phase-to-earth voltages, residual voltage, frequency and power factor. (Adine 2010: 48–49).

2.1.4 Feeder automation

The main purpose of the fault management is to locate and isolate a fault as well as restore the supply to unfaulted part of distribution network as quickly as possible. A fault detection isolation and restoration (FDIR) application running at the substation or control centre manages the fault situations. A fault is usually detected by an open function of a CB of the faulted feeder. A temporary fault is cleared by auto reclosing function of a protection relay. The fault location is traditionally defined by trial switchings and dividing & conquering. (Adine 2010: 50).

In a fault situation of a MV feeder the information of the fault is available based on the operations of protection relay and CB. The data including a detailed model of the faulted feeder and conclusions of proposed fault locations is transferred to SCADA. Thereafter possible fault locations are defined in DMS by using information about fault detectors, terrain conditions and weather amongst others. Switchings for locating and isolating the fault are proposed and thereafter the operator makes the actual decisions and performs the switchings remotely using SCADA system or manually executed by staff working on the network. (Adine 2010: 50–51).

Remote controlled disconnectors speed up the finding of the fault location. A fault detector or a FPI indicates whether the fault current has passed or not and therefore speeds up the reasoning of the fault location. Automatic sectionalizers isolate a faulted part of the distribution network using the autoreclosing functions of CBs. Remote controlled disconnectors with fault detectors can be used for automatic fault isolation. (Adine 2010: 50).

2.1.5 Automated meter reading

The main purpose of an AMR system is to provide energy consumption data of customers to utility for billing and balance purposes and in addition load control for some customers. Traditionally AMR systems have been separate, but at present implementations of advanced AMR systems called AMI are changing the basic energy measurement towards multiple advanced functions to be utilized. A distribution system operator (DSO) can utilize AMI for supporting network operation, network planning, asset management, power quality monitoring, customer service, load control and for traditional billing and load settlement. AMI supporting network operation can include functions for automatic fault indication, isolation and location as well as precise data of voltage and load. For supporting asset management, AMI provides for example exact load profiles for network calculations. Power quality monitoring by AMI includes data of interruptions and voltage characteristics. (Adine 2010: 50).

2.2 Network control system

Control of different networks is mainly implemented with a dedicated NCS, which is generally called the SCADA system. SCADA is the acronym for Supervisory Control and Data Acquisition and generally these systems are intended for monitoring and controlling a plant or equipment applied in industries such as telecommunications, water and waste control, energy, oil and gas refining and transportation. A SCADA system gathers and transfers information, alerts, carries out necessary analysis and control, determines critical functions, and displays the information in an illustrative fashion. These systems can be relatively simple like control of environmental conditions in a small office building or system can be very complex such as control of a nuclear power plant.

In electricity distribution networks SCADA gathers information from various points to network control centre (NCC) for remote control and monitoring purposes as well as for further analysis to the DMS. SCADA also send commands to control devices in the network, communicates with RTUs, remote controlled switches and IEDs. The entity of DA system is outlined in the Figure 5 where communication links are presented between the NCC, RTUs, customer automation (energy measurement and load control) and information systems. (Adine 2010: 40; Sirviö 2011: 16).

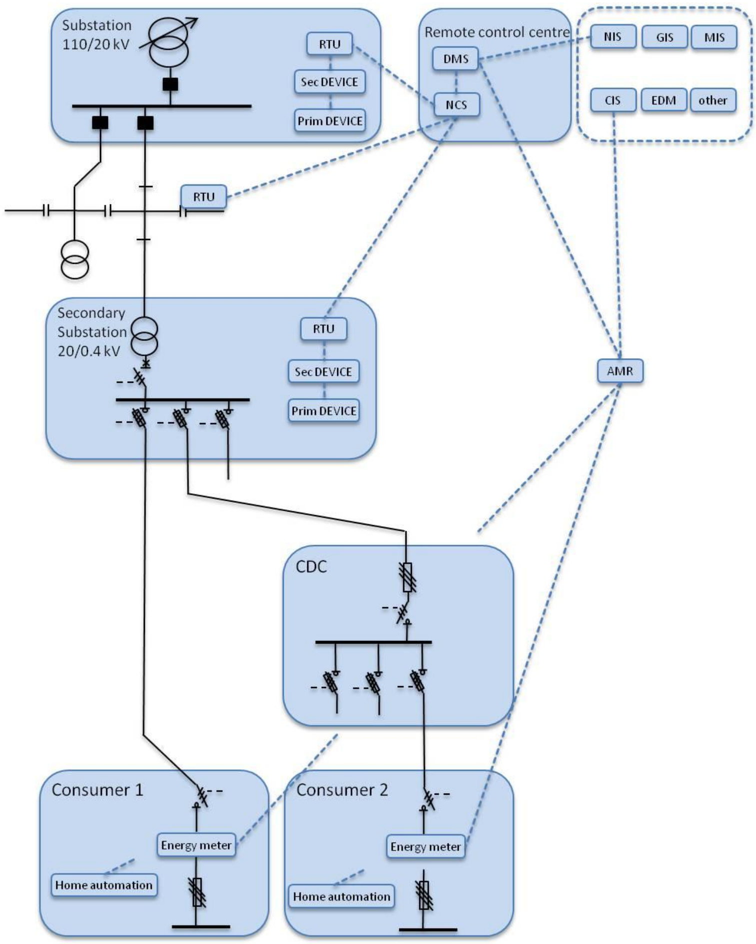

Figure 5. The distribution automation system entity (Adapted from Lakervi & Partanen 2008: 233; Sirviö 2011: 16).

2.2.1 Architecture

The control architecture of electricity network can be found as several different types today, because the architecture applied depends highly on the age and the size of the network. General lifetimes for equipment in control systems are quite long as presented in the Table 2 . Because of long life times of equipment types, several technologies can be still found for control systems as the Figure 6 illustrates. (ABB 2010c: 36)

Table 2. Lifetimes for equipment in the control system of the electricity distribution. (Adapted from ABB 2010c: 36).

Equipment	Life cycle [years]
Network control center	6-10
Operator workplaces	
SCADA servers	
Front-ends	
Remote communication	6-20
Communication equipme	
Substation level	7-10
Substation HSI	
Substation gateway	
Bay level	15-25
Secondary equipment	
P & C IEDs	
Primary equipment	30-40
Switchgear	
Transformers	

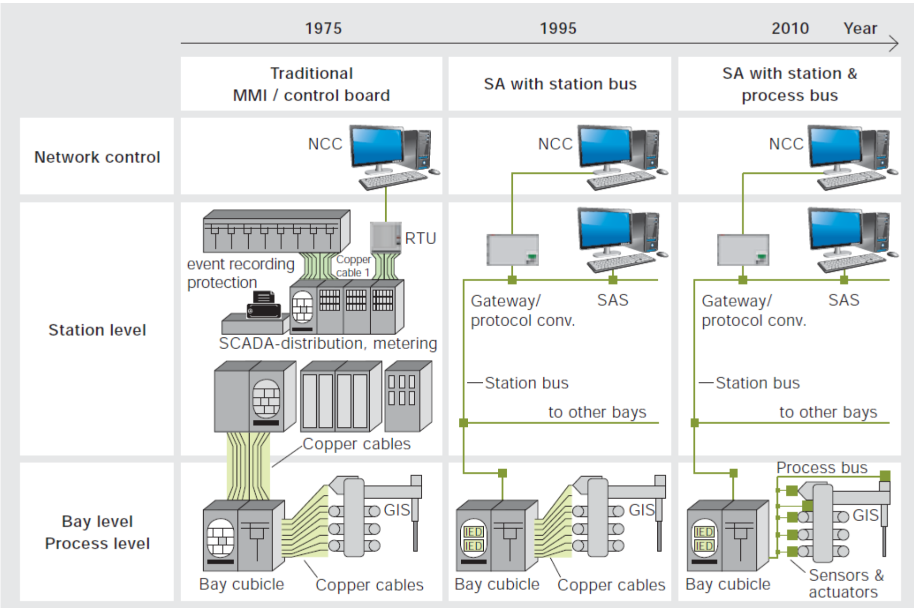

Figure 6. Development of control architecture in electricity distribution networks. (ABB 2010c: 34).

Some functions in a SCADA system are required to be controlled centrally for example DSM and scheduling of load shedding sequences. Centralized SCADA systems are feasible when implementing intelligent operations like sequence capability, network diagram, asset database, hardware and software maintenance and central configuration control. The major challenge is implementing a suitable and cost effective communication infrastructure, which takes into account physical distances, the risk of a failure in a single point, sluggish response (a risk to untimed sequential operations) and testing difficulties. (Chowdhury et al. 2009: 110–111)

A centralized SCADA system for large or medium size of distribution networks is illustrated in the Figure 7. In the NCC there are scalable servers or workstations and a dedicated computer for communication units. Communication units are used for connecting substations and output devices, and they include a processor and a memory unit. The system comprises of a redundant SCADA server and a redundant DMS server. (ABB 2010a: 6; ABB 2000: 408–409; ABB 2010b: 2).

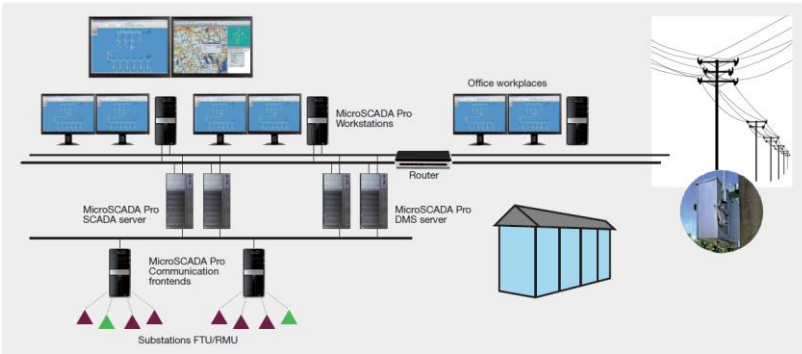

Figure 7. SCADA/DMS regional control center. (ABB 2010a: 6).

A centralized SCADA system for small distribution networks is illustrated in the Figure 8. The system comprises of the redundant SCADA/DMS servers, which are connected to substations and remote controlled switching devices by means of communication units. (ABB 2010a: 7).

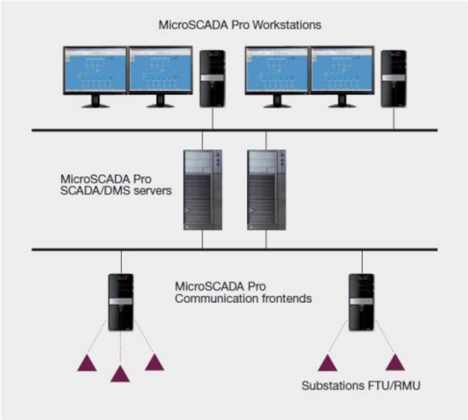

Figure 8. SCADA/DMS local control center. (ABB 2010a: 7).

Distributed SCADA systems comprise of SCADA systems located in substations. Challenges arise from incompatibility issues with the central SCADA system, necessity of additional maintenance facilities, availability of suitable cost-effective management tool (multiple distributed operations) and requirement of field staff visits for logic modification. (Chowdhury et al. 2009: 111). An example of distributed SCADA system, which comprises of a substation server and workstation with an integrated gateway, for SA and monitoring, is illustrated in the Figure 9. (ABB 2010b: 4).

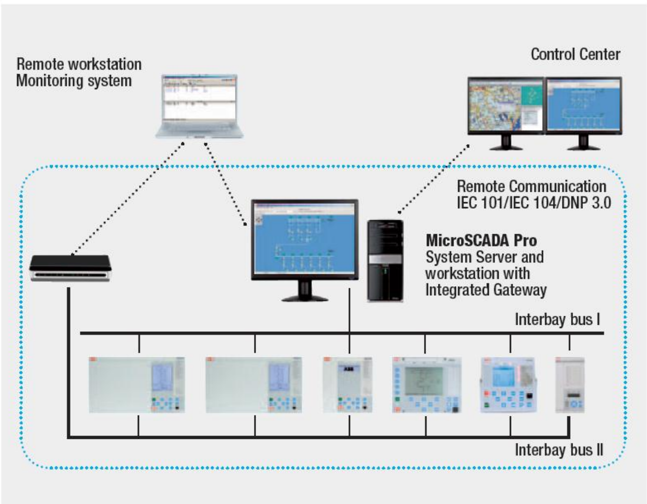

Figure 9. SCADA for SA and monitoring system. (ABB 2010b: 4).

The SA system can be divided into four levels, which are device (or process), feeder, substation and remote control level as the Figure 10 presents. Communication interface can be a RTU, a protocol gateway or a substation computer.

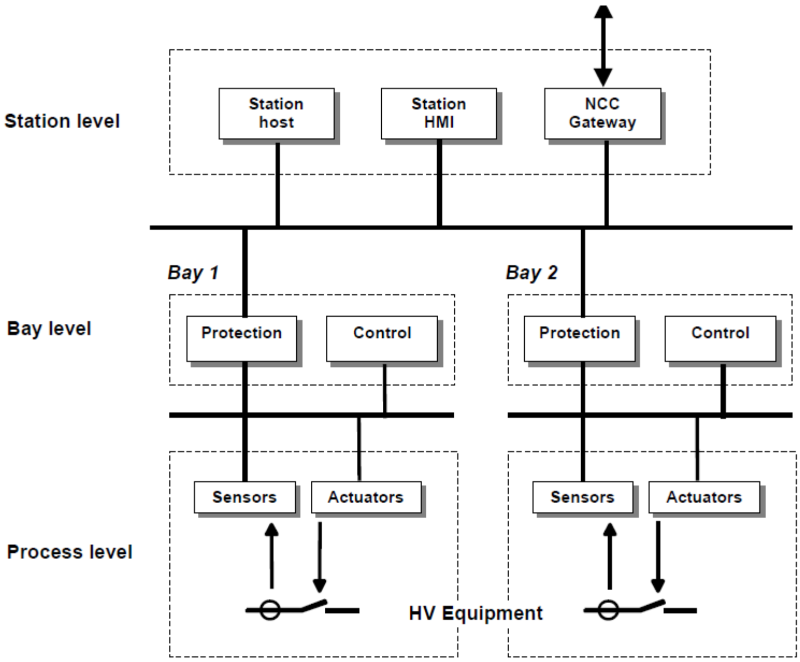

Figure 10. The logical scheme of a SA system.

2.2.2 Components

The Figure 11 presents an example of a SCADA system and major of its main components, which generally are:

- A central host computer server or servers also called a SCADA center, master station, or master terminal unit (MTU).
- Field data interface devices (usually RTUs),
- A communications system for transferring data between RTUs, control units and the MTU.
- A collection of standard and/or custom software or HMI software or man machine interface (MMI) software systems
- IEDs
- Communication unit like a RTU, a gateway or a substation computer

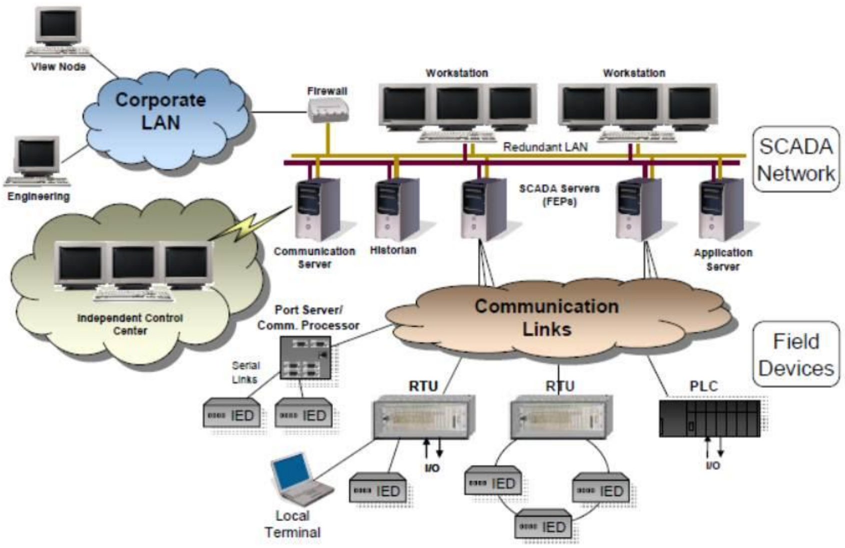

Figure 11. An example of a SCADA system and its main components. (ABB 2010b: 4).

IEDs are intended for bay control as well as for busbar, line differential, transformer, breaker, generator protection amongst others. RTUs interface the devices to be controlled with the SCADA system. A typical RTU consists of a communication interface, a processor, environmental sensors, by-pass switches and a device bus or a field bus to communicate with devices and/or interface boards. The interface boards handles I/O signals (analogue, digital or both) and they are capable of protection against voltage surges. Interface boards are normally wired to physical objects. Some RTUs can be connected directly to the system without a bus interface for monitoring and controlling few devices. In most SCADA systems high-current relays are connected to a digital output (DO) board for switching devices. Analogue inputs (AIs) are usually 24 V with a current range between 4 and 20 mA. The RTU converts AI-data into appropriate signals to the HMI or to the MMI. The RTU uses DO board to execute any control command like switching operation per signal from SCADA. Different types of RTUs are presented in the Figure 12. (Chowdhury et al. 2009: 113).

Figure 12. A rack mountable and DIN rail mountable RTUs and a RTU module for integration. (ABB 2010d: 3).

The Figure 13 presents a station computer usage for local and remote control and monitoring of substation IEDs as well as for interoperability between the bay level and the network control center level.

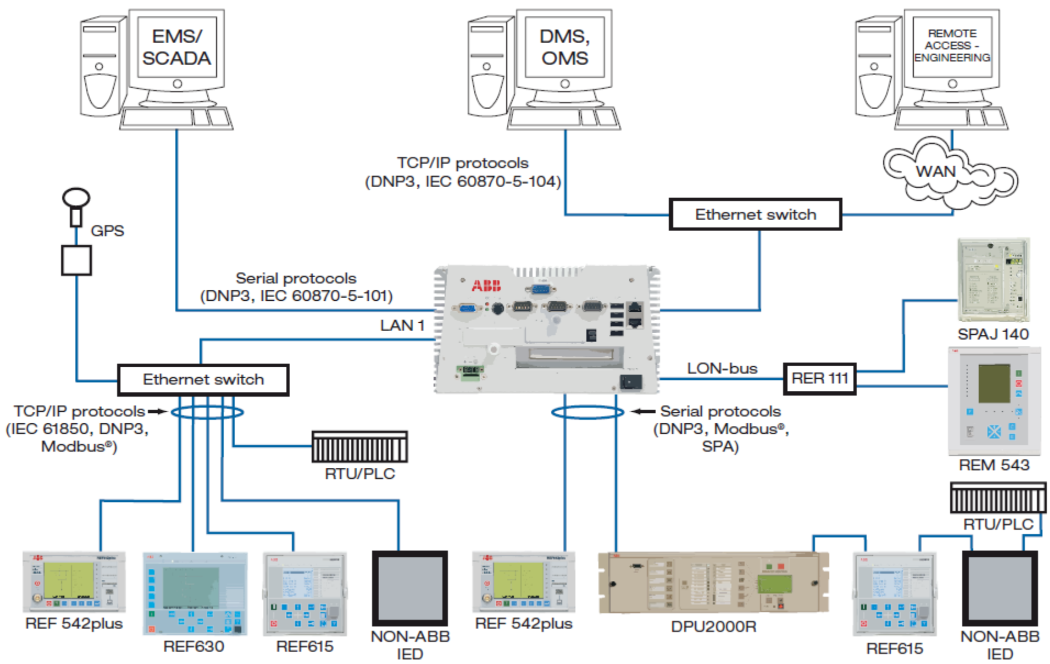

Figure 13. An overview of using a station computer in a utility substation. (ABB 2011: 3).

HMI devices provide processed data to the human operator for control actions. The HMI monitors and controls RTUs, PLCs and other control devices in a standardized way. The SCADA system provides data to the HMI after gathering information from control devices via a standard network. The HMIs are linked to a database for acquiring diagnostic data, scheduled maintenance procedures, logistic information and schematics for a particular sensor or a machine as well as troubleshooting. A major manufactures offer an integrated HMI/SCADA system that use non-proprietary open communication protocols. HMIs are fully graphical and software supports redundancy of applications or hot-standby. An application consists of databases, reports and drawings amongst others. The hot-standby system updates all alternating data of the real-time application into the shading application. Backup and testing new software can be made without system disturbance. In the hot-standby system the server is able to move from recovery through to normal operation while users continue running applications. (Chowdhury et al. 2009: 112; ABB 2000: 408–409).

The Figure 14 presents utilization of a compact module for a communication gateway, a control system HMI and a communication server. The module provides a communication gateway for several protocols and interfaces as well as connections to IEDs. In addition HMI of the module enables monitoring and control of the connected processes. The module is a front-end device capable for hot-standby configuration.

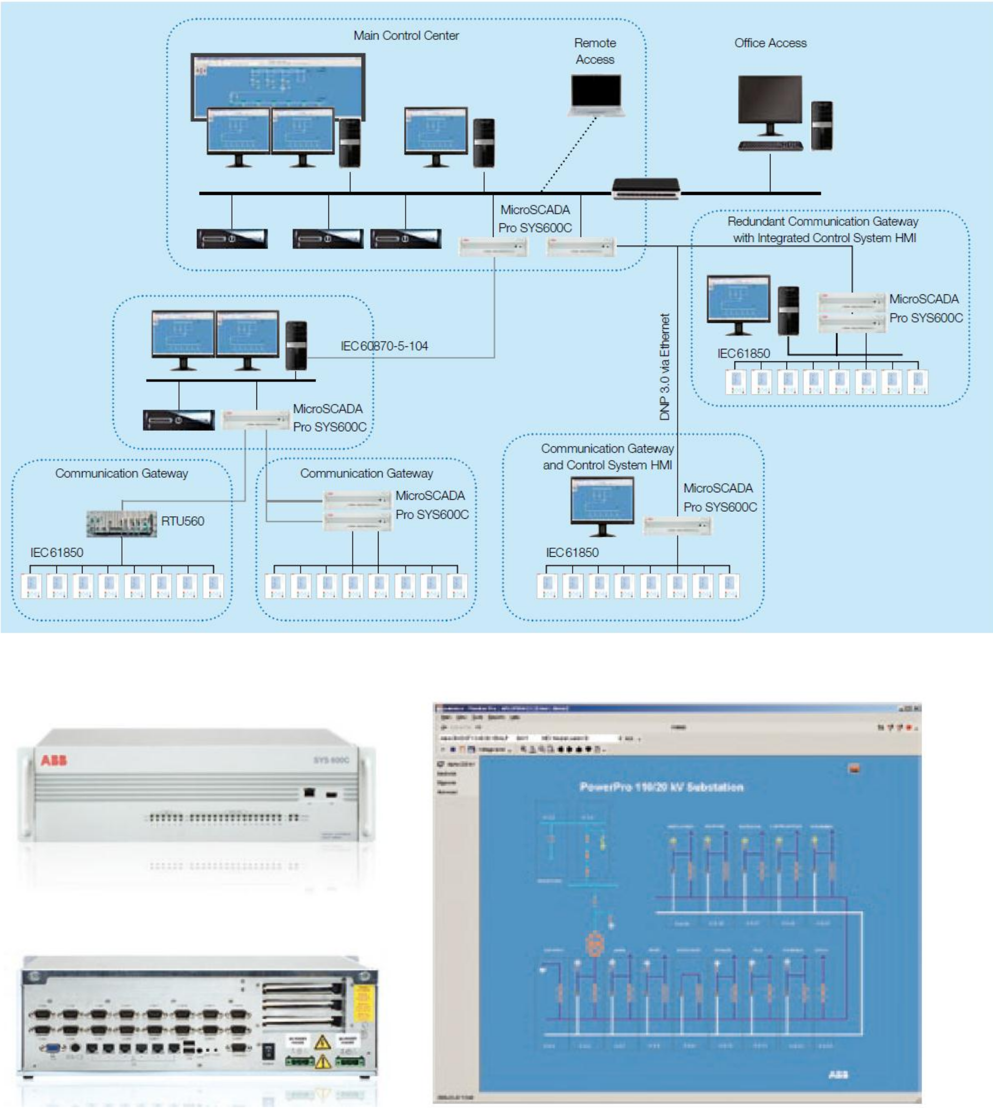

Figure 14. Utilization of a compact module for communication gateway, for control system HMI and for communication server. (ABB 2006: 3).

2.3 Data and information systems

Data and information systems, which provide the above-mentioned applications with supporting communications and with monitoring and controlling field data interface devices, are follows:

- Distribution management system (DMS)
- Network control system (NCS)

- Network information system (NIS)
- Geographical information system (GIS)
- Customer information system (CIS)
- Distribution energy management (DEM)
- Material information system (MIS)
- Feeder automation (FA) in substations

Network control system (NCS) or SCADA enables measurements, event data, remote control, remote setting of device parameters and report of measurements as well as management of switchings. Basic functions of the NCS are:

- *Remote measurements* like bus bar voltage at a substation, currents in feeders, fault currents measured by protection relays, parameter settings of protection relays, energy measurements.
- *Event data* like position indications of switching devices, starting values and tripping commands of protection relays as well as position indications of OLTCs.
- *Remote control* like switching devices at substations, disconnector stations, diesel generators and customer loads (heating, sauna stove).
- *Remote settings* like parameters of protection relays or other bay connected devices
- *Reporting* like operator defined reports as energy supplied in a given substation and time period. (Vaara 2011: 14).

Distribution management system (DMS) is a real-time system for decision support, which functions are based on real-time data from the NCS integrated with static data from network information system (NIS), geographic information system (GIS) and customer information system (CIS). Information from NIS is used to create the static model of the network including data about locations as well as characteristics and connectivity of network components. Real-time information about switchings and state indications from NCS is added to the static model for creating a dynamic model of the network. (Adine 2010: 41).

DMS functions require following data from the NCS:

- Switching status of disconnectors and circuit breakers
- Measurements from substations and remote locations like telecontrolled switching stations, distribution transformer stations and customers connection points
    - Electrical (current, voltage, power etc.)
    - Condition (temperature etc.)
    - Weather
- Relay information
- State of fault detectors

DMS performs on-line load calculation, which is based on load curves, outdoor temperature measurements and network data from the NIS. The result of the calculation is bus voltages and line power flows. To produce accurate values, the loads of feeders are re-adjusted according to the real-time measurements. The load distribution inside the feeders remains uncertain meaning the line currents and voltage levels. By increasing real-time measurements would improve accuracy of load calculations.

Contents of a DMS vary because of many supplies, but a highly integrated DMS provides functions like:

- Monitoring of network state and topology
- Modelling and calculations techniques like load modelling, state estimation and load forecasting as well as power flow, fault and reliability analysis
- Fault management including trouble call management, fault reporting, fault location and diagnosis as well as fault separation and supply restoration
- Planning functions for operations like scheduled outages, power flow management, volt/var optimization and reconfiguration

Network information system (NIS) is generally applied for planning and maintaining the distribution network. NIS integrates the network data with calculation for network planning, maintenance and condition monitoring purposes. The main objective of NIS is to find optimum between technical and financial matters. The condition of network is often managed with NIS, which includes monitoring the aging components and managing the maintenance and renovation actions. NIS is typically based on GIS and is highly integrated to other systems like CIS and MIS. NIS and DMS usually share the same network database as well the functionalities. NIS is generally used for off-line planning and data management. (Adine 2010: 42–43).

Geographical information system (GIS) provides background maps and data for coordination of network objects in the MV level and sometimes in the LV level too.

The main task of *feeder automation* (FA) is to limit the affected zone and time in a fault situation. In addition *the zone concept* is developed to minimize the affected area of the distribution network in fault situations. By dividing the feeder into sections or zones using line reclosers, automatic sectionalizers and remotely controlled disconnectors as zone dividers. That is by integrating protection and reclosing functions deeper into the network, directs reclosing functions and interruptions selectively only to the problematic parts. Main feeder zones include lateral feeders (or branches), which form their own protection and control zones. (ABB 2009: 2).

Customer information system (CIS) is intended for billing, customer service, advising, contract management and marketing. The customer database includes information about customers and consumption points. The data from CIS is needed in load modeling for NIS which is typically based on statistical load profiles.

A separate *metering data management (MDM)* system is needed to collect, store and handle measured data as well as meter information management. The AMR system is typically excluded from MDM.

Other data and information systems are for example distribution energy management (DEM) system, mobile workforce management, work management systems, enterprise asset management systems and they are integrated with NIS, CIS, SCADA or DMS.

2.4 Communications

Before implementing the control scheme of SCADA, the volume of data transmitted over long distances need to be reviewed. Normally two, centralized and distributed, control schemes are applied. In addition SCADA systems operate in both dense urban and dispersed rural networks and this is why a combination of several communication methods is applied. The existing communication structure is mainly based on copper cables, but the use of fibre optics is increasing because of the efficiency and reliability of data transmission despite of the fact its high cost.

DA communication facilities must extend, replace, supplement or include existing media and embed them into general communication architecture. The components of a communication system are generally referred according to the International Organization for Standardization (ISO) open system interconnection (OSI) model. OSI model represents communication protocols in seven layers, which are illustrated in the Figure 15. (Northgote-Green et al. 2007: 289–291).

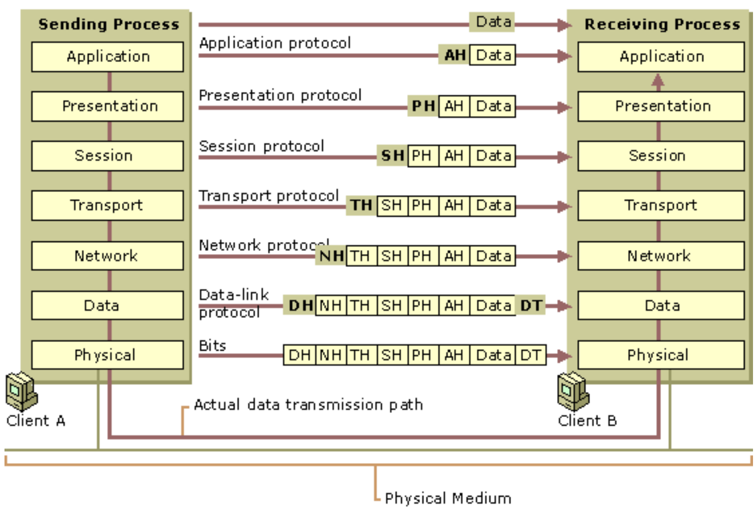

Figure 15. Data flow in the OSI model. (Microsoft 2012).

Physical link or media options in DA communication are illustrated in the Figure 16. The physical link provides the communication medium such as copper wires. For FA fibre optics, copper wires and wireless physical links are used generally. A series cable RS-232 can be the physical link between devices in a simple case. The communication protocol may specify the address of the transmitting device, the address of receiving device, information of data type (like a control command), the data itself, error detection as well as other information. (Northgote-Green et al. 2007: 291).

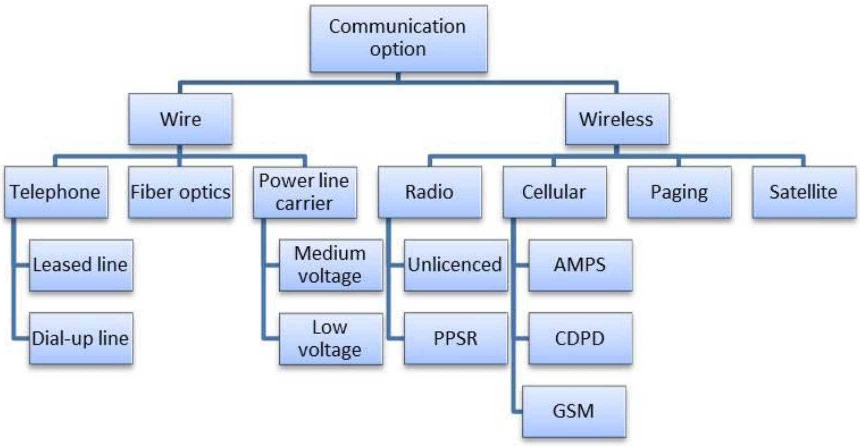

Figure 16. Distribution automation communication technology options. (Northgote-Green et al. 2007: 292).

Selecting appropriate communication technology depends on several factors like utility requirements and objectives, physical network configuration and existing communication systems. For improving communications in DA successfully, requires effective communication architectures and protocols. The data varies in importance so it has priority. Hybrid communications allows subregions to be managed according to the data, topology and communication type. In a hybrid concept communication facilities are linked together via intelligent node controllers or gateways that handles communication interfaces data and protocol transformation and independent control algorithms. (Northgote-Green et al. 2007: 291–292).

Commonly used communication protocols in DA are Modbus, distributed network protocol DNP 3.0, International Electrotechnical Commission (IEC) 60870-5-101 and Utility Communications Architecture protocol (UCA) 2.0. Modbus is a master-slave communication protocol between intelligent devices, which have serial transmission modes; Modbus ASCII and Modbus RTU. DNP3.0 is also a master-slave protocol between the master station computer and the substation computer. DNP3.0 consists of three layers and one pseudo layer, which IEC denominates as enhanced performance architecture (EPA). The physical layer handles for example states of the media and synchronization. Physical layer is normally serial RS-232 or RS-485 (also known as TIA/EIA-485). IEC 60870-5-101 is a messaging structure between RTU and IED. IEC 60870-5-101 uses the simplified reference model or EPA model. (Northgote-Green et al. 2007: 333–343).

Synchronization is essential to keep DA systems in the uniform time and therefore a clock signal is required. The signal can be from the global positioning system (GPS) satellites or network time protocol (NTP). NTP protocol offers time stamps for organizing events of different functions. For example IEC 61850 support synchronized measurements using GPS satellite for synchronization so time stamp uses the coordinated universal (UTC) time, which is the primary time standard.

Currently used media and protocols in Finland for long distance communication links and some local automation are presented in the Table 4. The Table 5 presents average service range and speed of data transmission of communication media types. Fibre optics is mostly used for remote control of primary substations and SA. For remote control of HV/MV substations own or leased radio frequencies are also used. In addition TCP/IP networks and telephone lines can be found. The protocols used for remote control of primary substation are mostly IEC 60870-5-101 and -104 and additionally DNP as well Modbus can be found. Remote control of secondary substations exists few in numbers, but present systems communicates via wireless networks straight with the NCS or via the RTU in the HV/MV substation. The protocols used are commonly IEC 60870-5-1, -104 and American National Standards Institute (ANSI) standards. (Sirviö 2011; Vähämäki 2009).

Table 4. Media and protocols used in DA in Finland.

Location	Media	Protocol
Remote control of HV/MV substation	Fiber optics, RF, TCP/IP networks, telephone lines	IEC 60870-5-101 IEC 60870-5-104, DNP 3.0, DNP TCP, Modbus
HV/MV substation automation i.e. SA	Fiber optics, RS	IEC 61850, IEC 60870-5-103, LON-bus, SPA-bus
Remote control of CSS and indood type SS	RF, 2G, 3G RS, (fiber optics, TCP/IP netwokrs)	IEC 60870-5-101 IEC 60870-5-104, ANSI, (Modbus, Modbus TCP, SMS messages, DNP TCP)
Remote control of pole mounted SS	N/A	N/A
SS local automation	N/A	N/A
AMR	PLC, 2G, 3G, (RS, fiber optics, wlan, RF)	Modbus, LON, LonTalk (Echelon), DLMS/COSEM (Device Language Message Specification, Companion Specification for Energy Metering IEC 60256
Home automation	RS, RF	KNX, Zigbee

Table 5. Average service range and speed of data transmission of communication media types. (Kauhaniemi 2011).

Media	Sercice range	Speed
PLC	300-500m	1-3 kbps, in practice 1.5 kbps
2G/GPRS	covering	53.6 kbps, in practice 20-40 kbps
3G	covering in cities	max 384 kbps, in practice 150-300kbps
Copper cable	1-5 km	10 Mbit/s
Fiber optics	10-100 km	10-100 Mbit/s
Wlan	50-100 m	11 Mbit/s
RF	50-100 m	1-100 kbps

At present wireless communication is mostly applied between DSO management systems and systems of the LV distribution networks. In future it is desired to exploit cellular public wireless networks for connecting the functions required of LV distribution networks. At present cellular public wireless networks are operating for second generation (2G) or global system for mobile communications (GSM), 2.5G or general packet radio service (GPRS), third generation (3G) or universal mobile telecommunication system (UMTS) and in future fourth generation (4G) or long term evolution (LTE) technologies. (Sirviö 2011). The Figure 17 presents speed ranges of wireless technologies by the range of mobility.

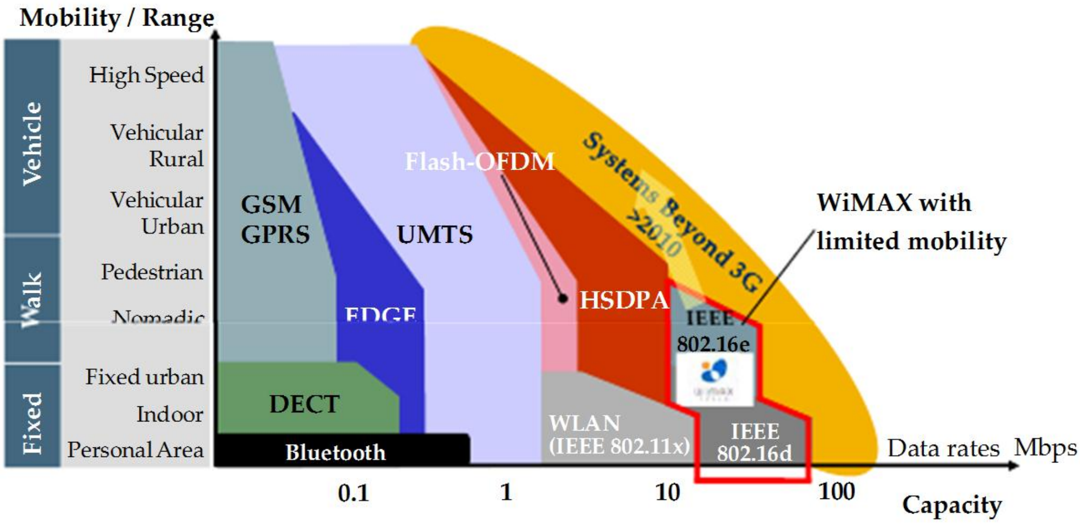

Figure 17. Wireless technology positioning. (Yang 2009).

2.5 Network control hierarchy

Network control hierarchy can be divided into three levels, which are area control (centralized), automatic control system (decentralized) and protection level. Area control level is used for coordinating the functions of devices, which includes coordination of protection relay settings and coordinated voltage control. The coordination of control and protection devices requires measurement data from selected nodes from distribution network. The automatic control system level comprises of voltage control in MV network as well as in LV network. In the MV network the voltage level is managed by controlling automatic voltage regulators (AVR) of OLTCs of primary transformers. In the LV network the voltage level is controlled manually in secondary substations by controlling off-load tap changers of secondary transformers. In future when connecting more DG into LV distribution network, automated voltage control is much desired. Protection level comprises of distribution feeder protection and loss-of-mains (LOM) protection.

2.6 Future trends

The change of control systems from passive networks towards more active distribution networks is considered to be made out of three stages: active unit, active cell and active network. In the active unit stage the control is based on the measurements of local devices, which could be implemented by a RTU or similar capable of standard SCADA communication. In the active cell stage multiple active units are controlled by and overriding control system. For example an active cell system could be comprised of multiple transformers, whose AVR relays are centrally coordinated. Thereafter the active network is formed by a group of active cells and this level is used for coordinating adjacent networks. The active network stage is advantageous for adjusting the network load flow and minimizing effects. (Adine 2010: 67–68).

3 MAIN ELEMENTS OF LOW VOLTAGE DISTRIBUTION

The development of electricity distribution networks is mainly introduced by way of Smart Grids concept at present. Evolution towards Smart Grids contains development of distributed energy resources (DER), local intelligence and communication. DER comprises of DGs, ESs, EVs and controllable loads. The number of DG units will increase in distribution networks focusing to raise renewable energy resources (RES) share, so DG units based on renewable energy are the main driver for the development towards active distribution networks at the moment. (VTT 2010: 266; Laaksonen 2011: 1).

3.1 Distribution network

LV distribution networks in Finland are basically radial type. In rural areas there is few-end users connected to *a pole mounted substation* as for in urban areas there can be even hundreds of end-users connected to *a compact secondary substation (CSS)* or to *an in-door type secondary substation*. In urban areas backup power supply can be arranged by connecting secondary substations together having a connection point in a CSS or in *a cable distribution cabinet (CDC)*, which form an open ring distribution system. In Finland pole mounted substations represent at 80 % of secondary substations. (Löf 2009). General forms of LV distribution networks in rural and in urban areas are presented in the Figure 18.

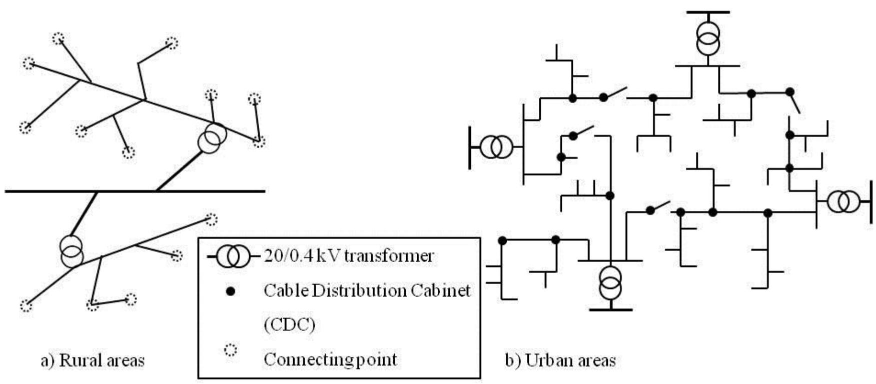

Figure 18. General structures of LV distribution in Finland a) in rural areas b) in urban areas. (Löf 2009: 5).

In rural area LV distribution networks comprise of a pole mounted secondary substation (rated 20/0.4 kV, 20/1 kV or 20/1/0.4 kV which can be isolated by means of a disconnector), pole mounted fuse switches and overhead lines (AMKA) or cable (AXMK) to customers. The trend is to build more 1 kV networks in rural areas and use satellite type secondary substations substituting the pole mounted types.

In urban areas LV networks are mostly cabled from CSS via CDCs to customers. The Figure 19 presents an example of LV distribution network in urban area from a CSS to different types of customers like residential, commercial and light industrial applications.

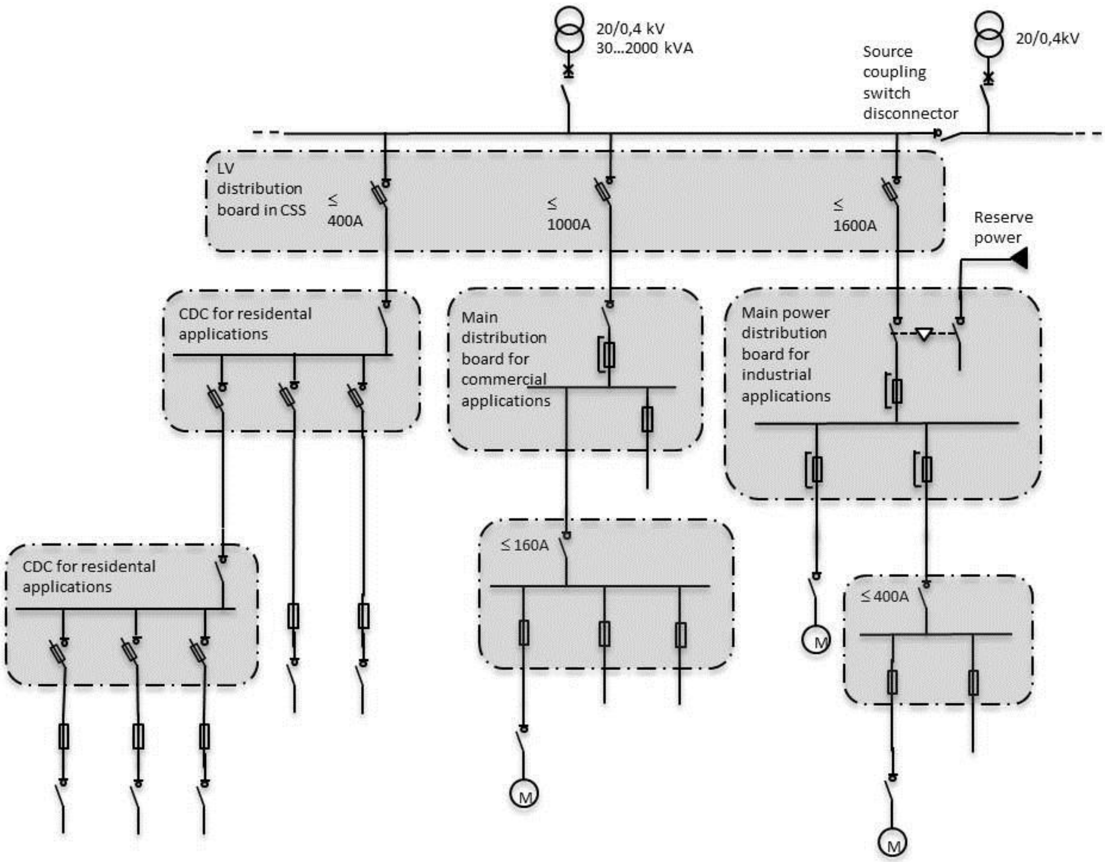

Figure 19. An example of LV distribution in urban area (Sirviö 2010: 11).

A CSS generally comprises of a MV switchgear, a distribution transformer (20/0.4 kV), LV switchboards, connections and auxiliary equipment. The transformer can be isolated by means of CBs or disconnectors at the MV and the LV side. LV feeders in the CSS are implemented generally by fuse switches (as well as feeders in CDCs). The Figure 20 presents a typical main diagram of a LV switchboard in a CSS.

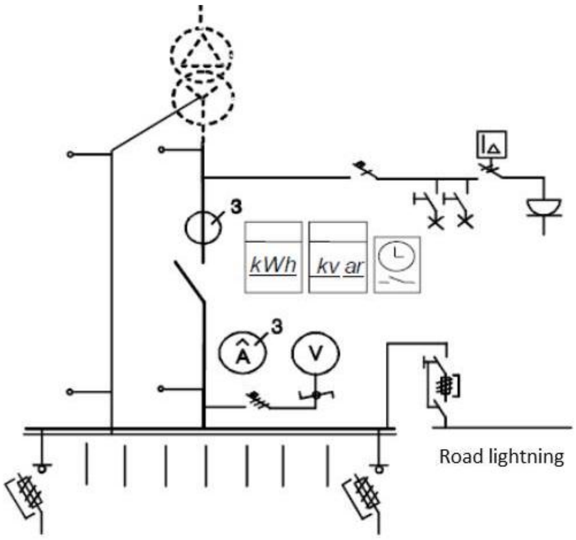

Figure 20. A typical main diagram of a LV switchboard in a CSS. (ABB 2000).

LV distribution networks are mostly operated manually containing switchings under normal operations and supply restoring after a fault situation. Remote controllable main CBs are located in some CSSs, which allow remote controlled power supply as well as restore of power supply after a fault is cleared. (Sirviö 2011).

At present CSSs are connected to the DA system for remote control of the MV main switch or the main CB. Usually the main switching device is controlled via a RTU unit located in the secondary substation, and is communicating with a RTU unit in the primary substation or straight with the NCS. The communication network is commonly wireless, which is realized by GSM, GPRS or own radio network. In addition a measuring and monitoring unit can be installed in the CSS for current and voltage measurements as well as monitoring the temperature of transformer. The measuring and monitoring unit communicates mostly with the NCS via wireless network. (Sirviö 2011: 25).

In the nearest future the data flow desired between CSS and NCS includes (Sirviö 2011: 27):

- Control messages to disconnectors and CBs

- Status indications from disconnectors and CBs, short circuit indicators and door switches
- Information of loadings and quality of electricity
- Control of the local automation system or self-diagnosis.

More sophisticated functions for secondary substation automation in Finland are studied in the Vaha-research project (Lehtonen et al. 2011).

Safety and protection is executed in LV distribution networks by earthings, overcurrent and short circuit protections. In Finland 0.4 kV distribution network is established as a TN-C system, where the LV network have the operational earthing so the wiring includes a combined protective earth and neutral (PEN) conductor. For TN-C-S systems the PEN conductor is separated to PE and N conductors at customers. 1 kV networks are established as IT systems, which are isolated from the earth like MV networks. Overcurrent and short circuit protection are generally implemented with fusible devices in TN-C systems and in 1 kV systems with CBs.

Overcurrent, short circuit and touch voltage protection are connected together in fusible protection. A fuse have to perform its rated current, blow in specified over current per time, blow quick enough in short circuit circumstances, even in one phase short circuits in the end point of the network. The standard SFS 6000-8-801 defines that the time of switching off the short circuit must not exceed 5 s in the LV distribution network. Exceptions are allowed under consideration of a DSO, but the absolute limit is 15 s. In TN installations of customers the requirement is 0.4 s, which limits the touch voltage to be 75 V at maximum. Selectivity of fusible protection is achieved easily by leaving at least one category of rated current between the sequential fuses.

3.2 Distributed generation

Requirements of electricity efficiency force to produce energy locally in future, which will reduce the amount of power loss in transmission of electricity. DG is on-site power generation, which is also called as embedded or decentralised generation. In addition

DG is small scale energy production, which can use renewable or non-renewable energy resources. In future RES are striven to be utilised increasingly in local energy production. Renewable energy is obtained generally from biomass, wind, solar and hydro among others. (VTT 2010). Local renewable power generation is implemented by many technologies including:

- Combined heat and power (CHP) and Micro CHP
- Fuel cells
- Microturbines
- PhotoVoltaic (PV) systems
- Wind power systems

Finnish Electricity Market Act (386/1995) defines small-scale production for a single power plant or a complex of power plants up to maximum 2 MVA. In addition the small-scale production is defined usually for all production connected to the distribution grid (Sihvola 2009).

Small-scale production plants can be divided into three categories according to the connection methods to the external grid. The connection methods are directly connected asynchronous or synchronous generator or connection with power electronics. The majority of DGs is connected with power electronics at present and the characteristics of power electronics determine the behaviour of a production plant in a fault situation. (Ylä-Outinen 2011).

The Figure 21 presents a DG interfacing system in general. The power engine can be a wind turbine, a microturbine, a fuel cell, a PV cell or a diesel engine. Energy produced by a wind turbine, a microturbine or a diesel engine is converted to electricity with a generator, which can be connected straight to the grid or via a frequency converter. Direct current (DC) power conversion to alternating current (AC) power is required for fuel cells and PV cells. The measuring unit for power measurements and quality of electricity can be a separate unit or the functions can be included in a control unit of a protective device like a CB. A device for isolation of the DG equipment is needed for a reliable disconnection from the main distribution grid. (Valkonen et al. 2005: 56).

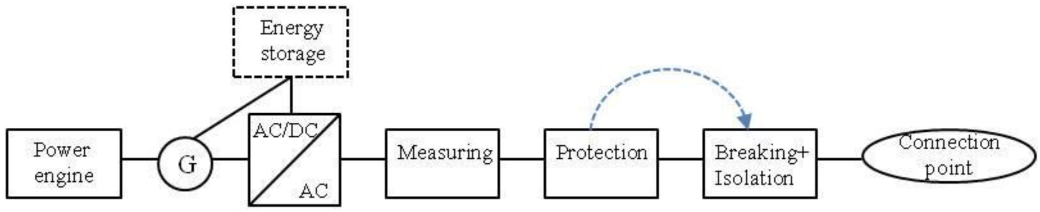

Figure 21. DG interfacing system in general. (Valkonen et al. 2005: 56).

3.2.1 Interconnection methods to the national grid

Based on the interconnection power of the production, the type of production is divided either to the *small-scale production* or to the *micro production*. A small-scale production is defined to be up to 2 MVA (Finnish Electricity Market Act; 1995: 3§). Requirements for connecting micro production or micro power plants to the national grid are stated in the European standard EN 50438, which the Finnish guideline Network Recommendation (YA9:09) base on. Both publications deals with production, which is connected to the national grid with 3 x 16 A fuses maximum. By this way the maximum power allowed to connect micro production is approximately 11 kVA. (Energiateollisuus 2009: 3).

Technical requirements for connecting small scale and micro generation to a DSO's networks in Finland are defined in connection conditions of DSO's, which are based on general recommendations and standards applicable. Generally DG equipment is classified into the four main categories of connection conditions by operating principles and technologies utilized. The four main classes are introduced in the following examples.

Class 1: The DG unit is not connected to the national grid. The load is supplied either from the grid or from the DG unit. Parallel operation is prevented with a manual operated change over switch disconnector including a mechanical interlock and in addition 0-positon is recommended. (Sener 2001: 4; Helen Sähköverkko 2009: 3; Fortum Distribution 2010: 3). An example of the class 1 DG equipment connected to the national grid is presented in the Figure 22.

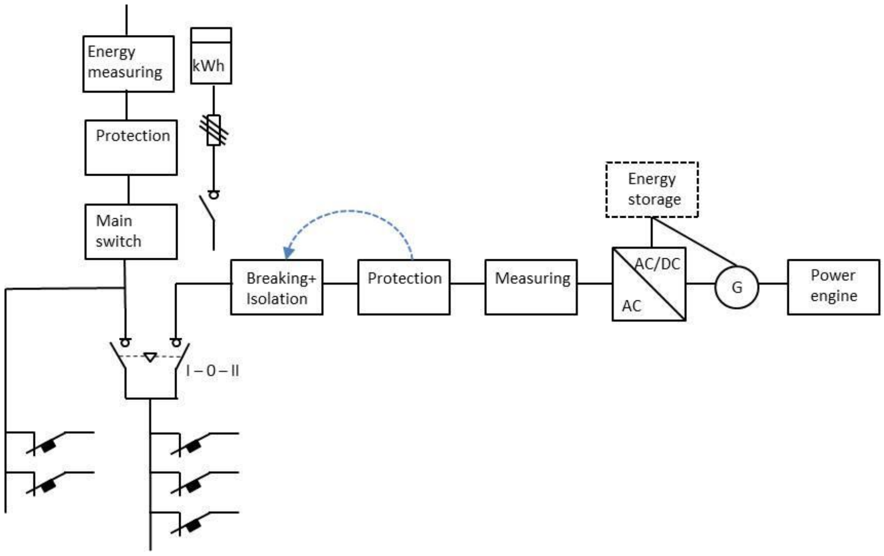

Figure 22. An example of a class1 DG equipment connected to the DSO's network.

Class 2: The DG unit is not connected to the national grid. The load is supplied either from the grid or from the DG. Parallel operation is prevented with an automatic operated change-over switch including a mechanical interlock. The change over switch is either a contactor or a CB based device. Before the DG unit starts to feed loads, off time of disconnecting the national grid is required to be reliable. After a recovery of the main supply, the load fed by the DG unit is allowed to be re-connected to utility grid by synchronizing when nominal voltage has appeared at least for 10 min. Parallel operation has to be limited to be maximum 5 s with relays. A lockable switch-disconnector is required for isolation of the DG equipment from the national grid. (Sener 2001: 4; Helen Sähköverkko 2009: 3–4; Fortum Distribution 2010: 3).

An example of class 2 DG equipment connected to the national grid is presented in the Figure 23.

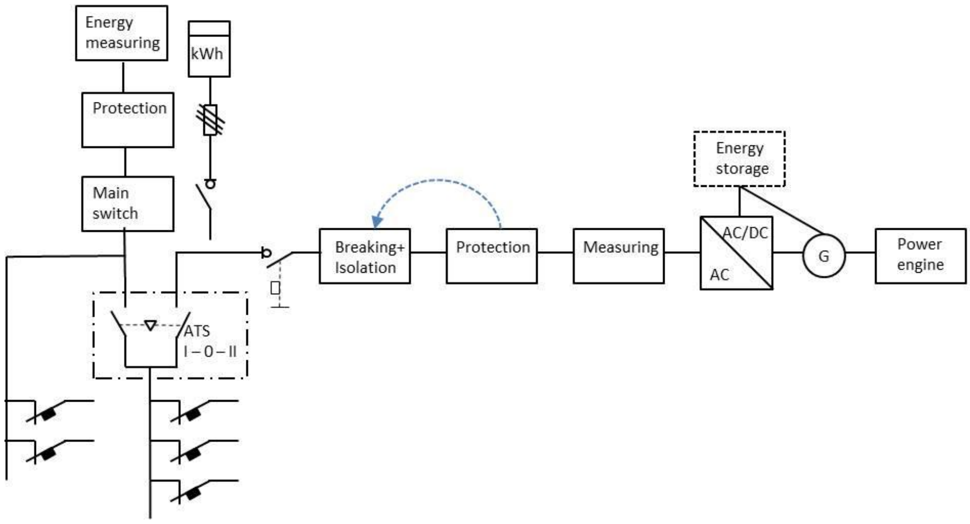

Figure 23. An example of a class 2 DG equipment connected to the DSO's network.

Class 3a: The DG unit is operating parallel with the national grid and energy flow to the national grid is prevented. Direction of energy flow is required to be monitored and controlled to be maximum 5 s to the national grid with relays. In order to supply energy to the national grid, the output power of the DG unit has to be reduced or it has to be disconnected. For example an energy meter can send the control signal. In fault and in LOM situations of the national grid, the protective devices of the DG equipment have to disconnect the DG unit from the national grid. Rate of change of frequency (ROCOF), impedance and under voltage are monitored with relays of the LOM protection device. After recovery of the main supply, the loads fed by the DG unit are allowed to be reconnected to the utility grid by synchronizing after nominal voltage has appeared at least for 10 min. A lockable switch-disconnector is required for isolation like for the class 2 equipment. Further requirements exist for voltage variations, flickers, power factor, and current harmonics. Short circuit level has to be verified to exceed at minimum $25 \cdot I_n$ of the DG unit at the connection point between utility and customer. (Sener 2001: 4; Helen Sähköverkko 2009: 4–7; Fortum Distribution 2010: 3–5).

An example of class 3a DG equipment connected to the national grid is presented in the Figure 24.

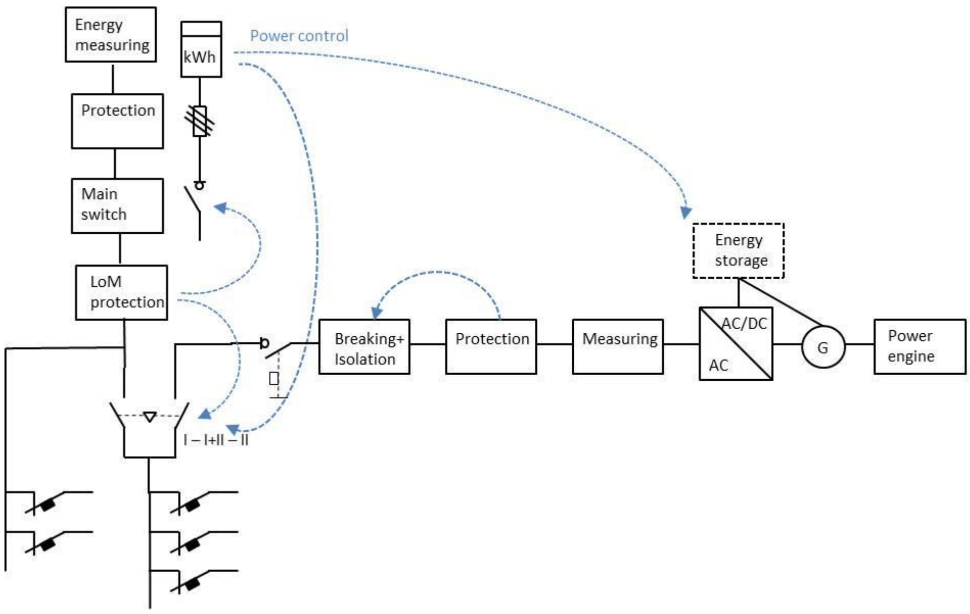

Figure 24. An example of class 3a DG equipment connected to the DSO's network.

Class 3b: Distributed *micro generation* operating parallel with the national grid and energy flow to the national grid is allowed but without credits. In fault and in LOM situations of the national grid, the requirements for disconnection and re-connection are the same as for class 3a equipment. A lockable switch-disconnector is required for isolation like for classes 2 and 3a equipment. Further, requirements exist for voltage variations, flickers, power factor and current harmonics. Operational requirements for micro generation are according to EN 50438. Class 3b DG equipment is allowed to have nominal current at maximum 16 A per phase corresponding 11 kVA in three phase system, nevertheless in Finland the standard EN 50438 is applied for connecting power up to 30 kVA or even 50 kVA. A class 3b DG equipment can consist of several DG units, but in this case the total nominal current of combined DG units is limited to be maximum 16 A per phase (or 30 – 50 kVA). (Sener 2001: 4; Helen Sähköverkko 2009: 7; Fortum Distribution 2010: 3–5).

An example of class 3b equipment containing several DG units connected to the national grid is presented in the Figure 25.

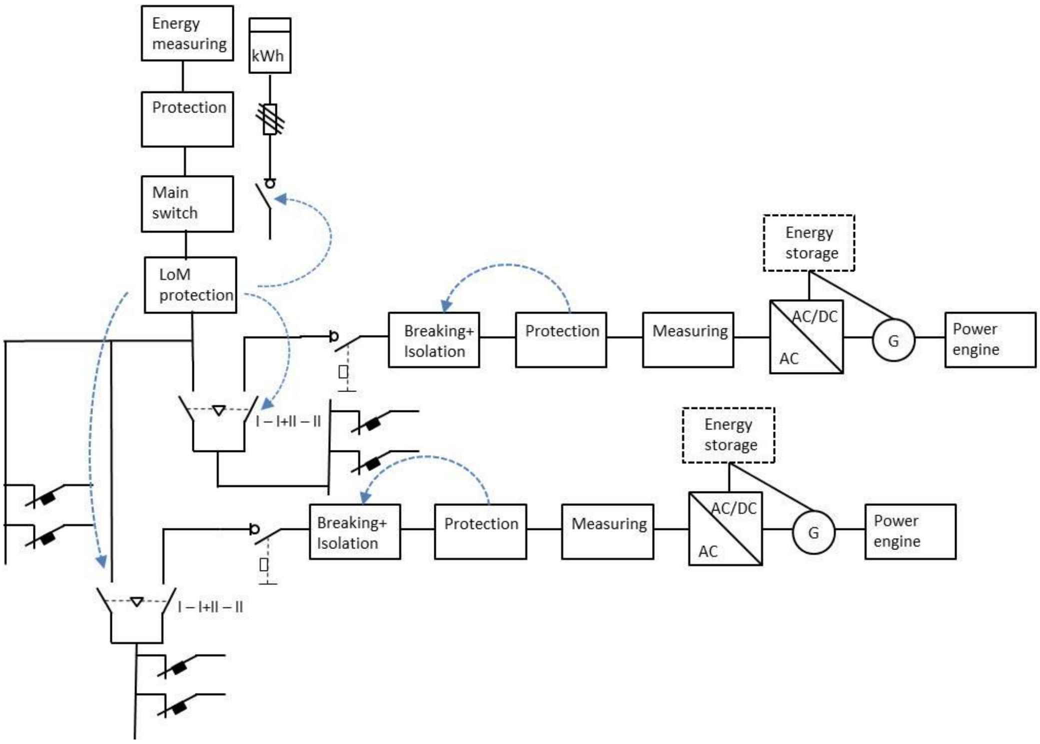

Figure 25. An example of class 3b DG equipment containing several DG sets connected to the DSO's network.

Class 4: The DG unit is operating parallel with the national grid and energy flow to national grid is allowed for sales. In fault and in LOM situations of the national grid, the requirements for disconnection and re-connection are the same as for class 3a and 3b equipment. The DG equipment is required to endure general operation failures of utility distribution network for example short circuits and earth faults with high-speed automatic reclosing (HSR), t = 0.4 s. A lockable switch-disconnector is required for isolation like for classes 2, 3a and 3b equipment. Further requirements are given for voltage variations, flickers, power factor, and current harmonics. The short circuit level of the connection point has to exceed at minimum $25 \cdot I_n$ of the DG equipment (like class 3a). (Sener 2001: 4; Helen Sähköverkko 2009: 8–9; Fortum Distribution 2010: 6–8).

An example of class 4 equipment connected to the national grid is presented in the Figure 26.

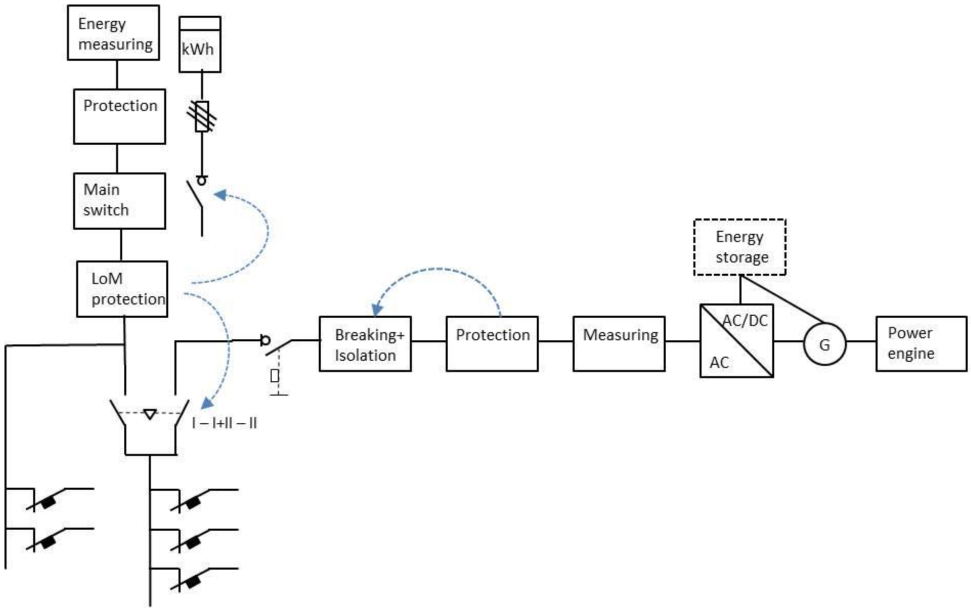

Figure 26. An example of class 4 DG equipment connected to the DSO’s network.

Interconnecting method of micro generation to the national grid can be any of above mentioned classes, but in any case the DG unit is not allowed to supply energy to the national grid and to the islanded network in parallel when using it as a reserve power. SFS6000 DG equipment operating parallel with the national grid is not allowed to produce disturbances accordingly. A protection device is required to disconnect the equipment from national grid if supply disappears, or voltage or frequency is not in limited values. The protection device of the DG equipment has to disconnect the micro generation equipment from the national grid in every fault situation. If the owner of DG unit wants to operate the equipment under the interruption of the main supply, the main line has to be equipped with a change over switching and isolating device or corresponding. A reconnecting operation to the national grid must occur synchronized after 10 min acceptable voltage and frequency, while EN50438 defines that the time for acceptable voltage and frequency has to be at least 3 minutes for AC generators and 20 s via inverter connected DG unit. The DG equipment has to be equipped with a disconnection device for isolating the equipment from national grid generally. The disconnector has to be achievable for the DSO anytime. A summary of the main differences between the classes is presented in the Table 6.

Table 6. The main differences between classified DG units to be connected to Finnish DSO's networks. (Adapted from Energiateollisuus 2011a: 1)

	Operation	**Operation restriction**	**Synchronization**	**Compatibility requirements**	**LoM protection**	**Power of interconnection**	**Energy trading**
Class 1	Separeted operation from the LV distribution network	Parallel operation prevented with a mechanical device	-	-	-	-	-
Class 2		Parallel operation prevented with an automatic device	X	-	-	-	-
Class 3a	Parallel operation with the LV distribution network	Power flow to LV distributon network prevented	X	X	X	$S_k = 25 \cdot S_n \cdot \frac{I_{start}}{I_n}$ ≤ 2 MVA	-
Class 3b		Power flow to LV distributon network allowed	X	X	X	16 A per phase or up to 30 kvA	No payment
Class 4			X	X	X	$S_k = 25 \cdot S_n \cdot \frac{I_{start}}{I_n}$ ≤ 2 MVA	Sales

3.2.2 Terms of connection for distributed generation

DG units connected to the national grid have impacts to the distribution grid, like fast voltage changes and flickers, voltage asymmetry, harmonic and inharmonic over voltages. In normal operating range, the electricity has to meet requirements for quality and power balance, as well as management of power. Outside of normal operating range and in fault situations the DG can be disconnected by the basis of safety and protection requirements. Therefore requirements for connecting DG to the national grid can be divided into three main subjects; *quality of electricity, safety and protection and power balance*. (Valkonen et al. 2005: 54–55).

Requirements for quality of electricity are applicable for class 3a, 3b and 4 DG equipment. Quality of electricity in low and medium voltage grids is defined in SFS-EN 50160 (in the connection point) in normal situation, but it is not applicable for small-scale production (Sener 2001: 6), because DG equipment is required to reach better level of quality. However the standard can be used as a help of the planning. Sener's guideline (as well as EN 50160 partly) defines limits for *voltage drop or rapid voltage changes, voltage harmonics, flicker, and fluctuation* for a small-scale production. In addition Sener (2001: 6–11) defines limits for *current harmonics and power losses*. For micro production (class 3b) the requirements of standard EN 50438 applies.

Voltage drop or *rapid voltage changes* are allowed to be 5 % at maximum, which is caused by starting of the micro power plant or its disconnection from the national grid (SFS-EN 50160). Voltage drop is the basis for connecting size of DG equipment. Voltage change during connecting DG to the national grid can be presented as:

$$\Delta U = i_r \cdot \frac{S_k}{S_n} \cdot U_l, \tag{1}$$

where i_r is the ratio between the switching current and the nominal current, S_k is short circuit power at the common point with other consumer(s), S_n is the nominal power of the DG and U_l is the phase voltage of the national grid. Considering the requirement of 5 % voltage drop, it would be better to have 4 % ($\Delta U/U_l = 0{,}04$) in planning stage. The requirement for the short circuit level in the connection point can be derived from foregoing equation:

$$S_k \geq 25 \cdot i_r \cdot S_n\ . \tag{2}$$

The short circuit level at the low voltage network connections is currently regarded to be I_k = 250 A, so a maximum 7 kVA power plant would be allowed to connected. (Sener 2001, Energiateollisuus 2009: 4). EN 50438 states the maximum output of a micro generation installation can be 3 x 16 A or 11 kVA. These are slightly low connection power, because typical electrically heated house have connection power about 17 kW. Therefore DSOs can apply these requirements also for higher power levels (Energiateollisuus 2009). For example Vattenfall (2011) applies the requirements for powers up to 50 kVA and Helen (2009) applies the up to 30 kVA, which in Finland the most of DSOs use as well (Mäki 2011).

If rapid voltage changes appear several times in a minute, it produces *flickering*. Flickering is presented as a short time (P_{st}) and a long time (P_{lt}) disturbance index. (Sener 2001: 8). According to SFS-EN 50160 95 % of long time disturbance indexes are required to be below 1 in a one week period (Sener 2001: 8). Fortum Distribution (2010: 3–7) requires $P_{lt} \leq 0.2$ and $P_{st} \leq 0.3$ for class 3a and 4 DG equipment.

Limit values for harmonics are feasible to be defined for *current harmonics*, because of spurious voltage dependence on harmonics of currents. (Sener 2001: 9). Limit values for current harmonics are set in SFS-EN 50160 (for example Helen applies) and Sener guideline (for example Fortum applies). Standard EN 50348 for current values below 16 A refers to IEC publication 61000-3-2. EN50438 has the strictest requirements for current harmonic values.

Voltage fluctuation is limited to be U_n ± 10 % at 95 % of 10 minutes mean value of U_{rms} in every week and in every situation the requirement for U_n = +10 / -15 %. (SFS-EN 50160: 8). EN 50438 defines the limits for voltage fluctuations and flicker refers to IEC 61000-3-3, where d_c = 3.3 % max.

According to EN 50438 the electromagnetic compatibility (*EMC) requirements* are according to EN 61000-6-1, EN 61000-6-3 and EN 61000 part 3–5 for micro generators. (Lehto 2009: 43).

Feeder interconnection protection of the main line can be integrated to the DG equipment or it can be separated. The protection should be according to EN 60255-6 (Electrical relays: Measuring relays and protection equipment). The protection disconnects the DG unit in case of fault situations or in case of under/over voltage or frequency. (Lehto 2009: 40-42). Protection of micro generation has to notice voltage dip tolerance according to IEC 61000-4-11 and EN 61000-3-15 as well as to notice variation in frequency. (Lehto 2009: 43).

LOM protection or anti-islanding protection can be challenging for the micro generation. If the load and the production are near a balance, the protection based on voltage and frequency does not operate and DG remains to feed the islanded grid. Normally the load and production fluctuates, so there appears islanded operation briefly. For secure a successful HSR (normally ≤ 0.5 s), the LOM protection is required to disconnect the DG unit fast enough. The operating time of LOM protection have the same operating time as in U_n -50 %, which means operating time requirement for LOM protection to be 0.15 s. In that case the remaining operating time for successful HSR is only 0.35 s, therefore for definite HSR, the operating time of reclosing can be raised 0.15 s. Equipment manufactures regards ROCOF relays at the moment to be the only reliable solution for LOM protection with set values 0.15 s and 1 df/dt or 1 Hz. (Lehto 2009: 42–43).

The set values for protection devices of DG units according to EN 50438 applied in Finland for class 3b as well as for class 3a and for class 4 DG equipment are enclosed as Appendix 1. In addition the set values for protection device of DG units are defined by Energiateollisuus (2011b), which is applicable for DG equipment below 50 kVA, are enclosed as Appendix 2.

Micro generation may result *false protection functions* in the network, the cases are false trip and delays in protection operation. In false trip situation the micro generation causes an unnecessary disconnection of a certain feeder. The DG unit feeds fault current to the fault location in adjacent feeder in addition to the fault current fed by the network. The fault current fed by the DG unit exceeds the overcurrent protection operation set values of the feeder and unnecessarily disconnects the feeder. Delays for protection functions can be caused by the fault currents fed by a micro generation installation disturbing the operation of network protection. In a fault situation of the feeder, where the DG unit is located, the fault current fed by the DG unit reduces the fault current fed by the network. Therefore the feeder protection will be delayed. (Energiateollisuus 2009: 10–11). Speed of LOM protection can reduce false trips of protection. In addition short circuit currents fed by the DG can have impacts for thermal resistance of devices. This can be resolved by replacing components, dividing the grid into smaller sections, resetting of transformer values or using fault current limiters. (Energiateollisuus 2009: 11).

3.3 Smart energy metering

Energy metering is changing to become more automated. In Finland the legislation (66/2009: Valtioneuvoston asetus sähköntoimituksen selvityksestä ja mittauksesta) requires remotely readable, hourly metering for connection points of 3 x 63 A and over since 2011 and it also requires that 80 % of customers have AMR by 2014. (Esma 2010: 19; Energiateollisuus 2012).

AMR system comprises of an energy meter and communication links to systems of energy suppliers. Advanced metering infrastructure (AMI) refers to a full measurement and collection system that includes smart energy meters, communication networks between the customer and a meter reading system as well as data reception and management systems that make the information available to the service providers.

Remote readable energy meters are divided to either one-way or two-way types. *Smart energy meters* are required to have bi-directional information flow capability, which AMI requires also. Possible functions of smart energy meters are

- measurement of energy,
- measurement of instantaneous power, voltage and current,
- alarms of outages,
- information of voltage and current quality,
- remote connection or disconnection of supply,
- control of loads and
- remote update of meter software. (Sarvaranta 2010).

Energy measurements contain active, reactive, apparent and maximum power per hour. Voltage measurements contain phase, phase-to-phase, voltage symmetry, total harmonic distortion (THD), amplitude of voltage harmonics and under- and over- voltage. Current measurements contain instantaneous, THD and current harmonics amplitude. Instantaneous power measurements contain active, reactive and apparent power per phase and totally. Instantaneous values are obtained of frequency and power factor. Alarms can be obtained of loss of phase voltage (and registration of power supply) and asymmetry of phases. Therefore smart energy meters provide wide information of electricity in connection points at network. Besides of the load control a smart energy meter equipped with a remote controllable switching device can import a lot of new functionalities for control and protection (Löf 2010: 1).

Legislation (66/2009) defines minimum functional requirements of AMI systems, which are remote energy reading, outage registration (over 3 min voltage loss), load controlling, energy measurements and outage data storage as well as protection of data privacy (Valtonen 2009: 26–27).

Smart energy meters are developed towards intelligent devices for different types of measurements and functionalities, which are considered to have a significant role. Finnish interactive customer gateway (INCA) research program defines an interactive customer gateway, which is a logical interface composed of current-using equipment, active devices connected into distribution network, building automation system, communication networks, actors and local control systems. The main functionality for the interactive gateway is the optimization of the power flow at the connection point with references of DGs, controllable loads, ESs and different actors. (Järventausta et. al 2010: 4–6). Functional needs and corresponding functionalities, measurements and controls are defined for customers, transmission system operators (TSOs), DSOs and energy traders. These aspects related to customers are presented in the Table 7 as well as aspects related to DSOs are presented in the Table 8.

Table 7. Customer functional needs and corresponding functionalities, measurements and controls for interactive gateway. (Järventausta et. al 2010: 8).

Customer	Functions	Measurements	Controls
Safety (internal)	Indication and alarming of faults in customer network	Phase current	Opening MCBs
	Identification of islanding	Profiles of voltage and current	Opening the main switch
	Isolating for a faulty network	Leakage current	
	Monitoring of the contact voltage	LOM	
		Harmonics and alarms of exeeding values	
		Flickering and alarms of exeeding values	
		Capacity of controllable resources (instant and 3 min values @ 1 h) : loads, energy storages, indoor and outdoor temperature and others in building	
		Motion detection (usage of a room)	
Uinterruptable use of electricity (internal)	Isolating for a faulty network	LOM	Opening the main switch
	Operation at islanded mode	Capacity of controllable resources (instant and 3 min values @ 1 h) : loads, energy storages, indoor and outdoor temperature and others in building	Priority based control of loads
		Profiles of voltage and current	Charging/Discharging of storages
		Profiles of voltage and current	Appointing of the responsible unit for voltage and frequecy control
		Phase current	Transferring protection responsibility to power converters
		Priorities of loads	
Demand management (internal)	Load pioritisation	Priorities of loads	Priority based control of loads
	Monitoring of power/energy consumption	Energy consumption	Charging/Discharging of storages
	Alarming of high energy price	Input power	
		Capacity of controllable resources (instant and 3 min values @ 1 h) : loads, energy storages, indoor and outdoor temperature and others in building	
		Motion detection (usage of a room)	
Generation management (Internal /External)	Monitoring of voltage and current profiles	Instant value of output power	Priority based control of loads
		Profiles of voltage and current	Charging/Discharging of storages
		Harmonics and alarms of exeeding values	
		Flickering and alarms of exeeding values	
		Priorities of loads	
EV (Internal/ External)	Limiting input energy	Instant value of input power	Priority based control of loads
	Monitoring of charging	Charge level of batteries	Charging/Discharging of storages
	Load pioritisation	Priorities of loads	

Table 8. DSOs functional needs and corresponding functionalities, measurements and controls for interactive gateway. (Järventausta et. al 2010: 9).

DSO	Functions	Measurements	Controls
Demand data management (External/ Intrenal)	Delivery of power measurement data	Energy consumption	
		Capacity of controllable resources (instant and 3 min values @ 1 h) : loads, energy storages, indoor and outdoor temperature and others in building	
Control potential management (Internal/ External)	Delivery of control capacity data	Capacity of controllable resources (instant and 3 min values @ 1 h) : loads, energy storages, indoor and outdoor temperature and others in building	
Load management (External/ Intrenal)	Reception of the transfer price signal	Input power	Priority based control of loads
	Network load modelling	Priorities of loads	Charging/Discharging of storages
	Network load prediction	Capacity of controllable resources (instant and 3 min values @ 1 h) : loads, energy storages, indoor and outdoor temperature and others in building	
	Control capacity modelling		
	Control capacity prediction		
	Limiting of input power		
	Limiting of output power		
Safety and reliability management (External/ Intrenal)	Fault indications and alarms	Profiles of voltage and current	Opening the main switch
	Isolating of the faulty network	LOM	
	Indentification of islanding	Registrations of supply interruptions and voltage dips	
	Maintenance of disturbance records	Contact voltage	
	Monitoring of the contact voltage		
Voltage quality management (internal)	Monitoring of voltage and current profiles	Profiles of voltage and current	
	Fixing the level of voltage	Voltage level, THD, harmonics, flickers (alarms of exceed values)	
	Filtering the voltage distortion	Frequency	

Fast and reliable two-way communication is the basic prerequisite for the flexible interactive customer gateway, which leads towards more strict requirements for communications of smart energy metering too. At present single smart energy meters are red via different telecommunications. Meter reading can be performed either via concentrator or straight from the meter. Usually a meter reading system via concentrator, applies GPRS operating as extension of GSM wireless network between the concentrator (typically in secondary substations or in cable distribution cabinets) and the AMR server. Short Message Services (SMS) can be utilized as confirmation messages. Communication media generally applied between meters and concentrators are Distribution Line Carrier (DLC) and RS cable. In addition meter reading straight from a meter to the AMR server is established by point-to-point (P2P) in 3G network. Wireless mesh (routing and homing network) is used between master and slave meters. (Sarvaranta 2010: 24–25; Sirviö 2011: 30–31). The Figure 27 describes the communication practices between smart energy meters and meter reading system.

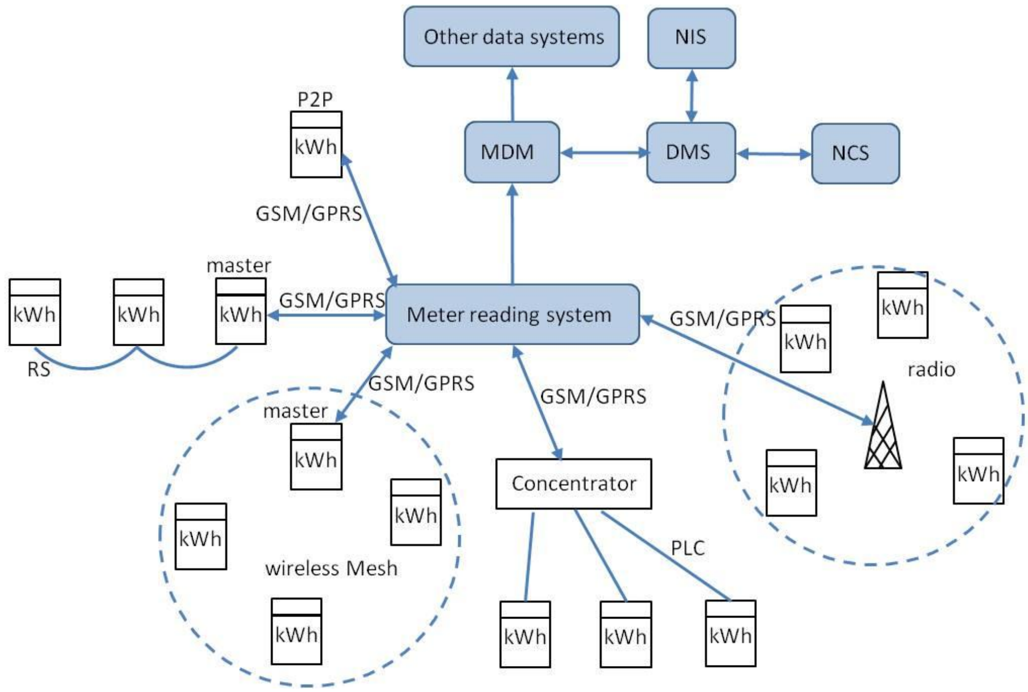

Figure 27. Communication practices between smart energy meters and the meter reading system (Adapted from Energiateollisuus 2010: 26).

Even the DLC data transmission is slow compared to other techniques, the remote reading of hourly energy accordingly to present regulations can be managed with the DLC as well as the data of supply interruptions can be transferred in an hour. When transferring data measured secondly and transmitted within an hour, the DLC would not be feasible anymore because only few meters could be connected to a concentrator. Thus transferring the measurement data in seconds requires faster data transmission than DLC, which would be at least GPRS or 3G. (Valtonen 2009: 58–59).

The integration of AMR systems to DMS is topical, and the main target is to get real-time data to be exploited for outage and quality of electricity management. The integrated AMR-DMS system offers a possibility for load control and improves reliability of electricity supply. Because communications determine the availability of real-time data, transmission by DLC is challenging.

3.4 Electric vehicles

The penetration of EVs is increasing, which has to take into account in the evolution of LV distribution networks as well. In present EVs are either hybrid types using either fuel or electricity for source of energy or pure electricity types using only electricity as source of energy. Impacts to LV distribution networks are considered to be the connection to the network, which changes in the network load amongst other influences. (Järventausta et al. 2010).

Within the INCA research program four interfacing categories for connecting EVs to the national grid were defined, and they are based on possible functionalities of the network-connected EV. The defined interface types are *passive load, dynamic load, vehicle-to-grid (V2G) and vehicle-to-home (V2H)*. The passive load type is interconnected to the distribution network like a typical load without any special control. The dynamic load type can be controlled with specified parameters, but energy supply to the connected network is inaccessible. The V2G type has functions like dynamic load type, but energy supply to the connected network is possible. The V2H type includes a possible function to use vehicle as reserve power for loads at home accordingly to functions of other types. The Table 9 presents the types of EVs and their functions as well as the requirements for connecting to the national grid and the requirements for information and communications technology (ICT) (Järventausta et. al 2010: 30–31).

Table 9. Electrical vehicle types and their functions, requirements for connecting to the national grid and requirements for ICT. (Järventausta et. al 2010: 31).

Type	Functions	Requirements for PCC	Requirements for ICT
Passive load	Charging of power	General requirements for electrical devices intended to use outdoors	-
Dynamic load	Functions included in passive load type		
	Energy measurement of a single EV	A energy measurement device is needed either in EV or in charging station	If energy metering device is placed in a EV, it has to be red remotelly
	Possibility to use charging device as controllable load with means of communication or local control	Frequency measurement and supplementary techniques intended to frequency dependent charging	Communication for load control and monitoring, application depending requirements for communication time response etc.
	Self-diagnosis of the charging device		
	Improving quality of electricity	A charging device applicable for improve quality of electricity	
V2G	Functions included in Dynamic load type		Requirements as for dynamic load type
	Possibility to supply energy to the national grid	Two-way converter included in charging device	Communication needed for discharging operation
		LOM and other protection	
		Securing safety under maintenance of the distribution network	
		Energy meters are required to be capable of two-way energy measurement	
V2H	Functions included in V2G type		
	Possibility to supply energy to a small islanded grid	A disconnector for isolating consumers equipment from the national grid	Automated isolation operation
		Possibility to disconnect loads for securing the power capacity	
		Adequate control and protection features of converter for islanded operation	

For passive load types standards applicable are general requirements for electrical installations as well as standard IEC 61851 and for charging EVs can IEC 61980 be applied as well. For dynamic load types standards for measuring and communications are needed. For V2Gs standards might change, but at present standards applicable are such as connecting DGs to the national grid (chapter 3.2). Standardization for V2Hs does not exist yet, but requirements for the DG operated at islanded mode shall apply. (Järventausta et al. 2010: 32).

3.5 Energy storages

ESs can be used in principle as a reserve power or they can participate to the management of electricity quality. In LV distribution energy storages are used in DG systems as well as in stand-alone systems.

At present ESs are mainly used in uninterruptable power systems (UPS) for reserve power for critical loads in the LOM situation or disturbance of voltage quality. Emergency time is typically rated for 10 to 20 min. (Powerware 2001: 6)

PV and wind power systems including ESs are mostly used for electrification of summer cottages, which are not connected to the national grid (stand-alone systems). Those PV and wind power systems, which are connected to the national grid, have a frequency converter as a connection device. (Andrén 2003: 102; Motiva 2011; Finnwind 2011; Eurosolar 2011).

ESs are examined in this thesis only in centralized power systems with a view to improve quality of electricity. Thus central energy storage at MV/LV substation is intended to be during islanding operation a grid-forming master unit responsible to control the voltage and to maintain the frequency (*Uf*-control) in the LV microgrid (Laaksonen 2011: 39).

4 EVOLUTION PHASES OF LOW VOLTAGE DISTRIBUTION

The evolution of LV distribution networks is considered in this thesis based on the number and functional ability of DG units as well as microgrid features. The evolution phases are studied and defined by way of possible envisaged functions in a LV distribution network and the functions are mainly based on publications of More Microgrids research program by EU. The envisaged functions set operational requirements for the main elements of LV distribution system, which were studied in the previous chapter. The functions are island operation, protection, power quality and demand response amongst others. This chapter describes the evolution of LV distribution networks by four evolution steps, which are traditional, boom of micro generation, microgrid and intelligent microgrid phases.

4.1 Traditional

The traditional low voltage distribution grid corresponds with the present state, where energy flows one-way from the centralized power generation to the consumer-end. Secondary substations are nodal for connecting LV distribution to higher level of electric power networks. In urban areas LV distribution networks are typically open ring types and they are connected to the MV distribution network via a compact or an indoor type of secondary substation. In rural areas the networks are typically radial and they are connected to the MV distribution network via a pole mounted secondary substation.

In the traditional phase of LV networks micro generation is present but few in numbers because majority of customers are not aware of technologies applicable (Schwaegerl et al. 2009: 137) and investments are regarded to be high. DG units operate either separately or parallel with the national grid. In the parallel operation energy flow to the national grid is either blocked or allowed, so applicable DG units are classes 1, 2 and 3. DSOs adopt “fit and forget” philosophy when connecting DG equipment to the distribution network (Schwaegerl et al. 2009: 137). Microgrids are in infancy and under development, in which case different types of pilot projects of microgrids come up.

The main functions in this phase are energy delivery to customers and metering of consumed energy. In addition the functions provided by a smart energy metering device; load control and indication of the lack of supply, is adopted. The protection of the distribution network is implemented by traditional manual operated fuse based devices from MV/LV substation feeder down to the main protection of customers.

An example of a LV distribution network in the traditional phase is presented in the Figure 28. The figure illustrates the main components of the network in a sub urban area. There are residential consumers 30 connected to the CSS. The CSS is equipped with an 800 kVA transformer in order to cover future needs, observing the area available to build new houses. The protection system is fuse based as described in the chapter 3.1. Customers are connected to the national grid with 3 x 25 A line connection, so that maximum power supplied is about 17 kVA. The most of consumers use electricity for heating, because the investments for geothermal energy system are still relatively high. One customer has a class 3b PV system operating parallel with the national grid. The second customer has class 3b PV and wind power generation connected to the national grid. Because customers have mostly direct electricity heating system, the amount micro generation will increase in future.

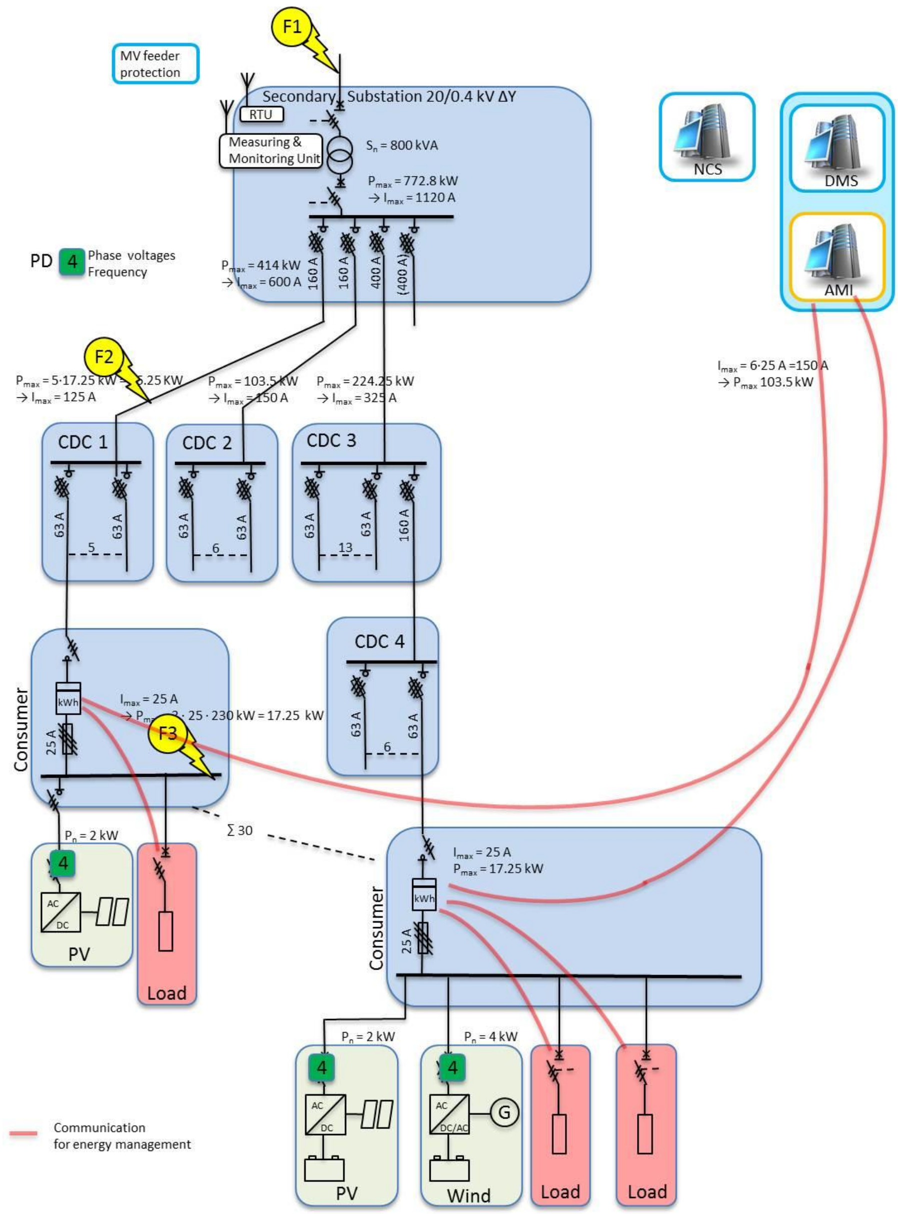

Figure 28. An example of a LV distribution network in a sub urban area at present or at phase 1 of evolution.

4.2 Boom of distributed generation

This evolution phase boost the use of local or regional RES in electricity and in heating increasingly aiming to self-sufficiency in energy. In addition to the customers' equipment, RESs are integrated to the regional infrastructure, which means RES units can be connected to the connection point of customer or directly to the MV/LV substation. Micro generation units and micro power plants are located near to the consumption point producing energy primarily to own use. Small-scale production, for example a CHP unit, is feasible to be located near to the secondary substation. Energy feeding to national grid is occasional and slight, or it can be prevented.

The increased number of DG units challenges protection issues of the LV distribution network and therefore DSOs begin to concentrate more precise on impacts of DGs. Short circuit levels increases near DG, which affects to the requirements for the endurance of devices (Lehto 2009: 48). Challenging are the directly connected asynchronous generators, which can supply short circuit current peak value $6 \cdot I_n$ (Ylä-Outinen 2011: 19). For preventing the increase of short circuit levels in the LV distribution grid, it could be divided into smaller parts, but quality of voltage may suffer (Mäki 2007). In some cases fault currents can decrease, because DG units, which are connected to the grid by means of power electronics (inverters) are capable to feed the fault current only about 2–3 times I_n causing delays in the operation of the protection system (Ylä-Outinen 2011: 19–20; Lehto 2009: 48). In this case the traditional fuse protection can be critical with the operation time in addition to a fault situation, where the voltage of grid decreases so much that the LOM protection operates before the grid protection. These kinds of challenges have to be considered carefully when planning the protection of the LV grid. At least the protection of the main supply has to be checked before connecting the DG unit to the national grid, which means relay settings or fuse parameters. With right set values the false functions of protection can be prevented. (Ylä-Outinen 2011: 20).

Active management is desired to restrain costs of the network upgrading. For managing energy consumption wisely, a DSM system is adopted through smart metering, which controls the passive loads centrally. The loads to be controlled are mostly heating systems and passive or dynamic load type of EVs.

Secondly local commercial VPPs can appear when local generation closes up to consumption or sometimes exceeds. A VPP is a cluster of DG installations, which are controlled centrally. The VPP includes backup power supply, which reacts quickly to fluctuations in energy. Power is purchased and delivered to agreed nodes and it adopts the structure of internet-like model, therefore VPPs are called as Internet of energy. The VPP system is enabled by advanced power electronics (inverters) and efficient central ES communicating to the central control system in real-time.

The Figure 29 presents an example of a LV distribution network in the boom of DG phase. The network is the same as in traditional phase, but developed further. The number of micro generation at customers is increased as well as a local small-scale production unit, CHP equipment, is installed beside the CSS. Micro-generation at customers is PVs and wind turbines, which are class 1, 2 or 3 equipment. The CHP unit is a small-scale production unit, which is class 4 equipment. The CHP unit is connected to the LV feeder with 3 x 200 A protection device, thus the requirement for compensation of reactive power is avoided (Helen 2009). The protection of the distribution network is implemented with traditional fuse based system from the LV feeder at CSS to the customer main protection. Load control is implemented by smart energy meter referred to heating loads. At the same time some DG units are controlled locally by smart energy meters as described in the Chapter 3.2.1 (class 3a). A system for energy management or local DSM could be feasible to control micro-generation units and loads at customers. Smart energy meter could monitor the amount of generation and consumption and further send control commands to the consumer devices as well as to the consumer feeders where to loads are connected.

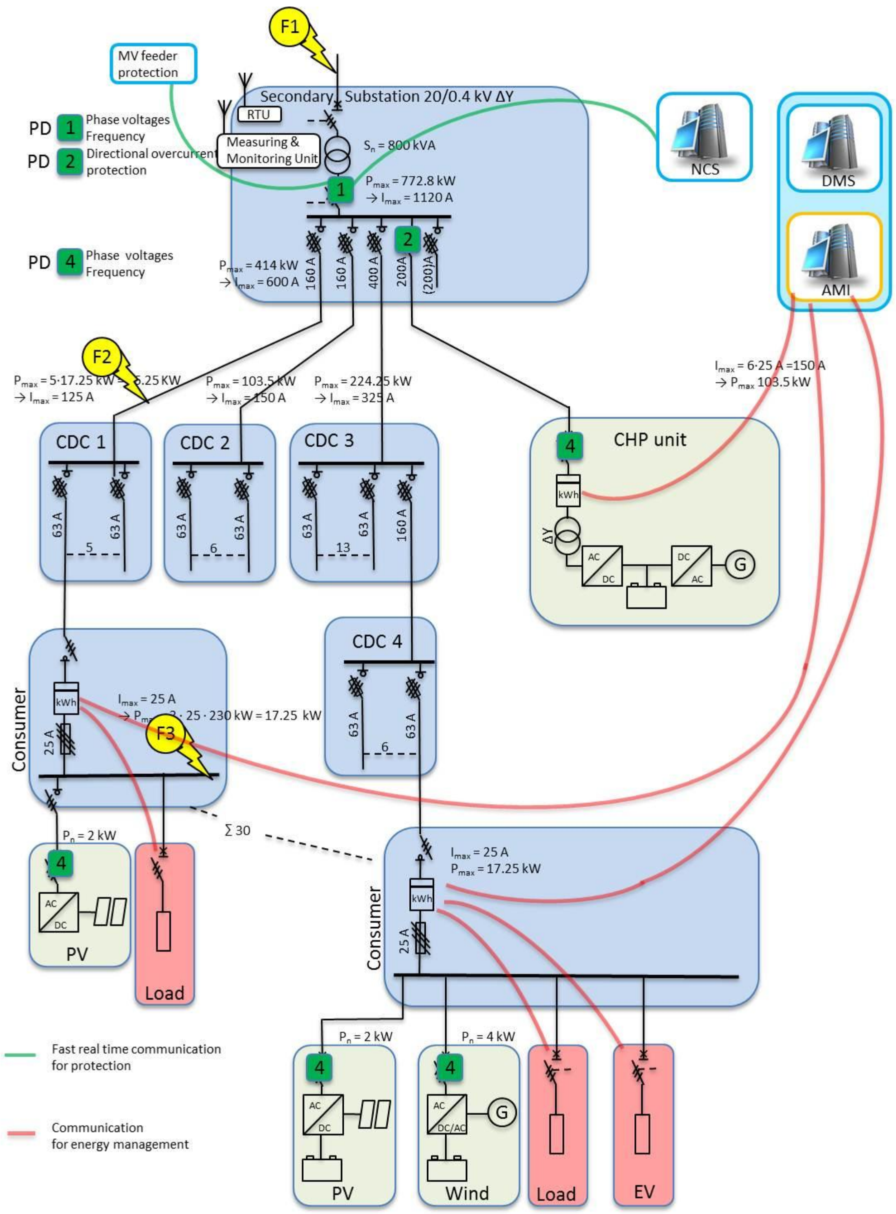

Figure 29. An example of a LV distribution network in a sub urban area at the boom of DG or at the phase 2 of evolution.

The boom of micro and small-scale generation is a certain phase of challenges, because of the complexity to validate a reliable and selective protection system in every fault situation. In addition the management of voltage levels and quality of electricity is challenging without coordinated control. At least these two issues question the convenience of passive LV distribution networks without a central control system, which operates based on local measurements only.

4.3 Microgrid

In microgrid phase customers will become more active by smart energy meters and controllable loads as well as the number of EVs and ESs will increase. The LV network bears the use of ESs and backup power generators in addition to the local or regional renewable power generation. The load control is implemented by smart energy meters. The grid is normally connected to the national grid, but the island operation mode is possible, for example, in the lack of main supply. Large scale integration of DERs and grid capability for island operation will require a new concept for safety and operation management. The microgrid concept is seen to be the most adequate.

The Figure 30 illustrates the main operations of a microgrid. In normal situation the microgrid operates in parallel with the utility grid. In consequence of a fault in the feeding MV line, the operation changes to islanded mode automatically. However, the islanded mode can be purposely controlled by NCS, for example, because of maintenance work. Reconnecting the microgrid to operate parallel with the utility grid occurs synchronized.

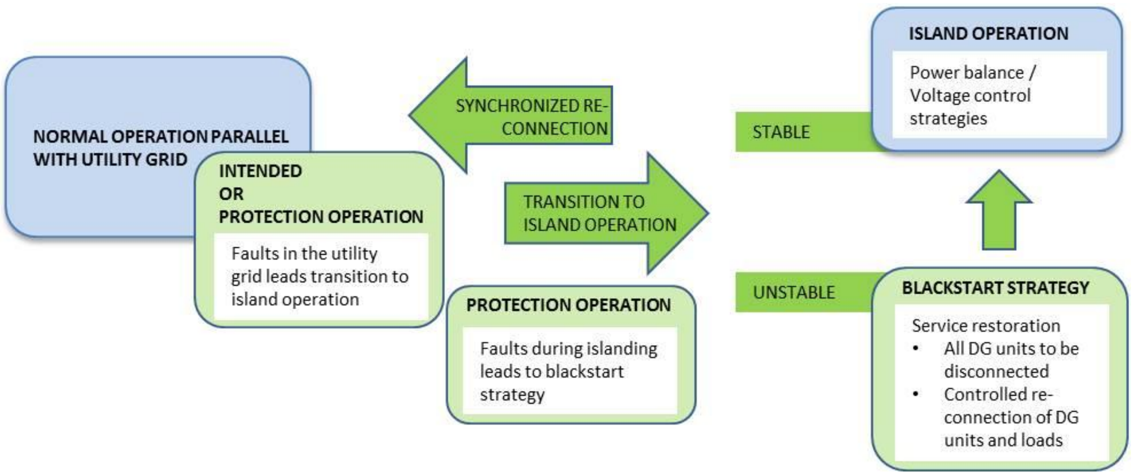

Figure 30. The main operation strategies of a microgrid. (Adapted form Laaksonen 2011: 25).

Microgrid interconnection switches are essential during transition from the grid connected mode to the islanded mode. The interconnection switch changes the operation mode from islanded to grid connected mode after the microgrid and the national grid are synchronized in voltage and frequency. For the stable operation during transition, a fast operating interconnection switch is required, which is located in the connection point of the national grid and the formed microgrid. In practice the interconnection switch is located in the secondary substation. (Kroposki et al. 2008).

In addition ESs are needed for managing the island operation successfully, because the island operation causes challenges for power balance and voltage control, but can be stabilized with centralized ESs. Distributed ESs are also valuable for stabilizing DG units to produce constant output energy despite load fluctuations as well as they are valuable for improving fault-ride-through (FRT) capability. Different technologies are applied like batteries, super capacitors and flywheels. (Kroposki et al. 2008).

The most of DG units are connected to the national network via converters. The converters can be AC/DC–DC/AC type or DC/AC type. The converter contains output filters and protection functions for the DG unit and for the LV network. (Katiraei et al. 2008; Kroposki et al. 2008).

EVs will cause influences for the voltage profile, losses and power quality to the connected distribution network (Deilami et al. 2010; Moses et al. 2010). Large amount of EVs will increase the need of active voltage control as well as controllable loads by EVs are needed to be included in the voltage control system (Laaksonen 2011: 29).

Control strategies for DER units are based on the voltage and frequency control as well as on the active and reactive power control. The control functions of a DER unit can be either a grid-following or a grid-forming type. A grid-forming master unit can regulate the voltage and can set the frequency in the network. The role of a grid-forming ES is very important for the safety and protection as well for the operation management of microgrids. Also the location in the network has high impact for the control (Laaksonen 2011: 23–24). A grid following unit controls the active and reactive power. (Katiraei et al. 2008).

The time synchronization of all DER units and protection devices is crucial to the operation of microgrids. Therefore a time synchronization mechanism must exist and all information exchange should include time stamps for exact report sequencing and for logging history data. Communication protocol standards like IEC 61850 offering a control model mechanism called generic object oriented substation events (GOOSE) and extension of event transfer mechanism called generic substation state events (GSSE) can be used for the time and safety critical communications. (Strauss 2009: 102). A specific management system is required for ensuring reasonable control and coordination between devices, the equipment and the subsystems of a microgrid. A microgrid management system (MMS) could be located at the secondary substations or could be integrated to the microgrid interconnection switch. (Laaksonen & Kauhaniemi 2008).

The basic characteristics for the MMS are (Laaksonen 2011: 24):

- Two-way communication with DMS in real time, ES, microgrid interconnection switch and protective devices
- Information exchange with DG units and loads including measured parameters, status data and control commands
- Intelligence and adaptability like built-in strategies for different possible operations

Information flow of the MMS includes mainly (Laaksonen 2011: 25):

- Information stored and received
    - Technical parameters of DG units, loads and local ESs
    - Status data of units
    - Information from DMS
    - Measurements
    - Protection settings
- Information sent
    - Set-point values (*P* and *Q*) for DG units and ESs
    - Information for DG units about the transfer to the island operation or back to the normal operation
    - Connection or disconnection commands for loads, DG units and ESs
    - Tripping commands for protective devices

4.3.1 Power balance management

The power production and consumption is balanced in LV microgrids with DERs, which are coordinated by MMS. The power balance management comprises of the configuration of central ES units, the categorization of customer loads as well as customer DERs. Utilization of DSM for the power balance management requires the smart metering and the smart control of loads to be adopted fully, which mean that the smart energy meters or customers' household management systems should be capable for load control. In addition fast disconnection of loads will require high-speed communications during the island operation. (Laaksonen 2011: 76–77).

4.3.2 Voltage control

The increased number of DG units and EVs increase variations of the voltage. For managing the variations actively, either the off-load tap changer has to be changed to OLTC (Oates et al. 2007; Awad et al. 2008) or the central ES should be capable to manage the level of voltage (Laaksonen 2011: 79). The LV microgrid could participate in the voltage control of the MV feeder by coordinated management of the central ES, controllable DERs and controllable loads by MMS (Laaksonen 2011: 79).

Based on simulations made by Laaksonen (2011), the central ES unit participating to the active control of the MV feeder was proved to be an effective and more precise solution compared to the OLTC when controlling the level of voltage. During the normal operation of the LV network, the central ES could be used for voltage level control and for power flow management (Laaksonen 2011: 79).

Due to the single phase loads or the single phase power generation, voltage unbalance will appear in the microgrid under islanded operation. Unbalanced voltages may cause oscillations in the active and in the reactive power of the DG units. The unbalance of voltage should be managed by controlling single-phase DG units, ESs, EVs and controllable loads, which are coordinated by MMS. (Laaksonen 2011: 83–84). The compensation method for voltage unbalance in the islanded operation of the microgrid has to be compatible with the protection (principles and settings), the level of voltage and the

THD management of voltage as well as re-synchronization functions (Laaksonen 2011: 84).

Laaksonen (2011) proposes a hierarchical voltage control scheme for Smart Grids, where an active central ES unit has the prior role. The central ES is responsible for feeding or absorbing of reactive power as well as absorbing of active power. An example of hierarchical voltage control of LV network with utilization of active central ESs is presented in the Figure 31.

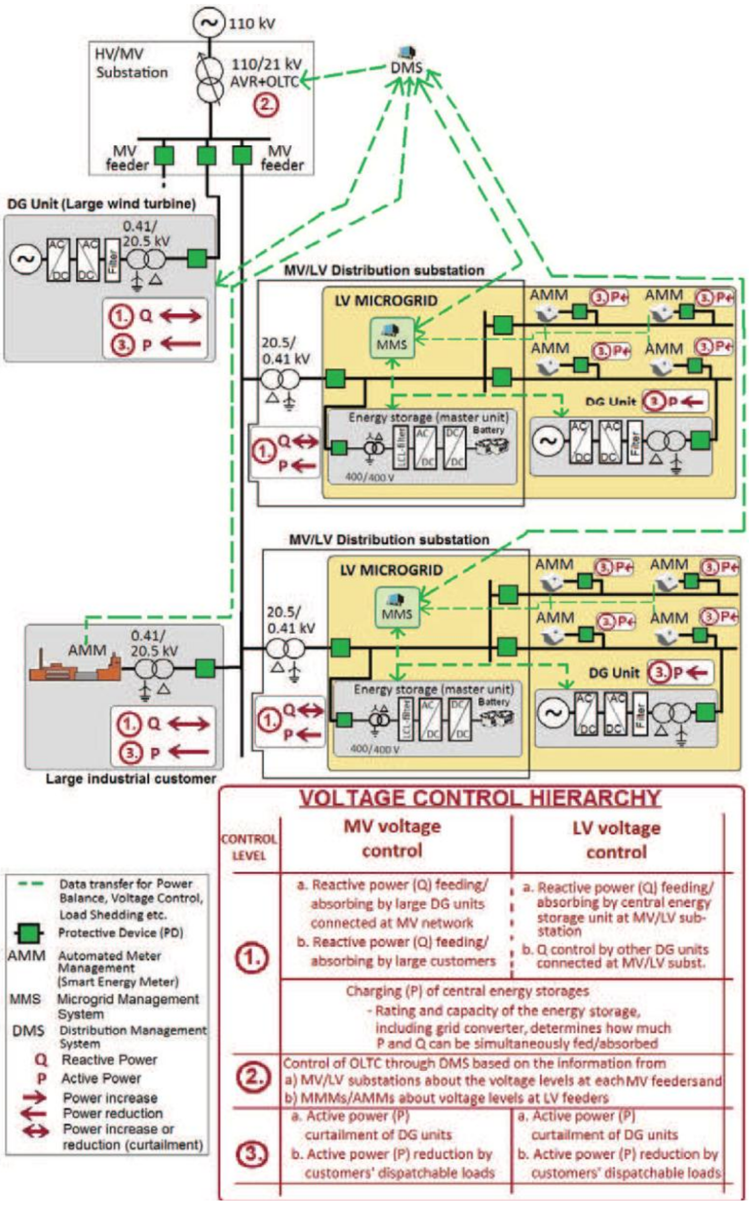

Figure 31. A voltage control scheme for Smart Grids. (Laaksonen 2011: 89).

4.3.3 Protection

Microgrids require a protection system, which is reliable when microgrid operates in parallel with the national grid as well as when it operates in the island mode. Traditionally in radial distribution networks, the protection system is based on high fault current levels and therefore the fuse based protection is very suitable. Instead in microgrids the fault currents under islanded operation are mostly fed by converter connected DER units, which have limited short circuit feeding capabilities. Therefore the traditional fuse-based OC protection would not guarantee safe and selective protection enough for the microgrid. (Laaksonen 2011: 92).

An adaptive protection system is required, which should be economically feasible and simple. Technical requirements for implementing an adaptive protection system are proposed by Oudalov et al. (2009) as follows:

- Numerical relays or IEDs with the overcurrent protection function for managing bi-directional power flow instead of the traditional fuses.
- Several setting groups to be activated or deactivated locally or remotely, manually or automatically.
- Centralized or decentralized communications between protection devices (PDs)
- Real-time information about the topology of the network, status of DERs, charge state of ES systems as well as the number and the size of grid connected loads is needed for protection and control functions of IEDs.

Laaksonen (2011) propose a smart protection system for LV microgrids, which demonstrate the number of protection zones, protection principles for parallel and island operated microgrid as well as speed requirements for the protection. The Figure 32 presents an illustration of protection zones and protective devices of the proposed protection system. The number of selected protection zones affect to the number of PDs. The PDs are classified as (Laaksonen 2011: 95):

- “PD 1: Microgrid interconnection switch including relay and circuit-breaker or fast static-semiconductor-switch (SS)

- PD 2: LV feeder protection including relay and circuit-breaker or static-switch (SS)
- PD 3: Customer protection including fuse or low voltage-/miniature- circuit-breaker (LVCB/MCB) or in case of very sensitive customers, LV customer microgrid (DC or AC) with SS may be needed
- PD 4: DER unit protection”

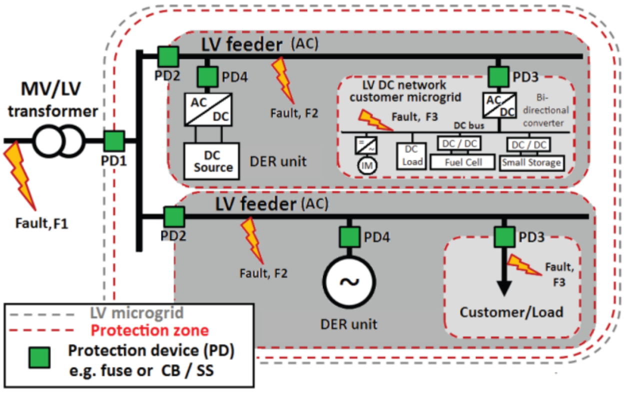

Figure 32. The number of protection zones and devices in LV microgrid (Laaksonen 2011: 95).

Protection principles are required to be defined for both the parallel as well as the islanded operation of the microgrid. In addition protection in the mode of transition to island operation due to a fault in MV (fault F1) or faults in the LV network has to be considered. The protection system of LV microgrids is required to operate rapidly in all fault types, because directly connected rotating machines loose stability in voltage dips easily and they jeopardize the stability of the whole microgrid under island operation.

DG units have an essential role in the protection system, because the control principle of a converter of the DG unit has the main impact on fault detection in island operated microgrids (Brucoli & Green 2007). The DG unit converter must feed fault current at least its rated current as well as the unit is not allowed to be disconnected before the protection of microgrid has operated (Laaksonen 2011: 97). Therefore in the island operation of microgrids, the protection system is proposed to be based on voltage, because of the lack of high fault currents (Laaksonen & Kauhaniemi 2007; Al-Nasseri & Redfern 2007). In addition selective protection of microgrids is difficult to realize by a protection system with voltage or current relays alone (Oudalov & Fidigatti 2008). Altogether structural choices of microgrids determine largely the technical choices of the protection system (Laaksonen 2011: 97) and the speed requirements are divided by structural choices of:

- Required technology for switching devices,
- Required communication technology and
- Required capacity of the central ES.

Oscillations caused by change of microgrid configurations might affect to protection. For avoiding unnecessary tripping of PDs and for achieving selective protection, communication based interlocking signals is feasible to be utilized. Thus real-time communication is needed between the PD1 and PD2s, between the master ES unit and DER units as well as between the MMS and all microgrid components including customer loads.

Functionalities required for PDs are presented in the Figure 33. Microgrids' transition from normal to island operation requires for the MMS to send a state-change signal to all PDs involved because of the adaptation. Thereafter the microgrid interconnection switch PD1 is ready for synchronized re-connection by measuring the phase voltages at the utility grid side as well as at the microgrid side. Transition from island to normal operation requires for MMS to send a state-changed signal to PD2s and PD4s. In addition the MMS manages power balance in the island operation, which means for example sending new set point values to DER units after a fault situation in the islanded microgrid. (Laaksonen 2011: 98).

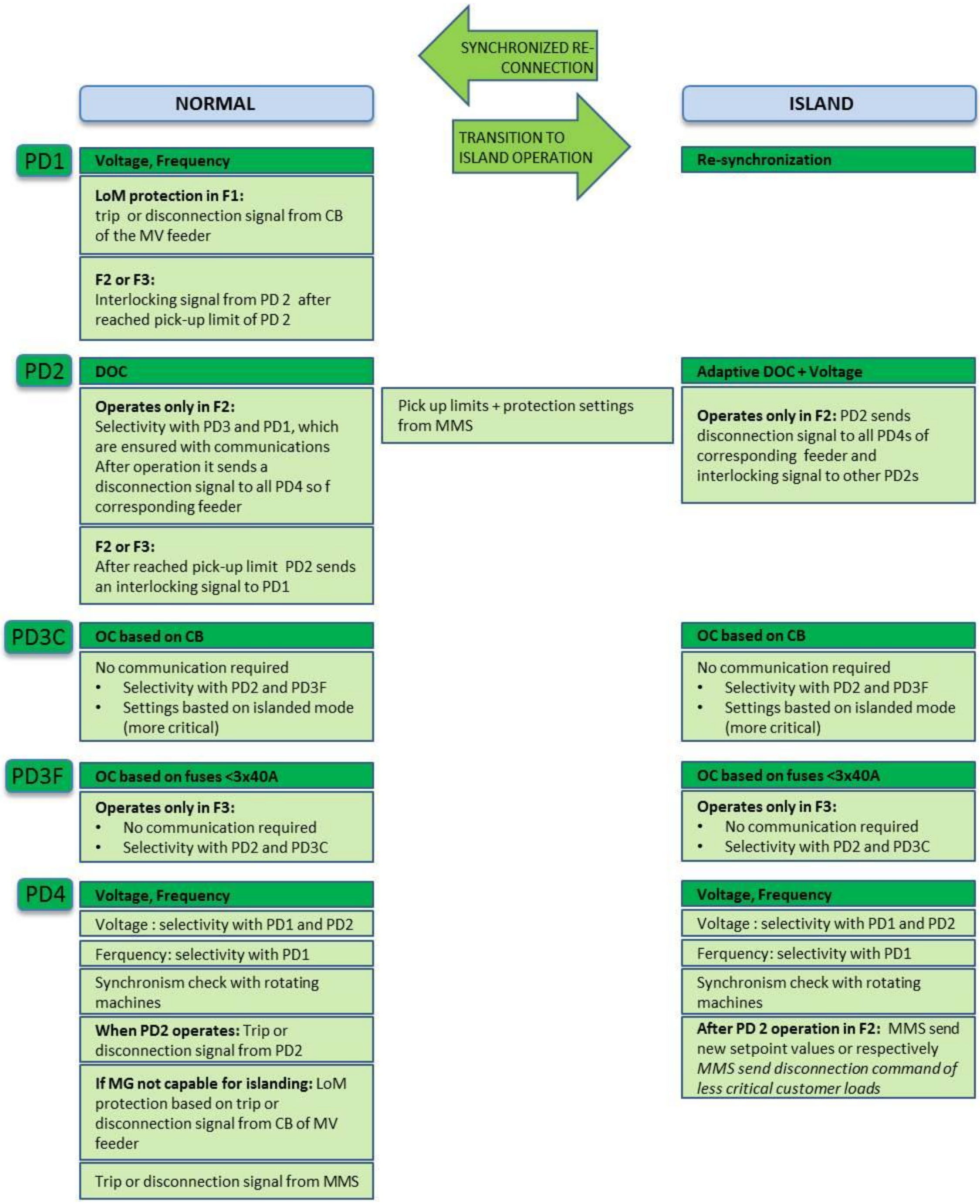

Figure 33. Functions in the normal and in the island operation of microgrid. (Adapted from Laaksonen 2011: 100).

Operation curves for the voltage relay of PD1 in normal operation as well for the PD4 in the normal and the island operation are presented in the Figure 34.

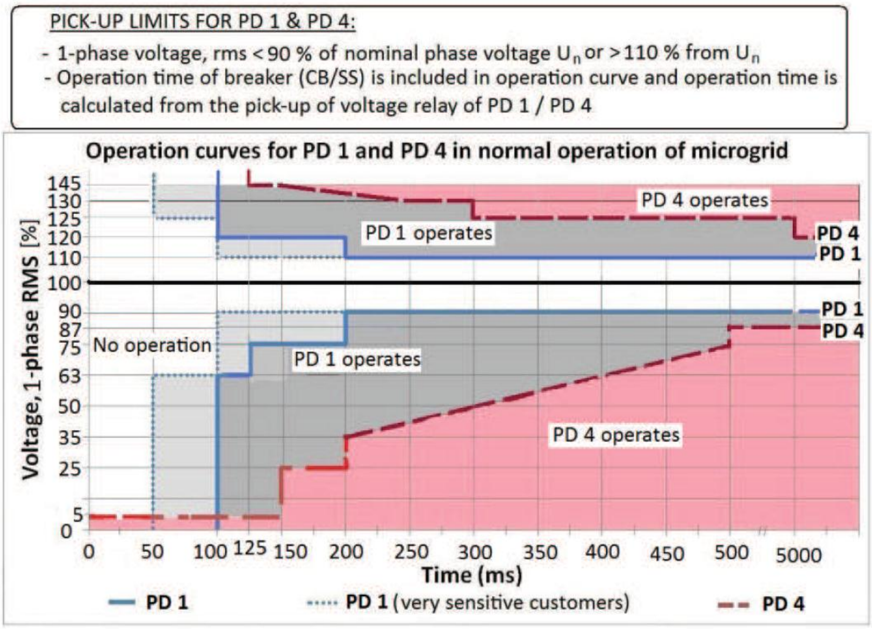

Figure 34. Operation curves for voltage relays of PD1 and PD4. (Laaksonen 2011: 102).

Operation curves for frequency relays of the PD1 and the PD4 in normal and island operation are presented in the Figure 35.

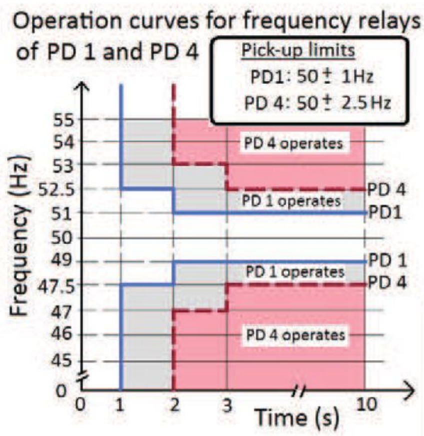

Figure 35. Operation curves for frequency relays of the PD1 and the PD4. (Laaksonen 2011: 102).

Operation curves for overcurrent relay of PD2s in the normal operation and for overcurrent relay of PD3s in the normal and the island operation are presented in the Figure 36. The figure shows that the time delay between PD2s and PD3a or PD3C is small and therefore the selectivity is hard to achieve without interlocking signals based on communication. (Laaksonen 2011: 102–103).

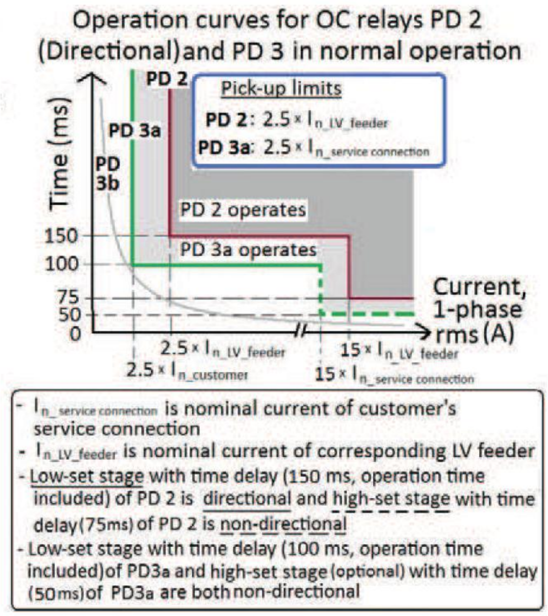

Figure 36. Operation curves for overcurrent relays of the PD2 and the PD3. (Laaksonen 2011: 102).

The operations of PD4s have to be time-selective with other PDs for avoiding unnecessary disconnections of DER units. The main point of protection in LV microgrids during island operation is the algorithm of PD2s, so an adaptive multi criteria algorithm is developed by Laaksonen & Kauhaniemi (2010). During island operation the number and types of DG units as well as their capability to feed fault current are included into the multi-criteria algorithm of the PD2s. The algorithm is based on measurements of voltage and current. Therefore high-speed communication is required between PD2s to guarantee fast and selective protection enough. The set values for PD3s and PD4s remains the same in island operation as in normal operation. A time delay is proposed for PD2s, for example, to guarantee stability after a fault. A PD2 has to send an interlocking signal to other PD2s after exceed pick-up limits for voltage values and directional overcurrent values. (Laaksonen 2011: 101–104).

Large DG units with high fault current feeding capacity should be connected directly or via own feeder to the secondary substation for achieving selective protection during the island operation. The large units are also beneficial to connect directly to the secondary substation so that the unit would remain connected into grid in fault situations for feeding the fault current. (Laaksonen 2011: 108).

The proposed protection system requires fast operating, accurate and programmable PDs, which are capable for high-speed communication. This means the traditional fusible devices are not applicable for microgrids (Laaksonen 2011: 108). Laaksonen proposes a new kind of the PD or a Smart Grid Switch (SGS) based on CB or semiconductor technology, which would achieve the requirements for rapid response. In addition the most sensible option would be that a SGS with IEC 61850 communication capability should be utilized as PD1, PD2 and PD4. (Laaksonen 2011: 108–109).

4.3.4 Structure

The Figure 37 presents the exemplary LV distribution network developed to the microgrid phase. A central ES unit is located in the CSS, but ESs integrated in DER units are ignored. The power balance management, voltage control as well as the protection system are implemented by above-mentioned concepts. Hence the protection algorithm is multi-criteria and based on voltage and current measurements. The protection algorithm of PD2 is adaptable with the network configuration and states of DER units during island operation. The MMS manages the adaptation by changing settings and pick-up the limits of PD2s according to the configuration of microgrid. Different communication ends and paths, which are required for these different systems, are presented in the figure also. In addition the isolating devices of the DG units are feasible to be remote controllable and lockable in this phase of evolution to ease maintenance work in the network, so the control of the disconnectors is feasible to implement by MMS.

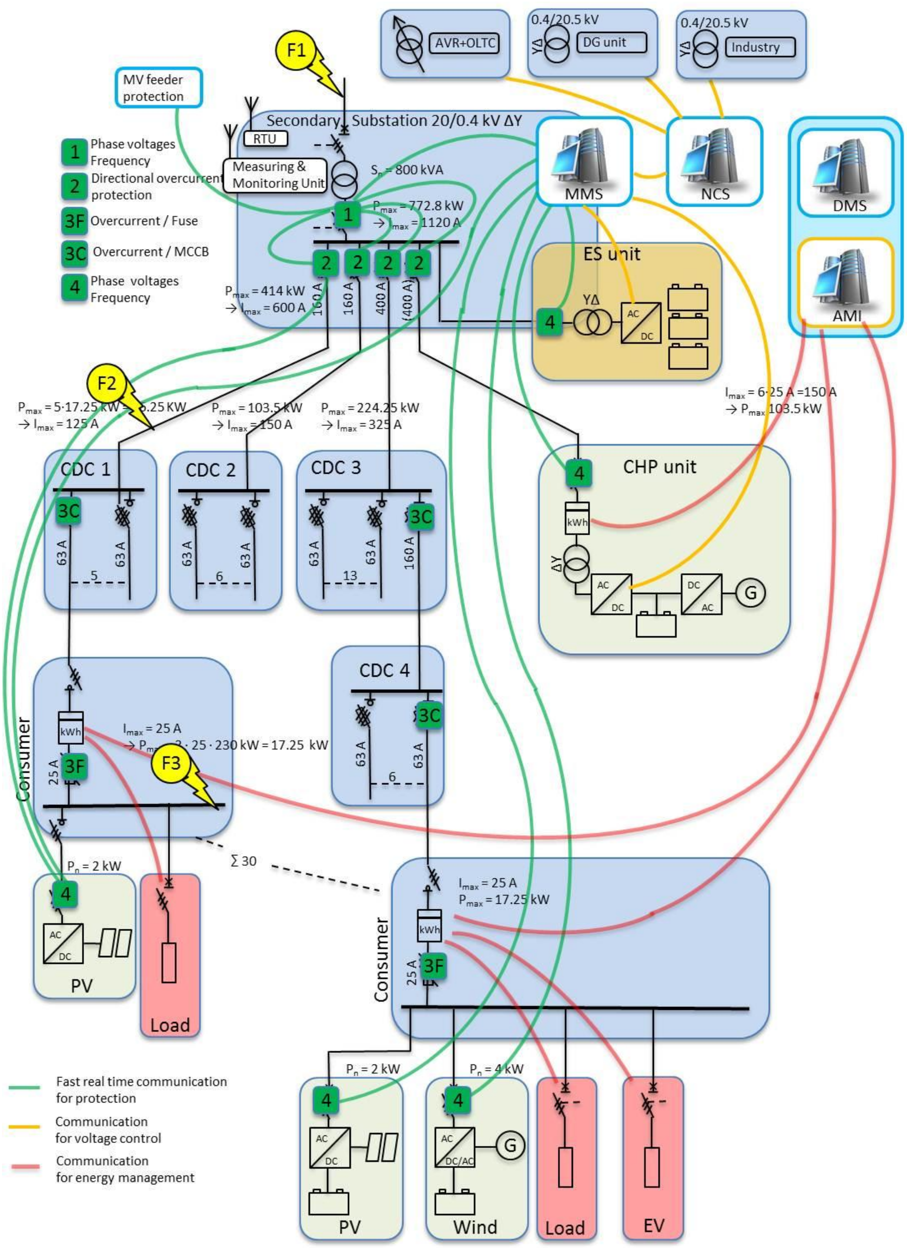

Figure 37. An example of a LV distribution network in a sub urban area at microgrid or at phase 3 of evolution.

4.4 Intelligent microgrid

The major relationships that are developing across the Smart Grid domains are presented in the Figure 38. The conceptual model describes the different actors and possible communication paths. Also potential interactions of intra- and inter domains are identified as well as the potential applications enabled by these interactions. The core of developing architectures for Smart Grids can be analysed by a view of the types of interaction development. (NIST 2012: 43).

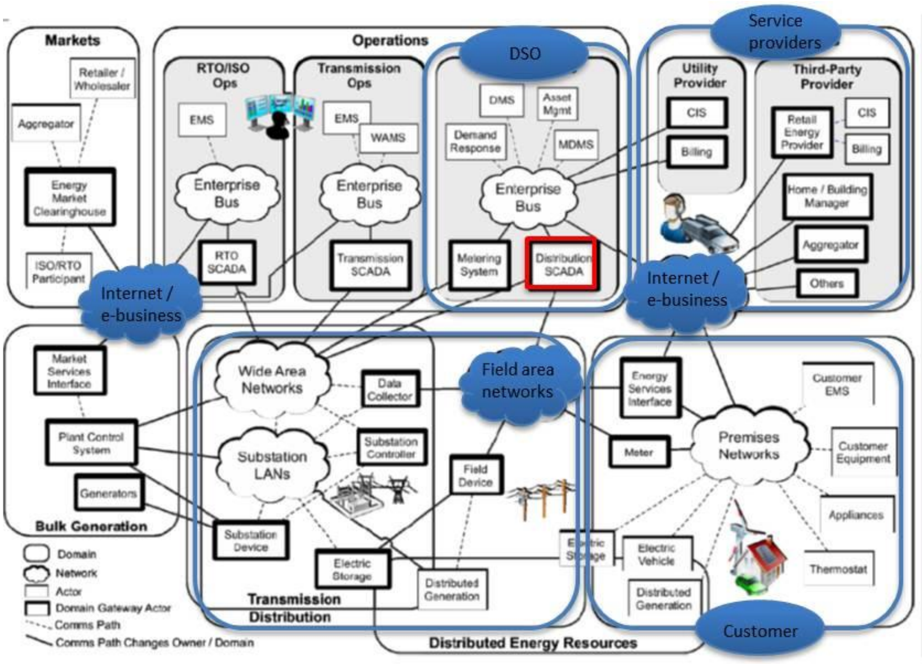

Figure 38. Conceptual Reference Diagram for Smart Grid Information Networks. (NIST 2012: 43).

Intelligent microgrids are operated as integrated energy systems where electricity and heating are managed as integrated energy vectors of multiple energy systems and distributed multi-generation. Operational benefits of intelligent microgrids arise from the integrated management of multiple energy vectors. The flexibility is the major benefit of intelligent microgrids, but new models are required for design of electricity networks to be integrated to other energy systems (Mancarella & Pudjianto 2009: 116–118).

Renewable DG, like wind and solar is envisaged to exceed 15 % of total average generation and over 5 % of all customers will have a small-scale generation deployed in their premises. DG has a great impact on the market price and in addition the management of power balance and price signals are seen and reacted in real-time by all the participants in the market. DSM is widely applied by the DSOs. (Parkkinen & Järventausta 2012: 26)

LV distribution networks are completely smart in the intelligent microgrid phase. Different methodologies are referred for operation strategies of microgrids. The operation strategy can be chosen flexibly from *economical, technical, environmental or combined modes*. Different stakeholders like DSOs, DG owners, DG operators, energy supplier and customers are involved in scheduling of the optimal production. (Mancarella & Pudjianto 2009: 116; Schwaegerl et al. 2009: 63–65).

The Figure 39 illustrates operation strategies of microgrid. In the economic operation mode DGs are operated with full liberty and the main limitations are constrains of DG units, which are energy balance and the physical limits. In the technical operation mode, the production costs and revenues of DGs are ignored and DSOs have complete control over operation of DGs. The operation is optimized by basis of the network, which include minimizing of power losses, voltage variation and device loadings. In the environmental operation mode only the amount of emission determines the operation of DGs, so the financial as well as the technical aspects are not valuable. In the combined operation mode all of the foregoing factors are recognized so the technical and the environmental criteria are converted to the economic equivalents, when both the grid and DGs are constrains for the optimization. (Schwaegerl et al. 2009: 63–65).

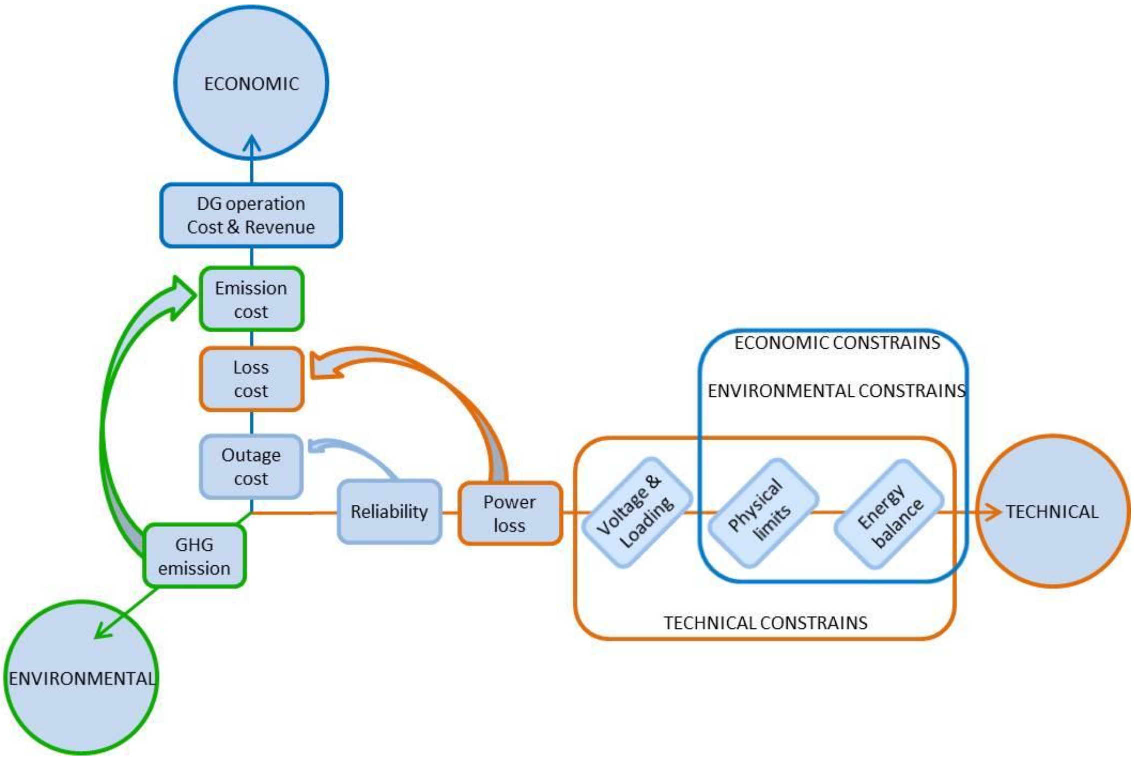

Figure 39. Microgrid operation strategies. (Schwaegerl et al. 2009: 63–65).

Power balance management is realized by configuring central ES units, categorizing of customer loads more specifically than basic heating load as well as controlling customer DERs. The power balance and the configuration can be modified for different needs. Regional requirements are needed for power balance management and for power quality (Parkkinen & Järventausta 2012: 29).

ESs could be owned by a third party instead of a DSO. The third parties can participate in energy markets by active power production or discharging the ESs and by active voltage control through *local technical service markets.* Customers in the LV distribution network can participate in the technical service markets by allowing to control the loads like water heaters and electrical heating as well as to control the charging of EVs. (Laaksonen 2011: 90).

New buildings are zero energy buildings with own production as well as a home energy management or an automation system is a standard equipment. Customers can have local ESs for guarantee UPS. Heating loads are controlled directly by retails in residential buildings. The amount of heat pumps increases, which will respond to process of electricity. Customers use DR services and products widely as well as they buy customized services of energy efficiency on large scale. (Parkkinen & Järventausta 2012: 22–25).

All four interfacing categories (chapter 3.4) for connecting EV to the national grid appear and the batteries of EVs are used as ESs or sources in the grid flexibly (Parkkinen & Järventausta 2012: 12). The most challenging is V2H type, which is capable for supply energy to a small islanded grid like customer installation or home. The V2H type requires a LOM protection device, control and protection features of converters for island operation as well as a device for automated isolation.

Smart energy meters are accessible to provide data for ancillary services, but in addition the MMS could offer data and controllability to different actors for achieving more enhanced services in real-time.

Fault locating, isolation and restoration are fully automated without the control room intervention (Parkkinen & Järventausta 2012: 11). The protection system is based on zone concept like in microgrids phase, but implemented further. Long radial LV feeders as well as open ring LV distribution systems are reasonable to divide into more deeper the protection zones.

The Figure 40 presents the studied LV distribution network in the intelligent microgrid phase. The network is divided into protection zones in more details, so by closing normally open PD5 in a fault situation when PD2 acts, the number of affected customers can be reduced. The PD2 sends a closing signal to PD5 and interlocking signal to other PD2s in a fault situation between the PD2 and the PD3C. In a fault situation after the PD3C, the PD2 and the PD3C detect the fault simultaneously and therefore PD3C have to send an interlocking signal to the PD2 for achieving selectivity. (Laaksonen 2011: 106–107).

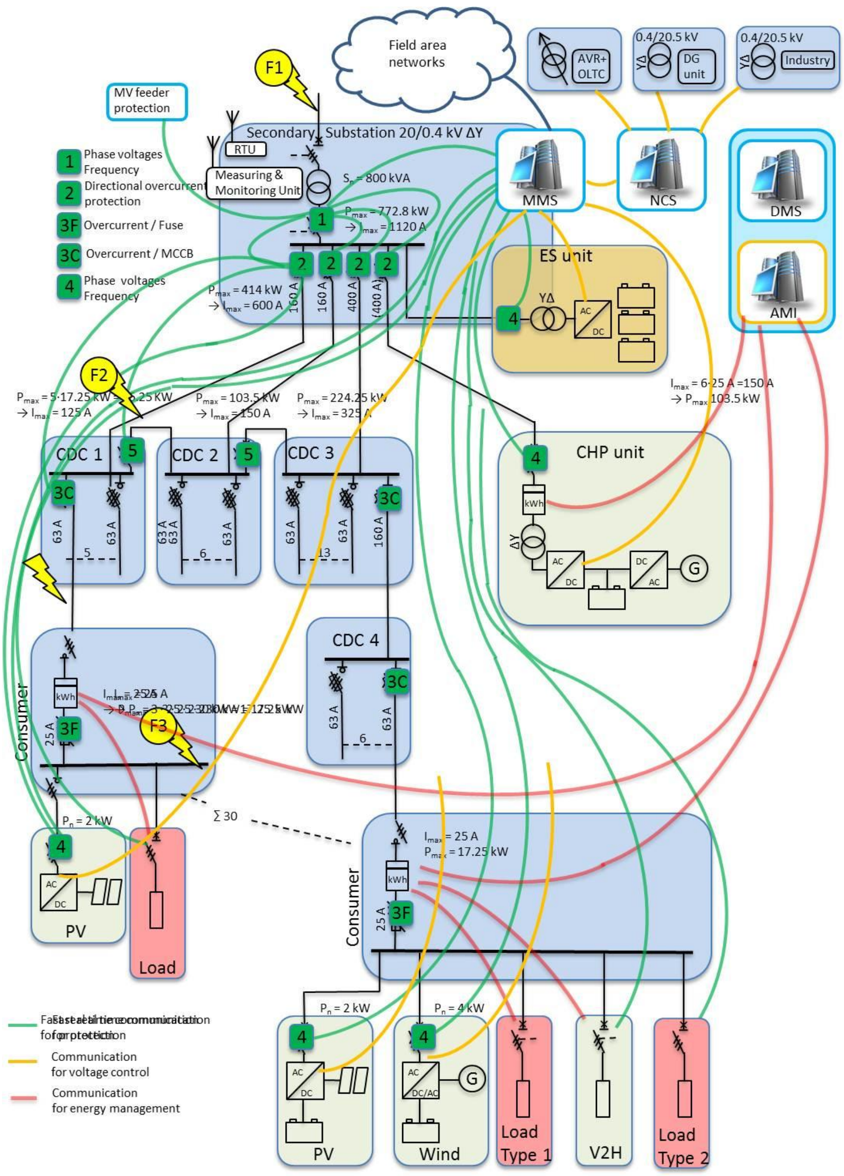

Figure 40. An example of a LV distribution network in a sub urban area at evolution stage 4 or Intelligent Microgrid.

4.5 Summary

LV distribution networks in the evolution phase 1 and 2 have a simple management system in which protective devices operate based on local measurements and no communication is utilized between them. The phases 3 and 4 have a kind of centralized management system located in the secondary substation called MMS. The main functions of the

MMS are the control of microgrid in normal and in island operation as well as in transitions including functions of protection, voltage management and energy balance.

Tables 10 and 11 summarize the main characteristics of the devices and equipment, which are required in different evolution phases of LV distribution networks.

Table 10. Main characteristics of protective devices in LV distribution networks under evolution phases.

Node		Traditional	Boom of Microgeneration	Microgrid	Intelligent Microgrid
PD1	Device type	Switch disconnector	Switch disconnector	Microgrid interconnection switch including relay and circuit breaker or fast static-semiconductor-switch (SS)	Microgrid interconnection switch including relay and circuit breaker or fast static-semiconductor-switch (SS)
	Operation	Manual	Manual or remote control	Remote control, local measurements	Remote control, local measurements
	Main operation functions	Isolating the LV network	Isolating the LV network	Isolating for a faulty network in F1	Isolating for a faulty network in F1
	Communications	No communication	Possible to RTU at CSS	NCS, MMS	Communications to NCS, MMS
PD2	Device type	Switch fuse	Switch fuse, fuse switch, CB	LV feeder protection including a relay (U) and a CB	LV feeder protection including a relay (U) and a CB
	Operation	Manual	Manual or remote control	Adaptive protection settings,remote controlled, local measurements	Adaptive protection settings, remote controlled, local measurements
	Main operation functions	Overcurrent protection	Overcurrent protection	Directional overcurrent protection, isolation	Directional OC protection, isolation
	Communications	No communication	Possible to RTU at CSS	MMS, DG units	MMS, DG units
PD3C	Device type	Switch fuse	Switch fuse	CB	CB
	Operation	Manual	Manual	Manual	Manual, Local measurements
	Main operation functions	Overcurrent protection	Overcurrent protection	Service cable protection	Service cable protection
	Communications	No communication	No communication	No communication	PD2
PD3F	Device type	Plug fuse	Plug fuse	Plug fuse	Plug fuse
	Operation	Manual	Manual	Manual	Manual
	Main operation functions	short circuit & overcurrent protection of the customer installation	short circuit & overcurrent protection of the customer installation	short circuit & overcurrent protection of the customer installation	short circuit & overcurrent protection of the customer installation
	Communications	No communication	No communication	No communication	No communication
PD4	Device type	LOM protection relays, isolation, MCB	LOM protection relays, isolation, MCB	MCB, MCCB	MCB, MCCB
	Operation	Manual or remote control locally	Manual or remote control	Manual or remote control	Manual or remote control
	Main operation functions	LOM protection, DG unit protection	LOM protection, DG unit protection	DG unit protection	DG unit protection,
	Communications	Local remote control system, AMR	Local remote control system, AMR	PD2, MMS	PD2, MMS
PD5	Device type	Switch-disconnector, switch fuse or fuse switch	Switch-disconnector, switch fuse or fuse switch	Switch-disconnector, switch fuse or fuse switch	Swith-disconnector, fuse switch disconnector, CB
	Operation	Manual	Manual	Manual	Remote controlled
	Main operation functions	Connection/disconnection	Connection/disconnection	Connection/disconnection	Connection/disconnection
	Communications	No communication	No communication	No communication	PD2

Table 11. Main characteristics of equipment in LV distribution networks under evolution phases.

Node		Traditional	Boom of Microgeneration	Microgrid	Intelligent Microgrid
Energy meter	Device type	One-way or two-way energy meter	Two-way energy meter	Two-way smart energy meter	Interactive customer gateway
	Operation	Local measurements, Remote read	Local measurements, Remote read, Remote control, Alarms	Local measurements, Remote read, Remote control, Alarms	Local measurements, Remote read, Remote control, Alarms
	Main operation functions	Measurments of energy, power, voltage, current	Measurements of energy, power, voltage, current Outage information Measurements of quality of electricity Remote control of loads	Energy management, Outage management	Optimization of power flow with references of DGs, controllable loads, energy storages and actors
	Communications	DSOs' systems: AMR concentrator, meter reading system system	DSOs' systems, DG, loads	MMS, DSOs' systems, DG, EV, loads, ES, HAN	MMS, DSOs' systems, DG, EV, loads, ES, HAN, actors' control systems,
DG	Device type	Class 1, 2 and 3a	Class 1, 2, 3a, 3b, 4	Class 1, 2, 3a, 3b, 4	Class 1, 2, 3a, 3b, 4
	Operation	PV, wind, SG controlled locally	PV, wind, CHP controlled locally	PV, wind, CHP controlled locally and remotely	PV, wind, CHP controlled locally and remotely
	Main operation functions	Supplementary and reserve source of energy	Compensatory source of energy, Local control of voltage	Overriding source of energy, Participating to the centralized control of voltage	Overriding source of energy, Participating to the centralized control of voltage control, Participating to the frequency control
	Communications	Class 1 and 2: No communication Class 3a: Energy meter, disconnector	Class 1 and 2: No communication Class 3a, 3b and 4: Energy meter, disconnector	Class 1and 2: No communication Class 3a, 3b and 4: Energy meter, disconnector and MMS	Class 1and 2: No communication Class 3a, 3b and 4: Energy meter, disconnector and MMS
EV	Device type	Passive load	Active load (+ passive)	V2G (+ active and passive	V2H (+ V2G, active and
	Operation	Manual	Remote control, local measurements	Remote control, local measurements	Remote control, local measurements
	Main operation functions	Charging the battery	Charging the battery The use as a controllable load	Charging the battery The use as a controllable load Energy supply to the grid	Charging the battery The use as a controllable load Energy supply to the grid Energy supply to a small islanded grid
	Communications	No communication	Energy meter, local control system	Two-way energy meter, local control system	Two-way energy meter, local control system, disconnector, consumer loads
Controllable loads	Device type	Passive load (heating)		Load classes or priorities	Load classes or priorities
	Operation	Remote control	Remote control	Remote control	Remote control
	Main operation functions	Active power reduction	Active power reduction	Active power reduction, DSM, Blackstart	Active power reduction, DSM, Blackstart
	Communications	Energy meter	Energy meter	Two-way Smart energy meter	Interactive customer gateway, MMS

5 INTERGRATING TO DISTRIBUTION AUTOMATION

The introduced evolution phases of the LV distribution networks towards intelligent microgrids have their specific elements (studied in the chapter 3) in a certain phase of intelligence. In addition the increasing number of DERs in the LV distribution networks calls for a certain management system or a MMS. The subsystems connected to the control system in higher level or integration to the NCS is studied in this chapter. Feasible management architecture for microgrids to be connected with the NCS in general is presented. Thereafter requirements for data transmission or communications are reviewed in the aspect of the number of addressing nodes, capacity for transferred data types and event frequencies. Based on the results of the quantitative requirements the presented management architecture is applied on LV microgrids in the urban, suburban and rural areas.

5.1 Microgrid management architecture

Schwaegerl et al. (2009) propose a microgrid control and management architecture, which composes of three different control levels. The levels are local micro-source controllers (MCs) and load controllers (LCs), microgrid central controller (MGCC) as well as central autonomous management controller (CAMC). MCs follow the commands from MGCC and control the voltage and the frequency based on local information. Local LCs follows the orders from the MGCC and they provide capabilities for the load management. The MGCC optimizes the local production capabilities by sending control signals to MCs and LCs. The information exchange in such microgrid could be every 15 min for MGCC to produce the functions for an aggregator or an energy service provider, who acts in the interest of one or more microgrids. The microgrid operation is optimized by the MCCG according to market prices, the micro-sources and the forecasted loads. The control and management architecture described is presented in the Figure 41.

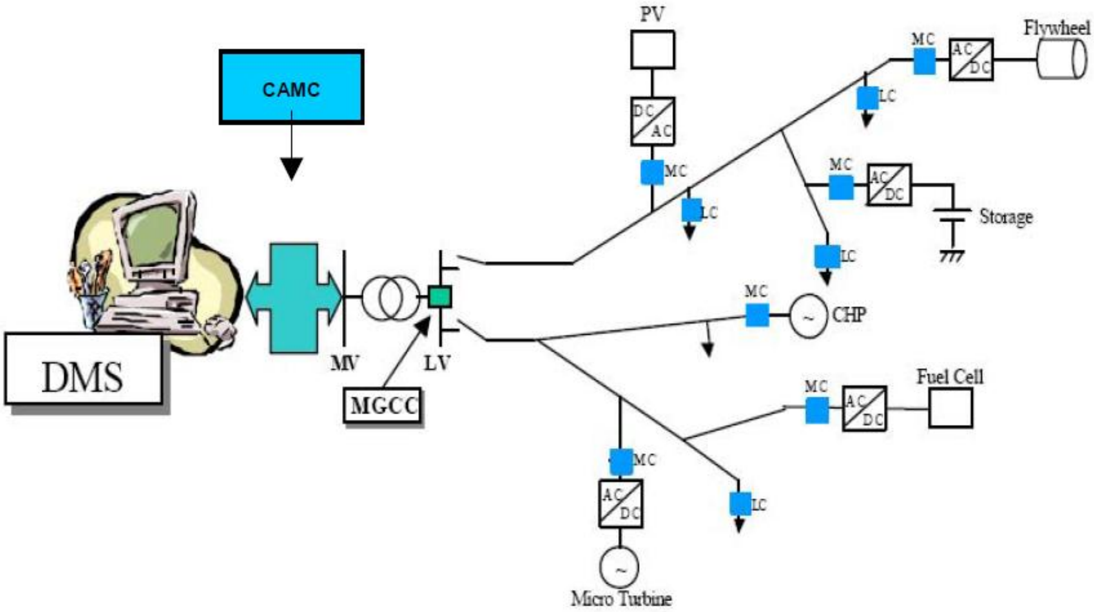

Figure 41. Control and management architecture for a microgrid (Schwaegerl et al. 2009: 20).

The Figure 42 presents a control and management structure for multi-microgrid (MMG), which introduces an extension for the afore-described concept. MMG is formed at a MV level and it consists of several LV microgrids, which are connected to the adjacent MV feeders. A CAMC is installed at the HV/MV substation and it is an interface to the DMS. The CAMC can be seen as one new application of the DMS. An adequate control and management strategy would still be based a hierarchical structure, because the CAMC collects data from multiple agents and establish the rules for lower agents. A purely central management system would not be effective because the large amount of data to be handled as well as central management only would not ensure an autonomous management during island mode of microgrid operation. Therefore is reasonable that the CAMC communicates with local controllers like MGCC, MS or loads connected to the network. (Schwaegerl et al. 2009).

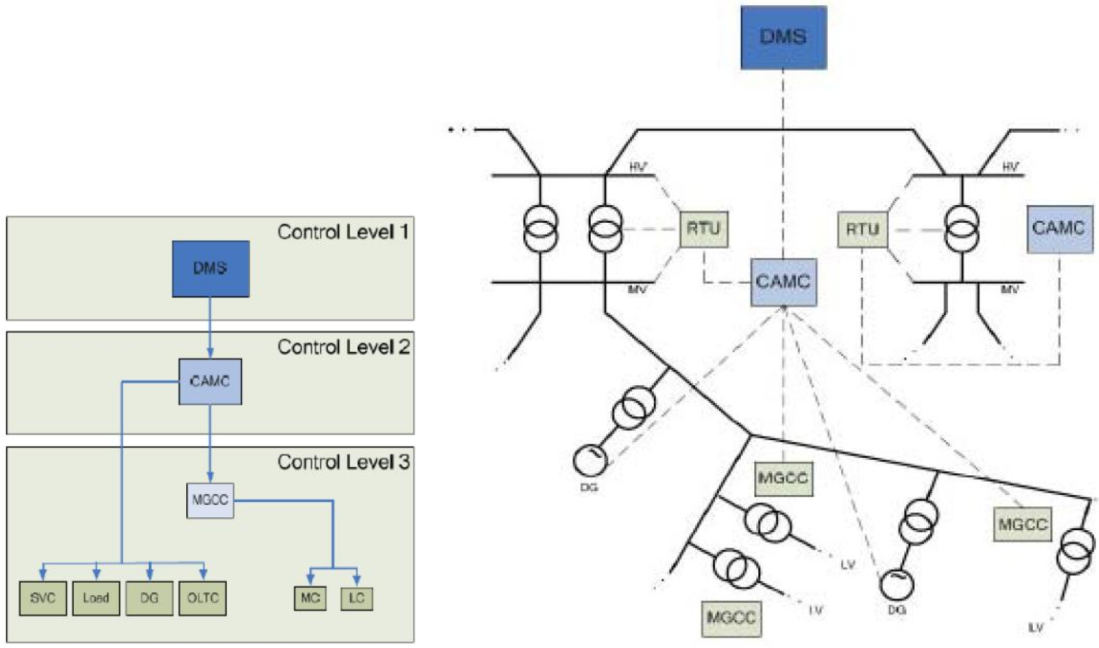

Figure 42. Hierarchical control and management architecture for a multi-microgrid (Schwaegerl et al. 2009: 24).

The main functions of a CAMC can be (Schwaegerl et al. 2009):

- local data acquisition
- dialogue with the DMS
- running specific network functionalities
- scheduling different agents in the downstream network agents
- receiving the information from the DMS
- measurements from the RTUs located at the MV network and existing MGCC

For implementing the concept to the defined evolution phases 3 and 4, there can be formed four control levels as follows:

- Level 3: *Area control level*, like CAMC or central microgrid management system (CMMS)
- Level 2: *Automatic control system level*, like MGCC or MMS
- Level 1: *Protection level*

- Level 0: *Process or device level* like monitoring and metering

A scheme of the communication architecture for secondary substations and customer automation systems to be connected to the NCS is presented in the Figure 43, where the four control levels are illustrated. In the secondary substation a monitoring and metering (M&M) unit, a RTU unit, a gateway (GW), a MMS or a gateway or a central gateway (CGW) are interlinked with the NCS in the level 3. In the level 2 operates MMS or a home automation system (HAS), in the level 1 feeder protection acts. In the level 0 different sensors and actuators act.

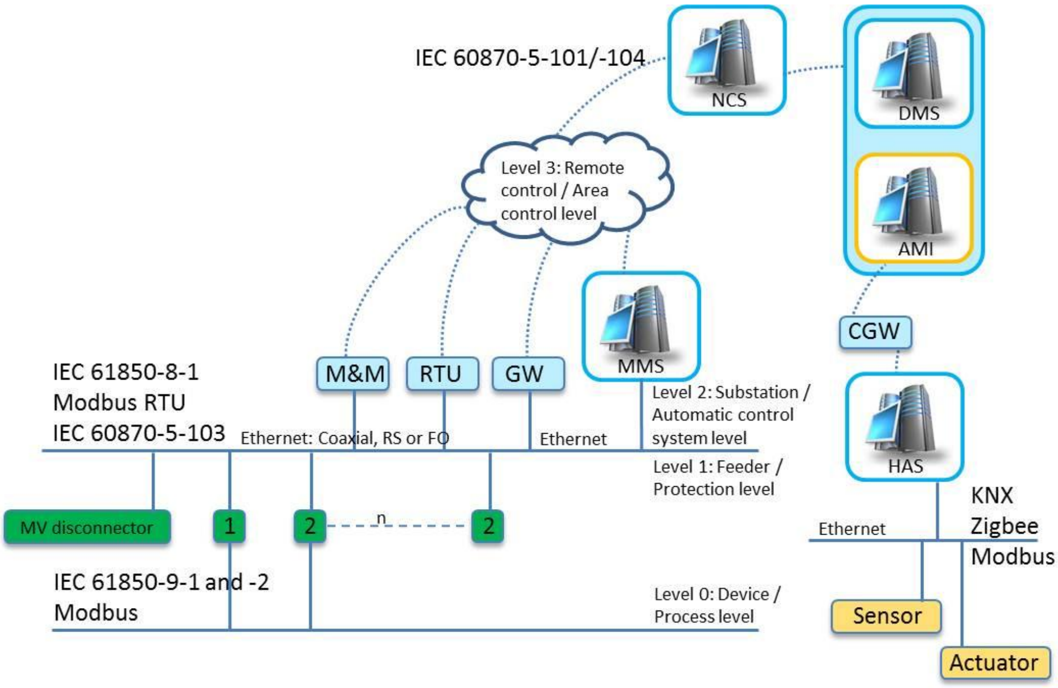

Figure 43. Control and management architecture for secondary substations and home automation to be connected to the NCS.

5.2 Requirements for communication

Based on the summary in the Chapter 4.5, the requirements for data transmission in the LV distribution networks are examined. The focus of examination is on the number of physical devices, the capacity requirements for transferred data types and the number of events for producing the quantitative requirements for data transmission in urban, suburban and rural areas.

5.2.1 Nodes

The numbers of physical nodes are evaluated based on data of Vattenfall's distribution network in Finland. The Table 12 presents the numbers of primary and secondary substations, MV and LV feeders amongst others. The numbers are not exact and the margin of error is assumed to be larger for urban and suburban areas compared to rural area, because urban areas compass smaller areas having higher power density.

Table 12. Numbers of different elements in an electricity distribution network. (Adapted from Muszynski 2011: 10).

	Urban	Suburban	Rural
HV/MV substation area km^2	7	57	460
HV/MV substations	13	20	104
Customer sites per a HV/MV substation	4002	4208	2471
MV feeders per a HV/MV substation	8,0	6,5	6,0
MV feeders	104	130	624
MV/LV substations per a MV feeder	6,1	13,5	30,5
Customer sites per MV feeder	500	647	412
MV/LV substations per km^2	6,7	1,5	0,4
LV feeders per a MV/LV substation	4,0	3,5	3,0
Customer sites per a LV feeder	20,5	13,7	4,5
LV feeders	2537,6	6142,5	57096,0
Customer sites per MV/LV substation	82	48	14
Customer site density	553	73	5
Customer sites within area	52021	84152	256932

The numbers of the Table 12 can be divided downward to the consumer-end and combine them to the control and management architecture of a multi-microgrid for the inspected LV microgrids in the phases 3 and 4. The Figure 44 presents a structure of a multi-microgrid control and management system with numbers of the prime physical nodes or MMSs. The number of prime physical nodes or MMSs to be connected with the NCS depends highly on whether the communication is straight to the NCS or via CMMS. In suburban area 20 primary substations are connected to the NCS, substations include 7 MV feeders each and further a MV feeder includes 15 secondary substations or MMSs, so the maximum number of MMSs communicating directly to the NCS is 2100 as for the number is 140 via CMMSs.

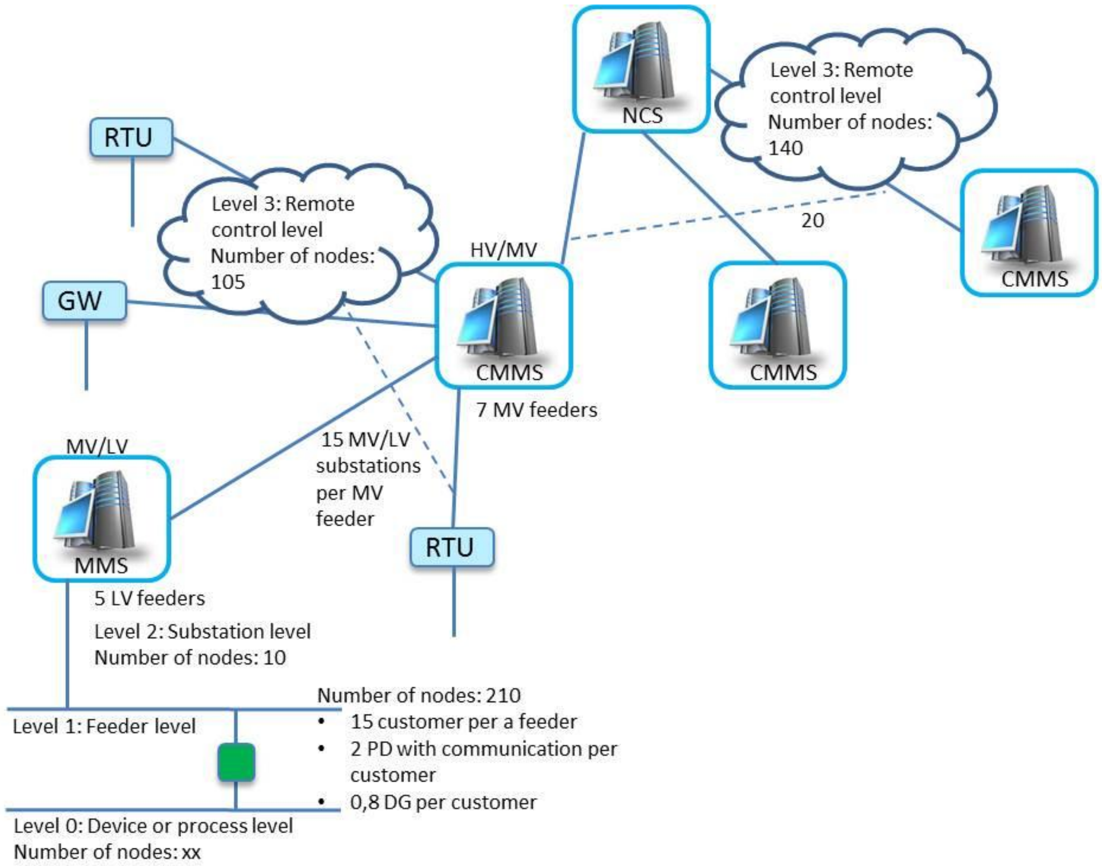

Figure 44. The number of physical nodes in hierarchical multi-microgrid control and management architecture.

5.2.2 Capacity requirements for transferred data types

The introduced control and management system requires different types of data transmission to be adopted for measurement data, protection functions, control commands and alarm signals amongst others. The data transmitted can be utilized for metering, protection and control as well as energy management as the Figure 45 presents, which is one vision of Smart Grid communications. The figure describes well how, for example, measurement data are gathered from different nodes to several systems like SCADA, DMS and billing as well as how the systems are interlinked together to share the data.

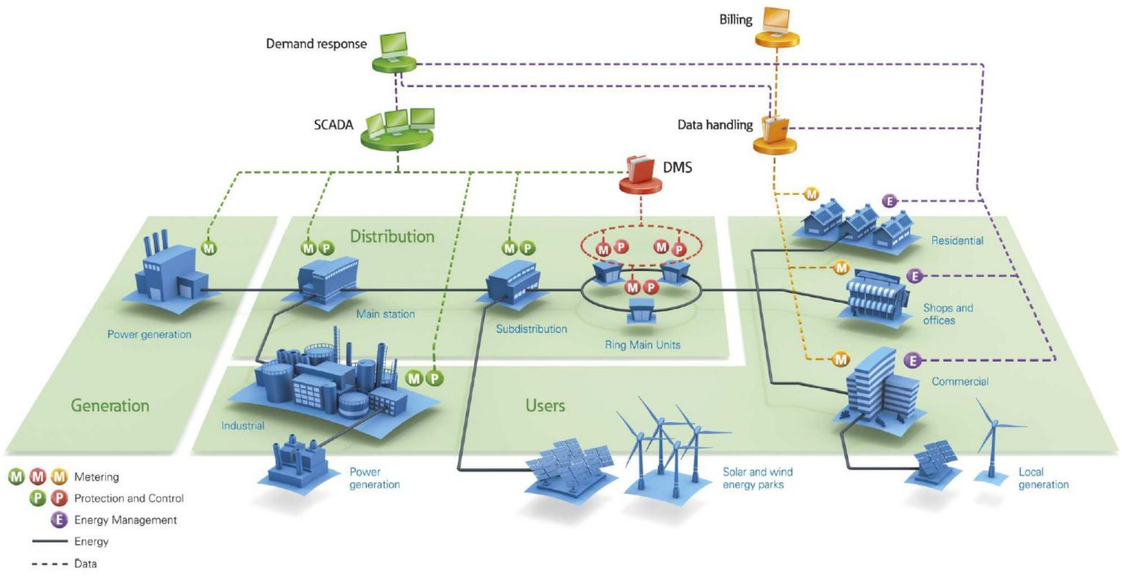

Figure 45. Eaton Smart Grids view (Mahamud 2011).

The capacity requirements for transferred data types can be divided roughly to measurement data (for monitoring or respective purposes), alarms and controls. In this chapter the focus is on measurement data and alarms. Capacity requirements for transferring the most general measurement data is presented in the Table 13. In addition to effective data, extra data is needed for different identifications, connecting, disconnecting and noticing. Therefore the estimated amount of total data is about 1.5 times of the effective data, so for example, the total data amount for average hourly power is 156 bit.

Table 13. Capacity requirements for transferring measurement data (Valtonen 2009: 50).

Measurement data	Required effective capacity [bit]
Average hourly power (P, Q, I, time stamp, customer id)	104
Quality of electricity (P, Q, U, I, time stamp, customer id)	120
Voltage and current (U, I, time stamp, customer id)	88
Supply interruptions (time stamp x2, P,Q, I, customer id)	144

The total amount of measurement data to perform a certain remote controlled function can be derived from on the effective capacity of measurement data. The Table 14 presents the requirements for data transmission for remote reading of different measurement values, which were defined in INCA research programme. The amount of measured data to be transmitted for different functions is presented in the table 14. For example transferring average hourly power requires effective capacity 104 · 24 kbit and in addition the tariff data should be added. As the measured data is designed to be utilized in more time-critical functions, the required effective capacity multiplies as shown in the Table 14.

Table 14. Requirements for data transmission as for remote reading of different measurement values. (Valtonen 2009: 52).

Function	Cycle	Data to be tranmitted	Required effective capacity [kbit]	Total capacity [kbit]
Supply interruption	evently	time stamp x 2, P,Q, I, customer id	0,150	0,225
Average power per day by hourly intervals	per day	Average hourly power in 24 h time: time stamp, P, Q, U, I, customer id	2,500	3,750
Average power per day by second intervals	on demand	Average minute power in 24 h time: time stamp, P, Q, U, I, customer id	150	225
Average power per day by minute intervals	on demand	Average hourly power in 1 h time: time stamp, P, Q, U, I, customer id	375	562

At present measurements of average power for billing purposes at hourly intervals are required to perform at least once in a day, so the total time for transmission is 24 h. In future the requirements for this transmission time will be shorter depending on utilization of the requested data like functions for asset management. Available time to read the measured data into AMR management system depends on the bandwidth of communications and in the other hand of laws, regulations, service requirements (data availability and real time requirements) as well as the size of register in energy meters applied. (Valtonen 2009: 52).

5.2.3 Fault frequencies

By investigating fault frequencies in a distribution network, the frequency of alarm data is evaluated in normal failures and in exceptional circumstances like in storms. Fault frequency in Vattenfall's MV distribution network in Finland is presented in the Table 15. The numbers of average fault frequencies are in year 2010 and hourly peak fault frequencies during Sylvi-thunderstorm within the whole distribution network area as well as within the affected area. In year 2010 Sylvi thunderstorm caused lack of energy supply for 60 000 customers (Muszynski 2011: 18-19). The table shows that *the fault frequency per hour in the MV distribution network increased over 1000 times under the thunderstorm* (peak to average event rate i.e. PAER -time and -area) in the affected area, which means in fault numbers about 10 faults per hour in suburban and almost 400 in rural area.

Table 15. Average fault frequencies and fault frequencies during Sylvi thunderstorm in year 2010 in Vattenfall's distribution network (Muszynski 2011: 18–19).

Average fault frequency 2010				
MV faults	Urban	Suburban	Rural	Total
per 100km/a	6,3	7	15,5	
per a	26,2	81,9	3191,8	3299,9
per h	0,003	0,009	0,364	0,377
Hourly peak fault frequency during Sylvi thunderstorm				
MV faults	Urban	Suburban	Rural	Total
peak to average event rate (PAER-time)	431	431	431	
peak MV faults / h	1,29	4,03	157,04	162,36
Hourly peak fault frequency during Sylvi thunderstorm within affected area				
MV faults	Urban	Suburban	Rural	Total
peak to average event rate (PAER-area)	2,37	2,37	2,37	
peak to average event rate (PAER-time and -area)	1021,2	1021,2	1021,2	
peak MV faults / h	3,05	9,55	372,09	384,69

The Table 16 presents average fault frequencies and hourly peak fault frequencies during Sylvi thunderstorm in the whole Vattenfall's *LV distribution network* in year 2010 (Muszynski 2011: 19). Within the affected area the value of PAER -area is 2.4 *under Sylvi thunderstorm, so the amount of customer outage notice is calculated to be 10.6* ($4.4 \cdot 2.4$) *in urban, 33.4 in suburban and 1296 in rural area per an hour*. Secondly the numbers shows that the fault frequency per hour increased over 1600 times ($8760 \cdot \frac{1296}{7022}$) in rural area compared to average fault frequency under the thunderstorm within the affected area in the LV distribution network.

Table 16. Average fault frequencies and fault frequencies during Sylvi thunderstorm in year 2010 in Vattenfall's LV distribution network (Muszynski 2011: 19).

Average fault frequency 2010						
LV faults per a	% of MV faults	Urban	Suburban	Rural	Total	
Customer outage notice	220,0 %	57,6	180,2	7022,0	7260	
LV zero conductor fault	12,0 %	3,1	9,8	383,0	396	
LV one phase missing	125,0 %	32,8	102,4	3989,8	4125	
LV voltage level	5,0 %	1,3	4,1	159,6	165	
MV broken conductor	1,5 %	0,4	1,2	47,9	49	
MV remaining faults	98,5 %	25,8	80,7	3143,9	3250,40	
Hourly peak fault frequency within whole distribution network during Sylvi tunderstorm						
LV faults per a		Urban	Suburban	Rural	Total	PAER time
Customer outage notice		4,4	13,9	540,4	558,7	674,1
LV zero conductor fault		0,2	0,8	29,5	30,5	674,1
LV one phase missing		2,5	7,9	307,0	317,4	674,1
LV voltage level		0,0001	0,0005	0,0182	0,0188	1,0
MV broken conductor		0,0	0,1	2,4	2,4	430,9
MV remaining faults		1,3	4,0	154,6	159,9	430,9

Further, the intermittent faults cause fault current alarms and switching state indications. Generally, high speed automatic reclosing (HRS) events are carried out two times before delayed reclosing, and if delayed reclosing fails, permanent fault exists in the network and it has to be isolated. Considerable is that the protection system for microgrids, which were introduced in the chapter 4.3.3 requires for the MV feeder protection to send information signals to the MMS system of faults.

The Table 17 presents the triggered events in Vattenfall's distribution network assuming that one recloser is located along a MV feeder. In suburban area were 82 faults in year 2010 producing over 1600 events as well as HSRs produced were over 500 and delayed reclosings produced 300 alarms, so for example, totally about 2500 alarm events appeared in suburban area. In the rural area the number is 102700 and in urban area 720. Based on these numbers, *events caused by intermittent faults per hour were 0.082 in urban, 0.240 in suburban and 11.724 in rural area in the MV network.*

Under the Sylvi-thunderstorm, based on the PAER-time 647.1 and the PAER -area 2.4 of faults in LV distribution network, *the maximum number of different alarm signals per hour can be calculated to be about 130* ($0.082 \cdot 647.1 \cdot 2.4$) *in urban, 380 in suburban and 18 200 000 in rural area in the affected MV network.* These numbers divided to numbers of MV feeders according to the Table 12, gives the maximum number of signals, which the PD1 has to receive from the MV feeder protection. In urban area the number is 1.25, in suburban 2.92 and in rural 29167. The numbers shows, that data amount of alarm events from MV feeder protection (in fault F1 situation) for PD1 to be received is significant only in rural area, that is approximately 8 signals per a second (the worst case).

Table 17. Triggered events in Vattenfall's LV distribution network (Muszynski 2011: 20).

Reclosing and fault isolation Statistics 2010	Urban	Suburban	Rural	Total	Remarks
successful HSR	13 %	43 %	53 %		Of all fault interruptions
successful DR	14 %	18 %	23 %		Of all fault interruptions
permanent faults	73 %	39 %	24 %		Of all fault interruptions
Reclosing events	Urban	Suburban	Rural	Total	Remarks
HSR	35,0	175,2	8819,1	9029	3 alarms (OC+open+close)
along feeder (pole mounted)	0,0	40,4	1413,0	1453	
at HV/MV substation	35,0	134,8	7406,1	7576	
DR	30,5	99,8	4145,2	4276	3 alarms (OC+open+close)
along feeder (pole mounted)	0,0	23,0	664,3	687	
at HV/MV substation	30,5	76,8	3480,9	3588	
unsuccessful DR	26,2	81,9	3191,8	3300	2 alarms (OC+open)
along feeder (pole mounted)	0,0	18,9	511,5	530	
at HV/MV substation	26,2	63,0	2680,3	2770	
Permanent faults, isolation with disconnec	26,2	81,9	3191,8	3300	5 retries, total 20 events

The other way round is alarm signals from customers in LV distribution network, which are envisaged to be sent from smart energy meters. Based on the data of the Table 12 and the Table 15, the average fault frequency under a thunderstorm in the LV network is presented in the Table 18, assuming the smart energy meters will notice the lack of supply. This means for example in suburban area over 6000 alarms per hour when alarms goes straight to a meter reading system, and 130 alarms per hour only if the signals are concentrated in a MV/LV substation area.

Table 18. Maximum number of outage signals from smart energy meters under a thunderstorm in LV distribution network

	Urban	Suburban	Rural
MV network peak faults/h under Sylvi	3,05	9,55	372,09
Customer sites per MV feeder	500	647	412
Customer outage alarms / h	1526	6182	153208
Customer sites per MV/LV substation	82	48	14
Customer outage alarms / h	19	129	11349

Energy meter reading events as well as fault signals from energy meters in the Vattenfall’s distribution networks are presented in the Appendix 3, which shows clearly that energy reading remotely has the major part of the data transmission events concerning the present LV distribution networks.

5.2.4 Quantitative requirements

Based on the presented statistics it can be concluded that there are different requirements for communication depending of the functions to be exploited like metering, protection and control or energy management. Tables 19 – 21 present some quantitative requirements for communication in urban, suburban and rural areas, which are based on the amount of measurement data transfer, fault frequencies, microgrid concept and multi-microgrid concept. Other requirements like data integrity for monitoring or control are not studied. In the table above-mentioned subjects are connected to DA functions. The numbers are only rough approximates in a DSO’s distribution network, but shows clearly the benefits of multi-microgrid concept.

Table 19. Quantitative requirements for communication in urban area of LV distribution network.

Business functions in a DSO	**Number of addessing nodes via CMMS [pcs]**	**Number of addessing nodes via MMS [pcs]**	**Amount of data transfer / day via CMMS [Mbits]**	**Amount of data transfer / day via MMS [Mbits]**	**Interval via CMMS [s]**	**Interval via MMS [s]**
	urban	urban	urban	urban	urban	urban
Remote control of secondary substation (e.g MMS) & Microgrid interconnection device	13	624	?	?	?	?
Signals to PD1/Microgrid interconnection device from FA of MV max.			4	55	4 566	351
Signals to PD1/Microgrid interconnection device from FA of MV avg.	13	624	0,0043	0,0554	4 565 854	**351 220**
Secondary substation automation	N/A	285	N/A	N/A	N/A	N/A
FA in secondary substation	N/A	235	N/A	N/A	N/A	N/A
Meter reading	4 032	52 416	15	197	3 600	3 600
Outage alarms per hour from customer max.	0,0	**0,4**	0,907	12	112 320	8 640
Outage alarms per hour from customer avg.	0,00002	0,00026			2,E+08	1,E+07
Straight to AMR system						
outage alarms / hour	**20,0**					180

Table 20. Quantitative requirements for communication in suburban area of LV distribution network.

Business functions in a DSO	Number of addessing nodes via CMMS [pcs]	Number of addessing nodes via MMS [pcs]	Amount of data transfer / day via CMMS [Mbits]	Amount of data transfer / day via MMS [Mbits]	Interval via CMMS [s]	Interval via MMS [s]
	s urban	s urban	s urban	s urban	s urban	s urban
Remote control of secondary substation (e.g MMS) & Microgrid interconnection device	20	1 960	?	?	?	?
Signals to PD1/Microgrid interconnection device from FA of MV max.			9	185	2 100	105
Signals to PD1/Microgrid interconnection device from FA of MV avg.	20	1 960	0,0093	0,1851	2 100 000	**105 000**
Secondary substation automation	N/A	89	N/A	N/A	N/A	N/A
FA in secondary substation	N/A	39	N/A	N/A	N/A	N/A
Meter reading	1 372	27 440	5	103	3 600	3 600
Outage alarms per hour from customer max.	0,0	**0,7**	0,309	6	110 250	5 513
Outage alarms per hour from customer avg.	0,00002	0,00041			2,E+08	8 820 000
Straight to AMR system						
outage alarms / hour	**64**					56

Table 21. Quantitative requirements for communication in rural area of LV distribution network.

Business functions in a DSO	Number of addessing nodes via CMMS [pcs]	Number of addessing nodes via MMS [pcs]	Amount of data transfer / day via CMMS [Mbits]	Amount of data transfer / day via MMS [Mbits]	Interval via CMMS [s]	Interval via MMS [s]
	rural	rural	rural	rural	rural	rural
Remote control of secondary substation (e.g MMS) & Microgrid interconnection device	104	19 344	?	?	?	?
Signals to PD1/Microgrid interconnection device from FA of MV max.			101 458	10 551 600	0,192	0,002
Signals to PD1/Microgrid interconnection device from FA of MV avg.	104	19 344	101	10 552	192	**1,842**
Secondary substation automation	N/A	92	N/A	N/A	N/A	N/A
FA in secondary substation	N/A	42	N/A	N/A	N/A	N/A
Meter reading	2 790	290 160	10	1 088	3 600	3 600
Outage alarms per hour from customer max.	0,1	**13,3**	0,628	65	28 069	270
Outage alarms per hour from customer avg.	0,00008	0,00834			4,E+07	431 826
Straight to AMR system						
outage alarms / hour	**2481**					1,451

5.3 Communication interfaces

Feasible communication media and protocols for different evolution steps of the LV distribution networks should be considered carefully. Media and protocols have to fulfil many requirements to realize different functions for different applications of the DA.

Some of the requirements for the data transfer were introduced in the previous chapters. Interfacing nodes of the LV distribution network with DA systems system are presented in the Figure 46. DA systems include NCS or SCADA, DMS, AMR or AMI system, MMS or a LV distribution management system. Remote control of secondary substations can be either straight between the MMS and the NCS or via the CMMS. The CMMS can be located in the primary substation or in other place feasible place. Automation system for secondary substations like the MMS controls the connected devices and sub-systems. LV feeder automation should be implemented by rational and cost effective way.

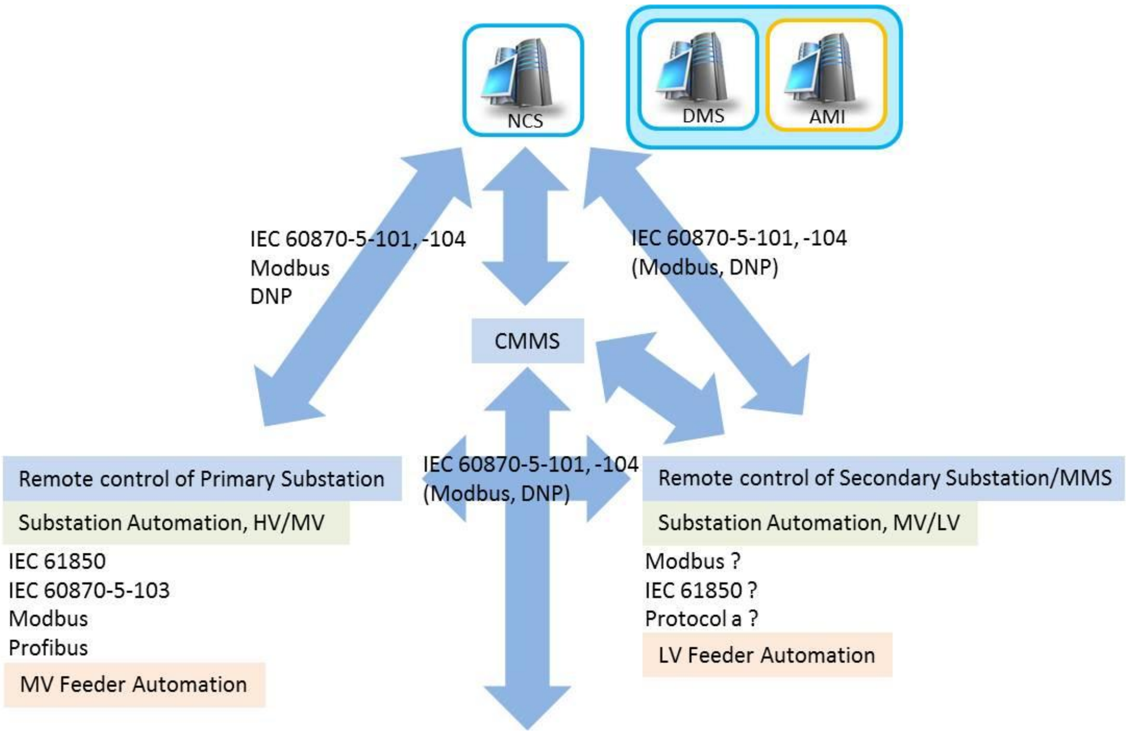

Figure 46. LV distribution automation system.

In addition communication media and protocols between different nodes for different evolution phases should be considered by applications of DA. The application use the functions produced by a device or a system in a LV distribution network. In addition overlapping functions produced by different devices should be considered. The Figure 47 presents the main devices and systems which can produce functions to be exploited in DA applications like outage management or load flow calculation. The functions of applicable protocols should be examined in details to evaluate the most suitable device or system as well as protocol. On the other hand, redundancy of functions could be beneficial also for securing data transmission. In the first place it would be reasonable to map the required and desired functions for different DA applications, and thereafter the long distance communication protocols and local automation protocols.

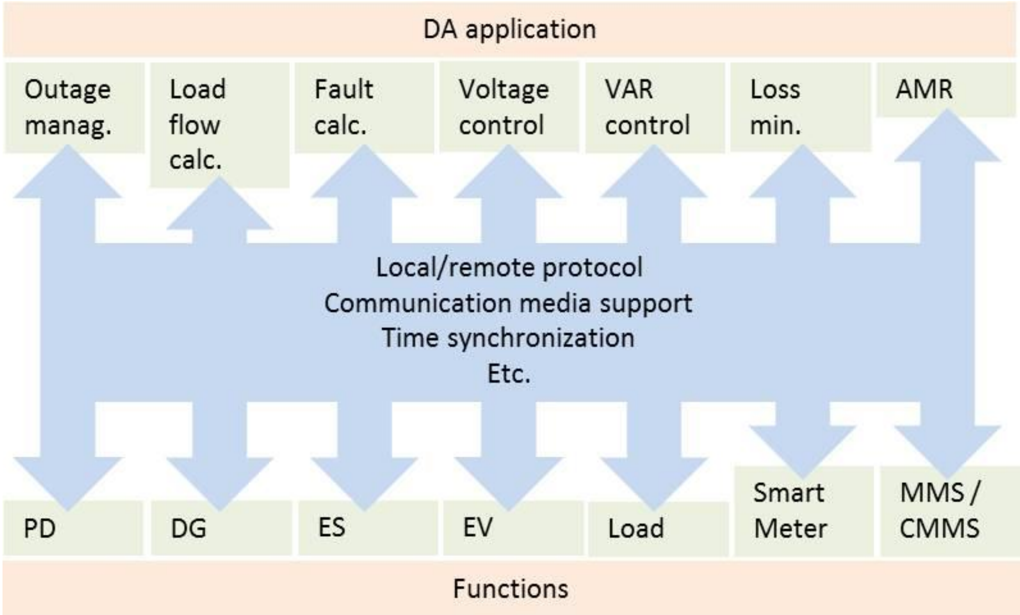

Figure 47. Protocols linking functionalities.

6 CONCLUSIONS

Evolution of LV distribution networks towards intelligent microgrids can be divided into four phases, which are called in this thesis as traditional, boom of DG, microgrid and intelligent microgrid. The major differences between the phases are the amount of the DG units connected to the national grid, the level of local intelligence and remote controllability.

In traditional phase few users exploit micro generation for own energy consumption only. DG units operating parallel with the national network have to fulfill the requirements of LOM protection for preventing the island operation, as stated in grid codes of DSO's applicable. DG units operate based on local set-parameters. The amount of smart energy meters is increasing enabling simple controllability of passive loads like heating.

Boom of DG takes place when the amount of micro and small-scale generation is notable compared to the local and regional consumption in the area of the LV distribution network. Regional energy production, like CHP units, is built up aiming for self-sufficiency in energy. The increased amount of grid-connected DG brings along challenges for the protection of the network as well as for the control of voltage level. The validity of the short circuit protection has to be checked by DSOs in relation to sensitivity and selectivity amongst others. In addition the rise of steady-state voltage, voltage dips and fluctuations have to be considered. Managing these challenges will put pressure on actors to utilize a control system shortly.

Microgrids responds to these challenges by a local control system called MMS, which controls protective devices and DG units in normal and in island operation mode of the formed LV microgrid. The capability of the microgrid to operate in island mode forces to replace passive protection devices to adaptive ones, for example traditional fuses to CB and IED with advanced functions. In addition, the MMS is connected to the NCS or SCADA for exploiting the functions of the DA such as load flow calculation or outage management down to the consumer-end.

Intelligent microgrids are mature for ancillary services by utilizing fully-developed availability of communications between different actors, systems and equipment. Every basic element of LV distribution networks and equipment connected into it, are advanced. DG units can be controlled based on different operation modes as well on interests of actors. DR is well established by categorizing different load types, which are controlled based on certain status of the LV network. EVs are capable for supplying energy to a small microgrid like small buildings. Smart energy meters are more intelligent serving as a customer gateway.

Introducing a communication system of LV distribution networks for a small commercial or residential area to be connected to DA is a complex issue. At present, low level of local automation in secondary substations, CDCs and buildings challenges the implementation of microgrids to existing networks. Nevertheless, new networks, which are under construction, should be built in to fulfil the future requirements.

The most significant issue is to adopt more intelligent protection system, in which the operation is based on communications and adaptive protection settings. A fast communication system between protective devices like CBs as well as MMS is needed for securing selective protection system in normal and island mode of grid operation. The most promising would be IEC 61850 protocol operating with GOOSE messages, which are capable for sending messages under 4 ms. In addition wireless media would be the most reasonable way to connect the devices, because the great number of connecting points as well as the changes of LV network topology. Therefore taking into account these aspects, a protection system should be based on wireless IEC 68150 communications. On the other hand development of MCCBs should come up with a communication module for IEC 61850 for answering the needs. At the moment MCCBs are well available with Modbus communication applying RS cable as the transmission path. The cost of currently available MCCBs is high for distribution applications. Therefore some technical requirements of MCCBs, which are mostly for industrial applications, should be reduced, like operational voltage or short circuit making or breaking capacity, to come up with feasible prices.

The central operational device of managing the LV distribution networks is the microgrid interconnection device, which can be a protection device including a CB with a voltage relay or it can be a fast static semiconductor switch. At present air circuit breakers (ACBs) are mature for managing these operational requirements. Data transmission is required to be between the NSC, microgrid interconnection device, MMS and FA from MV distribution (from protective relay of the feeder). Protocol for the bay level in the secondary substation should be IEC 61850 using fibre optics. At present some ACB is capable for IEC 61850, but mainly they are using Modbus or similar.

The maximum number of MMS within the area of a primary substation varies from 50 to 100 meaning totally 600 – 20000 systems in a DSO’s distribution network area. Therefore MMSs would be reasonable to connect with NCS via a centralized management system called CMMS. CMMSs could be located at primary substations or similar leading to reduced numbers of systems (10 – 100) to be connected with the NCS. MMSs or CMMSs are connected to NCS or SCADA within a long distance communications link utilizing wireless communication. Suitable protocols to be used depend on the existing system where to be implemented, which mostly use IEC 60870-5-101 and -104 at present.

Energy metering and management requires also a communication system which would not be as time-critical as the protection system. Therefore smart energy meters should be developed towards so called intelligent customer gateways, which are using the public communication systems. Adequate public wireless networks are 2G and 3G in addition to 4G or LTE, which is developing. Energy meters communicating by DLC and RS are not suitable to use in microgrids.

LV distribution networks, which participate in voltage control, require a fast communication system. Communications for the advanced protection system for microgrids is suitable to be used for voltage control including the protective devices, DG units and MMS.

The integration of LV distribution automation (LVDA) to the traditional DA system is a complex issue, where distributed as well as centralized systems are applying different communication networks or so called hybrid networks. Therefore a universal solution cannot be presented, but as the LV network tends to develop towards the intelligent microgrid, distributed communications within the microgrid area are needed as well as a central control system, which is interlinked to the upper DA system. AMI is a large parallel hybrid system and developing rapidly. Smart energy meters are accessible to provide data for ancillary services, but in addition the MMS could offer data to different actors for achieving more enhanced services in real-time.Therefore the possible overlapping functions produced by MMS or AMI must be considered and so choices have to be made which system will produce the desired function for the DA application. Considerable is also the possibility of redundant functions.

Functionalities of above-mentioned protocols should be examined in more details for providing desired facilities. Protocols IEC 60870-5, IEC 61850 and at least Modbus, which are running in general wireless networks should be compared at first, and thereafter communications in home area networks (HANs) and energy metering should be studied.

HANs are mostly realized by wireless technology applying wireless local area network (WLAN) standards and devices. WLAN standard IEEE 820.11n promises the speed of the data transfer to be over 100 Mbits, which is the same as cabled Ethernet has. Some buildings have Ethernet network, where devices are connected by RJ-45 connectors and RS cable to the concentrator, in addition telephone lines can be used. The range of WLAN is approximately 50 – 100 m so at least in urban and suburban area all WLANs connected together would cover the area of desired microgrid. In addition a home gateway (HGW) or a home server would offer the connecting point between the home automation (including controllable loads and ventilation amongst others), the microgeneration, the smart energy meter and the water meter. So HGW provides connectivity between upstream and downstream resources, linking different home equipment, and this equipment to the external networks. By connecting HGWs together as well as to the MMS in a microgrid area of the LV distribution, would be sufficient to achieve local energy management easily in addition to ancillary services.

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APPENDICES

Appendix 1. Interface protection settings 1.

Parameter	Clearance time s	Maximum trip setting
Over voltage (stage 1)	1,5	U_n + 10 %
Over voltage (stage 2)	0,15	U_n + 15 %
Under voltage (stage 1)	5	U_n - 15 %
Under voltage (stage 2)	0,15	U_n - 50 %
Over frequency	0,2	51,0 Hz
Under frequency	0,5	48,0 Hz
LoM [a]	0,15	

[a] LoM protection shall use recognized techniques suitable for the distribution network protection.

REMARK Isolation of the micro-generator shall be achieved by the separation of mechanical contacts. This mechanical device shall be a lockable isolation switch.

(EN 50438).

Appendix 2. Interface protection settings 2.

Taulukko 2. Tuotantolaitteiston suojauslaitteiden asetteluarvot

Parametri	**Toiminta-aika**	**Asetteluarvo**
Ylijännite	0,2 s	U_n + 10 %
Alijännite	0,2 s	U_n - 15 %
Ylitaajuus	0,2 s	51 Hz
Alitaajuus	0,2 s	48 Hz
Saarekekäyttö	enintään 5 s	

(Energiateollisuus 2011).

Appendix 3. Events in the Vattenfall's distribution network.

Events & event frequencies						
			Urban	Suburban	Rural	Total
	Use case	**Device**	**Events/a**	**Events/a**	**Events/a**	**Events/a**
AM reads	AMR	AM	18 987 592	30 715 571	93 780 180	143 483 343
Alarm zero conductor fault	AMR+DMS	AM	29	61	776	866
Zero conductor query	AMR+DMS	AM	29	61	776	866
Alarm one pase missing fault	AMR+DMS	AM	302	631	8 079	9 012
One pase missing query	AMR+DMS	AM	302	631	8 079	9 012
Alam voltage level	AMR+DMS	AM	66	265	6 571	6 902
Alam voltage unbalance	AMR+DMS	AM	88	358	8 871	9 317
AM query	AMR+DMS	AM	726	2 937	72 815	76 478
AM query	AMR+DMS	AM	957	1 999	25 595	28 551
IEC-104 event	FA	Recloser	0	556	20 023	20 579
IEC-104 command+reply	FA	Recloser	0	410	15 959	16 369
IEC-104 event	FA	Disconnector	0	0	0	0
IEC-104 command+reply	FA	Disconnector	288	901	35 109	36 298
Ping	FA	Recloser	0	15 768 000	52 560 000	68 328 000
Ping	FA	Recloser	0	1 576 800	5 256 000	6 832 800
Ping	FA	Disconnector	10 512 000	157 680 000	709 560 000	877 752 000
Ping	FA	Disconnector	1 051 200	15 768 000	70 956 000	87 775 200
IEC-104 MV, DI	FA	Recloser	0	22 075 200	73 584 000	95 659 200
IEC-104 MV, DI	FA	Disconnector	5 468 160	82 022 400	369 100 800	456 591 360
IEC-104 MV, DI	SS_CONN	GW_SS	22 075 200	66 225 600	765 273 600	853 574 400
IEC-104 Event	SS_CONN	GW_SS	354	1 088	50 788	52 230
IEC-104 Command+reply	SS_CONN	GW_SS	131	410	15 959	16 500
Ping	SS_CONN	GW_SS	1 576 800	4 730 400	54 662 400	60 969 600
Ping	SS_CONN	GW_SS	157 680	473 040	5 466 240	6 096 960
Total / a			59 831 904	397 045 319	2 200 468 620	2 657 345 843
Total / h			6 830	45 325	251 195	303 350
Total /s			19	126	698	843

(Muszynski 2011: 28).