D1.1 Scenarios and Requirements Specification

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DLC+VIT4IP team

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Executive Summary

This document holds typical use scenarios and the requirements specification for the Distribution Line Carrier implementation that will be built and tested during the DLC+VIT4IP project.

The scenarios are necessarily on a functional level. There is in the scenario definitions no clear lower level communication functionality defined, such as would be provided by the DLC equipment. The scenarios will be the basis for development of a series of tests that will be performed on the DLC+VIT4IP equipment that will be installed in the test beds.

The scenarios shall describe operations related to the overall energy saving and requirements resulting from the increased use of renewable energy. This is then, in turn, broken down to develop more implementation specific scenarios which are applicable to the scope of the project.

Additionally the technical and functional requirements are listed. This includes characterisation of requirements from the viewpoint of communication system, application dependent requirement definitions (AMM, DSM, SCADA and other), stability and security requirements, interoperability requirements, system management requirements, timing requirements including time base for the communication system and the applications, system latency, installation requirements, addressing and configuration requirements, outage management requirement, failure and alarm requirements.

The scenarios and requirements are a baseline. Additional scenarios may be added during the project as required.

1. System Use cases and Target Scenarios

There are many application use cases for which DLC-VIT4IP will clearly provide benefits. There are also many interpretations over which of these application use cases are the most important to study for many different reasons and motivations. It is the primary intention of this description to result in a focused subset of use cases and DLC Communication service scenarios, for which:

a) Are well known to be of importance to smart grid stakeholders.
b) Are known to provide benefit to the wider community in terms of energy saving and economic benefit
c) Justify the full range of capabilities that shall be enabled by DLC-VIT4IP

This description does not intend to provide detail interactions within scenarios but merely specifies which of those high level scenarios provide the most coverage of DLC-VIT4IP intended capabilities, application and stakeholder interests.

A broad range of application use cases is described. These are linked to specific categories of energy saving and economic benefit and link forward to a set of DLC Communication services which can be provided by DLC-VIT4IP.

These linkages are then filtered into 4 specific application scenarios which provide a wide coverage of the defined linkages and, hence the DLC capabilities which output from the DLC-VIT4IP project. For each application scenario, the associated DLC Communication Services are briefly described with a short form description of an Application Scenario; a typical communication interaction of the Application.

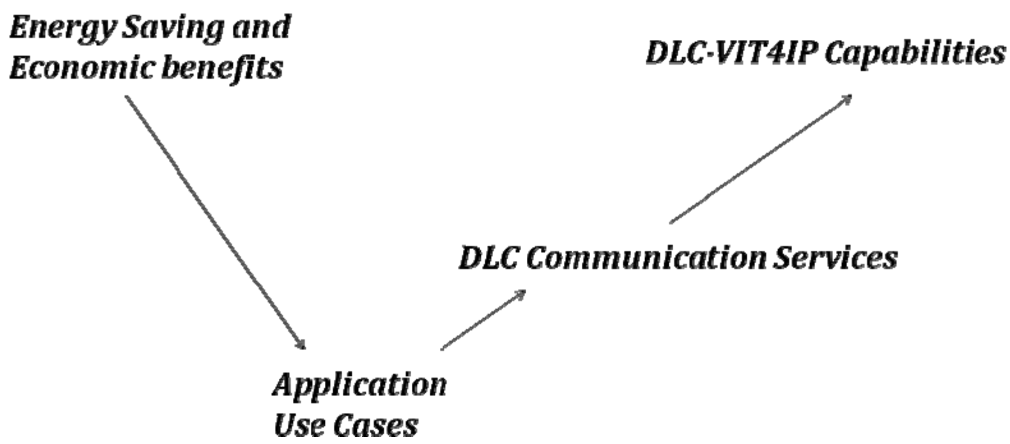


Figure 1 Approach to define Application Scenarios

1.1. DLC-VIT4IP System Model

This section draws from industrially accepted terms in order to put DLC-VIT4IP into the wider industry context. We also define some further terms which apply more specifically to DLC-VIT4IP :

Application	A source and/or sink of raw or source compressed data which may or may not be intended for DLC but can be transported by DLC.
DLC Communication Service	A service which provides IPv6 transport across the power network with specific set of *'DLC QoS'* options available (support of previous IP versions such as IPv4 currently used by most power utilities shall also be considered).
Operational Scenario	A scenario describing the relationship between *Energy Saving and Economic Benefits*, *Applications*, & *DLC Communication Services*
Elaborated DLC Communication Scenario	A more elaborate description of a *DLC Communication Service* but without specific signalling detail.

1.1.1. Use Case Actors, Domains and communicating objects in the Future Smart Grid context

In defining use cases it is important to understand who the key actors are.

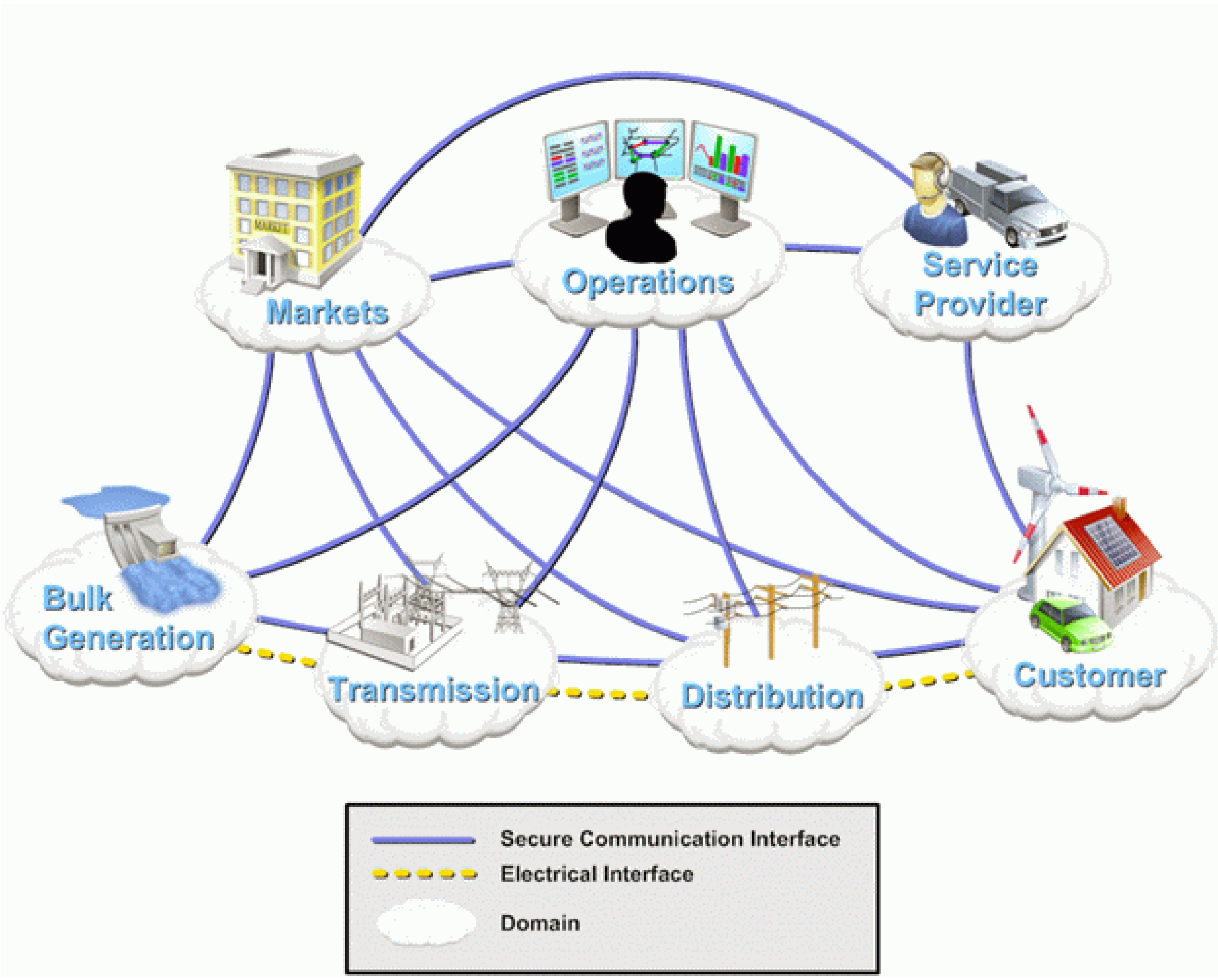


Figure 2 Conceptual Model derived from (NIST, 2010)

Figure 2 illustrates Smart Grid domains according to IEEE and NIST definitions (NIST, 2010). These include

- *Markets*

  The Markets Domain operates and coordinates the participants in electricity markets. It provides the market management, the wholesaling, the retailing and trading of energy services operation.

- *Operations*

  The Operations Domain manages and controls the electricity flow of all other domains. It uses a two-way communications network to connect to substations, customer premises networks and other intelligent field devices, providing monitoring, reporting, controlling and supervision status and important process information decision. Business intelligence processes gathers data from the customer and network and provides intelligence to support the decision making.

- *Service Providers*

  The Service Provider Domain handles all third party operations within the domains, such as the end customers energy efficiency management through energy web portals, data exchange for energy management between customer and the utilities, and the electricity supplied to homes and buildings. It may also manage other utilities processes such as demand response programs, outage management and field services.

- *Bulk Generation*

  The Bulk Generation Domain generates electricity from renewable and non renewable energy sources in bulk quantities. These sources can also be classified as renewable-variable sources, such as solar and wind; renewable non-variable such as hydro, biomass, geothermal and pump storage; or no renewable, non-variable, such as nuclear, coal and gas. It may also contain energy storage for later distribution.

- *Transmission*

  The **Transmission** Domain carries bulk electricity over power transmission lines over long distances, connecting the bulk generation to the energy consumption centres of the smart grid. It also contains the power system substations; the transmission and the distribution substations. It may also connect to energy storage facilities and alternative distributed energy resources at the transmission level.

- *Distribution*

  The **Distribution** Domain distributes the electricity to and from the end customers. The distribution network connects the smart meters and all intelligent field devices; manages and controls them through a two-way wireless or wire line communications network. It may also connect to energy storage facilities and alternative distributed energy resources at the distribution level.

- *Customer*

  The Customer Domain is where the end users (home, commercial/building, and industrial) of electricity are connected to the electric distribution network through the smart meters. The smart meters control and manage the flow of electricity to and from the customers and provide energy information about energy usage and patterns. Each customer has its own domain comprised of electricity premise and two-way communications networks. It may also generate, store, and manage the use of energy and the connectivity with plug-in-vehicles.

Both electrical interfaces and secure communications are presented, connecting the domains. Table 1 illustrates technologies that are appropriate for secure communication between these domains.

	Communication Channel		
	Glass fibre Broadband	Copper cable Broadband	DLC/PLC
Markets	*	*	
Operations	*	*	*
Service Providers	*	*	*
Generators (large scale)	*	*	
Transmission Grids	*	*	*
Distribution grids		*	*
Customers			*

Table 1: Communication Technologies appropriate for Domain Secure Communication

Information exchange is required between objects that are housed within these domains. Table 2 illustrates some of the key objects that require secure communication.

Party	Object
Markets	Market System
Operations	SCADA System
	Fault prediction and diagnostic systems
	Grid security systems
	Mobile worker
Service Providers	Billing and Settlement
	Connect / Disconnect functions
Generators (large scale)	Controller
Transmission Grids	Substation controllers, controlling • Switches, breakers • Transformers
Distribution grids	Substation controllers, controlling • Switches, breakers • Transformers • The other grid elements
Customers	Meters
	Small scale generation
	Distributed Energy Resources (DER)

Table 2 Objects involved in performing domain functions and communication

1.1.2. Energy Saving and Economic Benefits

Figure 3 illustrates the linkages that are identified between three key Energy Saving and Economic Benefits. Whilst the technical aspects connecting the domains as described above provide the means to providing overall economic, technical and social benefits, it is important to acknowledge the areas, which contribute to the community as a whole:

- *Net Energy Efficiency improvements*

Both existing and new applications that result from improved communications, contribute to an overall improvement in energy efficiency

- *Operational Benefits to Utilities*

Improved communications can yield a more efficient operation within and between the utilities and third parties.

- *Improved User/Consumer Awareness*

Social benefits are achieved through better integration of distribution, metering and consuming devices. The way consuming devices are monitored and controlled influences the end users use and consumption of energy, which also contributes to both energy efficiency and utility operation.

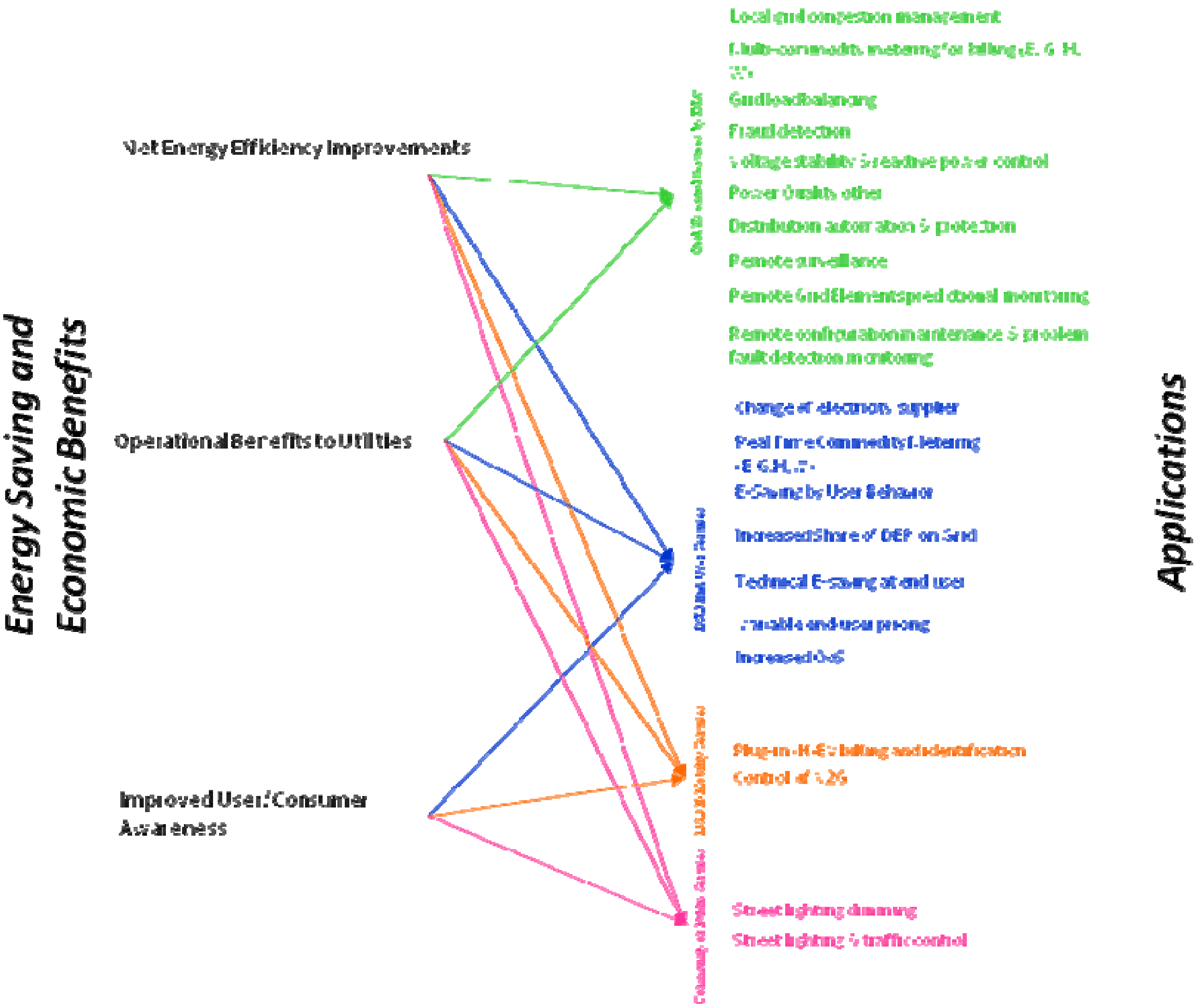


Figure 3 Links from Energy Saving and Economic Benefits to Applications

1.1.3. Applications and DLC Communication Services

Applications are group into 4 major categories.

- Grid Essential Services
- DSO End User Services

- DSO E-Mobility Services
- Community or Public Services

The following provides a brief description of each application use case :

1.1.3.1. Grid Essential Services

- Local Grid congestion management
- Multi commodity metering for billing (E,G,H,W)
- Grid load balancing
- Fraud detection
- Voltage stability & reactive power control
- Power quality
- Distribution automation & protection
- Remote Surveillance
- Remote Grid elements prediction monitoring
- Remote configuration maintenance & problem fault detection

1.1.3.2. DSO End User Services

- Change of electricity supplier
- Real time commodity metering
- E-saving by user behaviour
- Increased share of DER on grid
- Technical e-saving at the end user
- Increased QoS

1.1.3.3. DSO E-Mobility Services

- Plug in (H)EV billing and identification
- Control of V2G

1.1.3.4. Community or Public services

- Street lighting dimming
- Street lighting and traffic control

Figure 4 illustrates links to a consolidated set of Application services.

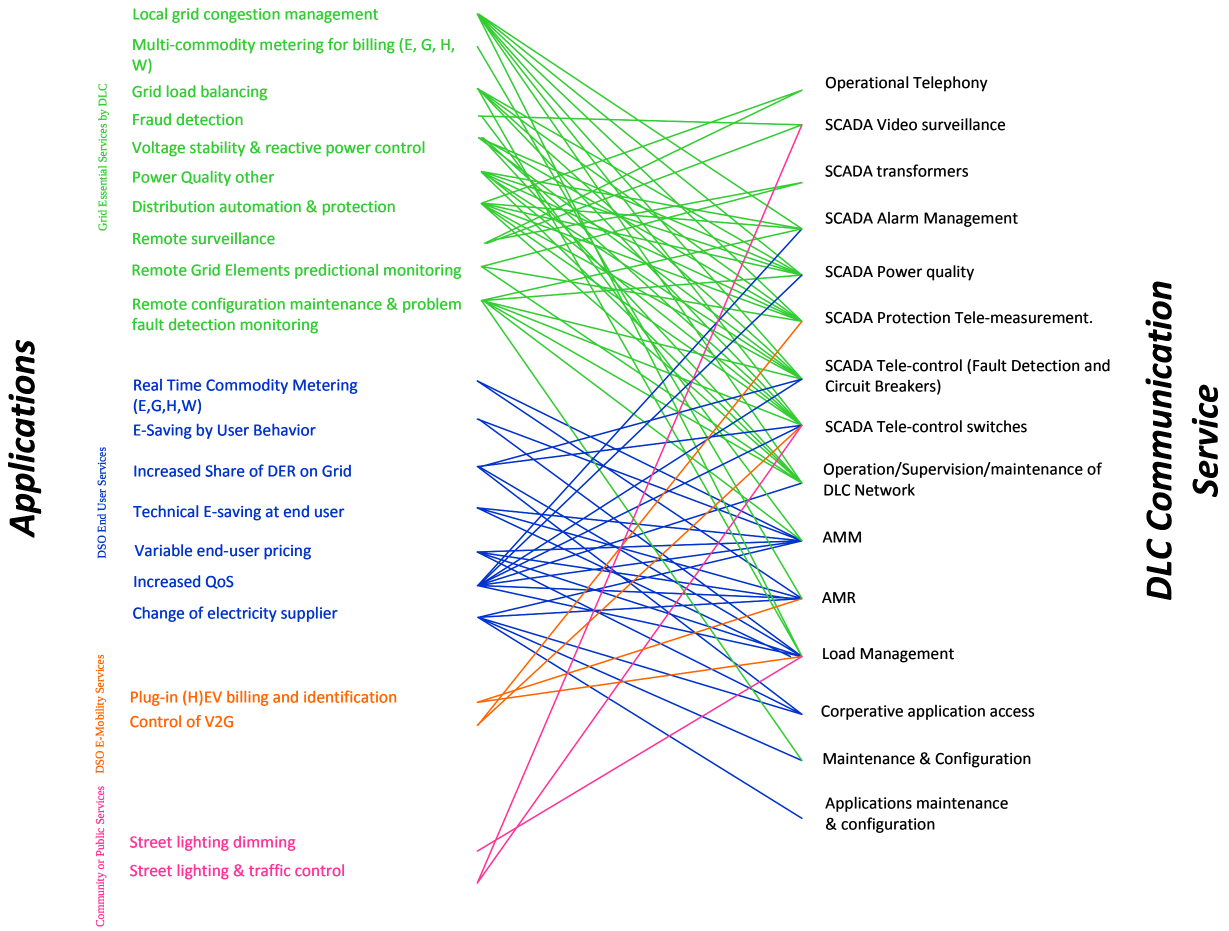


Figure 4 Links between Applications and Communication Service

2. Combined Use Cases and DLC Communication Service scenarios

The following describes a subset of linkages that provide the widest coverage of Energy Saving & Economic Benefits and Application Services by DLC.

2.1. Grid Essential & DSO End User Services

This section shows two application use cases, which cover grid essential and DSO End User Services.

2.1.1. Operational Scenario 1

Rationale: This covers a large number of DLC-VIT4IP support modes (7 modes) and these modes control key areas i.e. Demand side response and distribution generation, resulting in local grid congestion management.

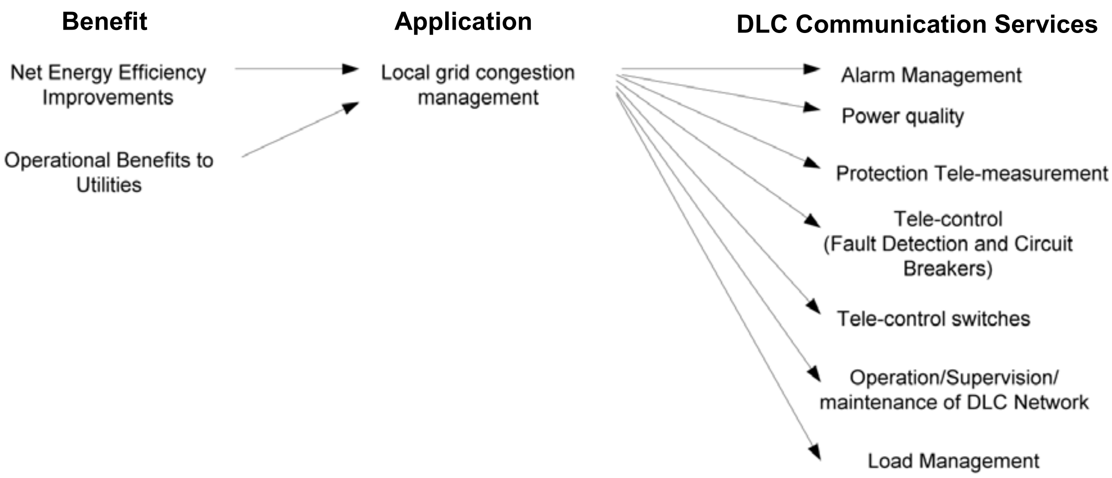


Figure 5 DLC-VIT4IP support in Local grid congestion management

Scenario 1 describes processes to monitor, identify and mange congestion within the local grid supported by DLC-VIT4IP, resulting in gaining grid level benefits shown in Figure 5.

Scenario 1	DLC Communication Service	Processes	DLC-VIT4IP Support
Occurrence of Local Grid congestion	Alarm Management	SCADA functions detect an alarm condition within the local grid	Manage Data Acquisition by Informing other node of the local grids electricity demand Identify priority level
	Power Quality	SCADA functions monitor voltage levels, voltage interruptions, frequency of interruptions and voltage dips.	Manage Distributed generation by controlling low capacity power generation

Scenario 1	DLC Communication Service	Processes	DLC-VIT4IP Support
	Protection Tele-measurement	SCADA remote measurements for identifying developing faults within the local grid.	Generate reports Generate request to isolate fault developing areas.
	Tele – Control (Fault Detection and Circuit breakers)	SCADA remote monitoring and control circuit breakers	Generate reports Inform Central services
	Tele-Control switches	SCADA remotely control switches (open/close) within the local grid	Notify developing issues with the multimode network
	Operation/Supervision/maintenance of DLC Network	Monitor DLC transmission quality and reception Quality within the local grid. - Frequency, Harmonics, and distance coverage.	Transmission modes, Throughput, Delays
	Load Management	Monitor electricity supply and demand	Billing and pricing

Table 3 Initial information for draft Scenario 1

2.1.2. Operational Scenario 2

Rationale: Since the local grid is made up of many remote elements, it is essential to monitor developing faults in parts of the grid to maintain continuous supply to the consumers.

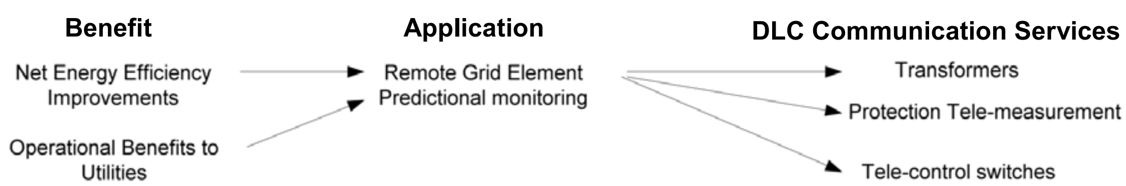


Figure 6 DLC-VIT4IP support in remote grid element predictional monitoring

Scenario 2 describes processes to remotely monitor, identify and mange grid elements within the local grid supported by DLC-VIT4IP, resulting in gaining net benefits shown in Figure 6.

Scenario 2	DLC Communication Service	Processes	DLC-VIT4IP Support
Remote grid element predictional monitoring	Transformers	SCADA manage transformer faults and sub-optimal performance.	Generate reports -Inform field engineers
	Protection Tele-measurement	SCADA remote measurements show developing faults within the local grid elements	-Generate situation updates and inform central services - Generate request to isolate fault developing elements
	Tele- Control switches	SCADA remotely control switches (open/close) within the local grid	Manage fault developing elements

Table 4 Initial information for draft Scenario 2

2.2. End User, Community and Public Services

This section shows two application use cases based on end user, community and public services.

2.2.1. Operational Scenario 3

Rationale: This end user scenario covers large number of DLC-VIT4IP support modes (9 modes). Additionally QoS based scenario address two key areas within the local grid, i.e. QoS of the DLC duplex communication within the local grid and also the QoS of the power delivery for end user. Please note that QoS here is defined as the Quality of grid service delivery and not the quality of service of the DLC Communication Service.

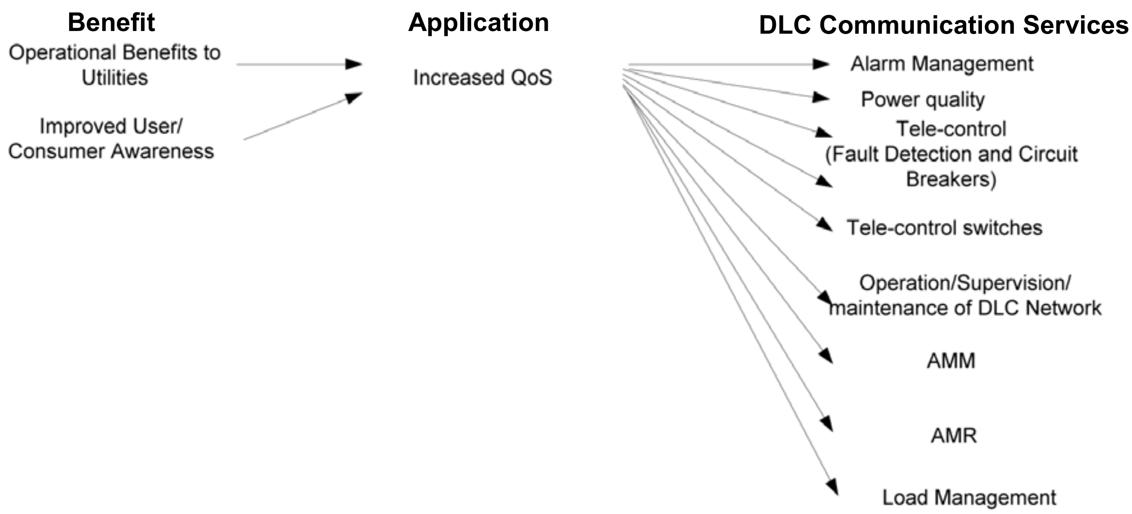


Figure 3 - DLC-VIT4IP support in remote grid element predictional monitoring

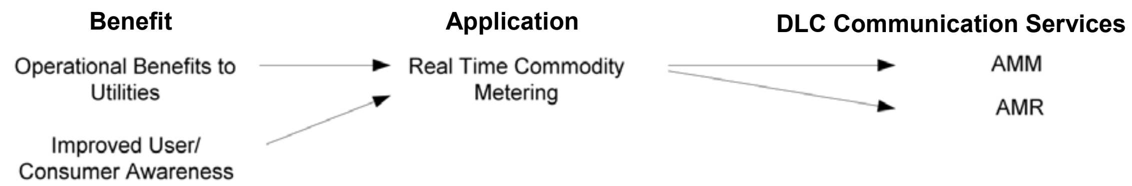
Scenario 3	DLC Communication Service	Processes	DLC-VIT4IP Support
Increased QoS	Alarm Management	SCADA detects an alarm condition within the local grid	Manage DR by Informing other node of the local grids electricity demand -Identify priority level
	Power Quality	SCADA monitor voltage levels, voltage interruptions, frequency of interruptions and voltage dips.	Mange Distributed generation by controlling low capacity power generation
	Tele – Control (Fault Detection and Circuit breakers)	SCADA remote monitoring and control circuit breakers	Generate reports
	Tele- Control switches	SCADA remotely control switches	Manage fault

Scenario 3	DLC Communication Service	Processes	DLC-VIT4IP Support
		(open/close) within the local grid	developing elements
	Operation/Supervision/ maintenance of DLC Network	Monitor DLC transmission quality and reception Quality within the local grid. - Frequency, Harmonics, and distance coverage.	Transmission modes, Throughput, Delays
	AMM	Gather technical data from AMR customers	Manage technical data
	AMR	Remotely read customer meters	Billing and pricing
	Load Management	Monitor electricity supply and demand	Billing and pricing

Table 5 Initial information for draft Scenario 3

2.2.2. Operational Scenario 4

Rationale: This scenario covers 2 DLC Communication Services and directly interacts with the end user.



Scenario 4	DLC-VIT4IP Mode	Processes	DLC-VIT4IP Support
Real Time Commodity Metering	AMM	Technical data collection from AMR customers	-Manage technical data -Maintenance
	AMR	Remotely read customer meters real time	Billing and pricing

Table 6 Initial information for draft Scenario 4

2.3. Elaborated DLC Communication Service Scenarios

The following describes in short form, the communication services by DLC which are the subject of the operational scenarios as described above. A short description is given indicating a typical communication transaction that would typically occur for each communication service.

2.3.1. Alarm Management

An alarm is the consequence of detection of an event that requires attention of the entire control system that is the SCADA system and Substations. It may have various causes, i.e. failure of a component within the local grid or remote control system or an anomaly within the grid.

> *Scenario A - A Substation controller detects an alarm condition, and transmits that information to the SCADA system. The SCADA system transmits commands to substation controllers to take remedial action. (Supervisory Control and Data Acquisition)*

2.3.2. Power quality

Power quality is described as conformity of voltage to certain standards. Deviation from these standards is regarded as degradation of power quality. Requirements can be set for variations in the peak or RMS voltage, voltage spikes, waveform shape, symmetry of the waveform between different phases, etc.

When energy storage is used to assure continuity of quality power, stored energy is only applied for seconds or less, as needed.

Monitor power quality within the local grid by measuring voltage levels, voltage interruptions, frequency of interruptions and voltage dips.

Scenario B – Substation controllers measure voltage levels, voltage interruptions, frequency of interruptions and voltage dips, and transfer information to the central SCADA system. (Data Acquisition)

2.3.3. Protection Tele-measurement

Support remote tele-measurements within the local grid in order to protect the grid from perturbations by isolating the faulted part from the rest of the network.

The main objective of a protection scheme is to keep the power system stable by isolating only the components that are under fault, whilst leaving as much of the network as possible still in operation. Protection devices operate autonomously, without the need to control them. Monitoring the status is required for reporting and alarming only, not to ensure grid stability.

Scenario C – SCADA system monitors remote protection devices. (Data Acquisition)

2.3.4. Tele-control (Fault Detection and Circuit Breakers)

Support remote monitoring and fault detection within the local grid, control breaker and switch state.

Scenario D – SCADA Systems monitor the status of breakers and sends control commands. (Supervisory Control and Data Acquisition)

2.3.5. Tele-control switches

Substation can remotely control switches (open/close) within the local grid.

Scenario E – SCADA Systems monitors the status of switches, and sends control commands. (Supervisory Control and Data Acquisition)

2.3.6. Operation/Supervision/maintenance of DLC Network

Communications, monitoring, measurement, analysis and information technology links are central to the effectiveness of real-time grid operations, especially with respect to the smart grid and the integration of diverse resources into power system operations. These operations are exclusively to optimise the transport processes through the grid.

Scenario F – The central SCADA system acquires and processes measurements from devices all through the grid. Several components within the grid, e.g. Breakers, Switches, Protection Devices, are controlled by the central SCADA. (Supervisory Control and Data Acquisition)

2.3.7. Load Management

The generation and the consumption of electricity must be balanced. The generation can easily be controlled; the consumption can be controlled to a certain degree. Controlling the consumption can e.g. be achieved through price shifts, or by interrupting the power supply.

Scenario G – Price information is transferred to consumer's devices (e.g. smart meters), switch commands are transferred to consumer's devices. (indirect Supervisory Control)

2.3.8. AMM

Automatic Meter Management (Smart Meter) is another expansion of remote system that includes possibility of performing technical measurements and functions and carrying out customer-oriented services via the system.

Scenario H - Tariff information is transferred from a central registering system to a smart meter device at a consumers premise. (indirect Supervisory Control)

2.3.9. AMR

AMR is a remote reading system based on an advanced technology that permits utilities to read electronic meters over long distances. Through AMR, the energy consumption can be read on an annual, monthly, weekly, daily, hourly, or more frequent basis. Common reading interval is once every five minutes.

Scenario I – Meter readings are transferred from smart meter devices at the consumers premises to a central registering system. (Data Acquisition)

3. System requirements

3.1. Environmental Requirements

3.1.1. Characterisation of the network

Before the electricity is consumed by the end-user it has passed several stages: generating the electricity in power plants, transmission and distribution of the electric energy over the electrical grid.

Power plants convert primary energy (coal, oil, natural/bio gas, nuclear) and renewable energy (wind, sun, hydro..) into electric energy. The generated electricity goes through various transformations; e.g. stepping up the voltage in order to transmit over large distances and various levels of stepping down the voltage to its final end-user (domestic, commercial, or industrial use). After generation in power stations, electrical energy needs to be transported to the areas where it is consumed. This transport is more efficient at higher voltage, which is why power generated at 10 - 30 kV is converted by transformers into typical voltages of 220 kV up to 400 kV, or even higher. Since the majority of electrical installations operate at lower voltages, the high voltage needs to be converted back close to the point of use. The main reason to step down voltage is to increase the safety for the end user and insulation material. The first step down is transformation to 33 - 150 kV. It is often the level at which power is supplied to major industrial customers. Distribution companies then transform power further down to the consumer mains voltage.

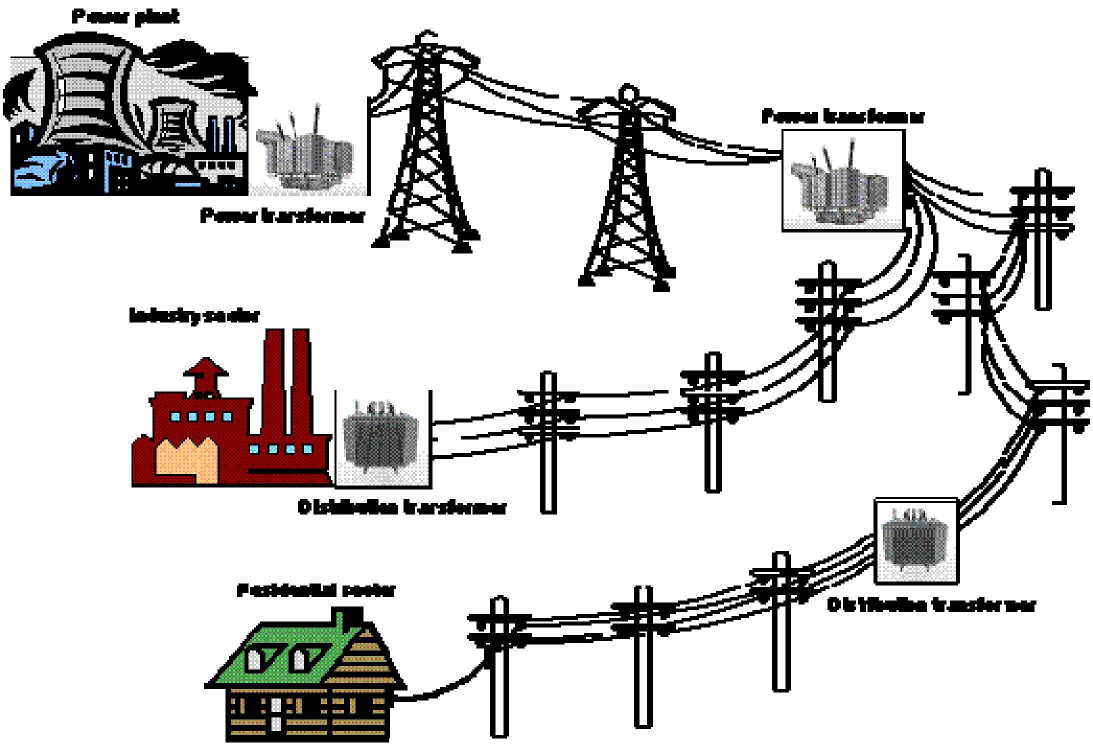


Figure 7 Overall context is the electricity and transmission distribution (T&D) system

In this way, electrical energy passes through an average of four transformation stages before being consumed. A large number of transformers of different classes and sizes are needed in the transmission and distribution network, with a wide range of operating voltages. Large transformers for high voltages are called power transformers. The last transformation step into the consumer mains voltage (in Europe 400/230 V) is done by the distribution transformer.

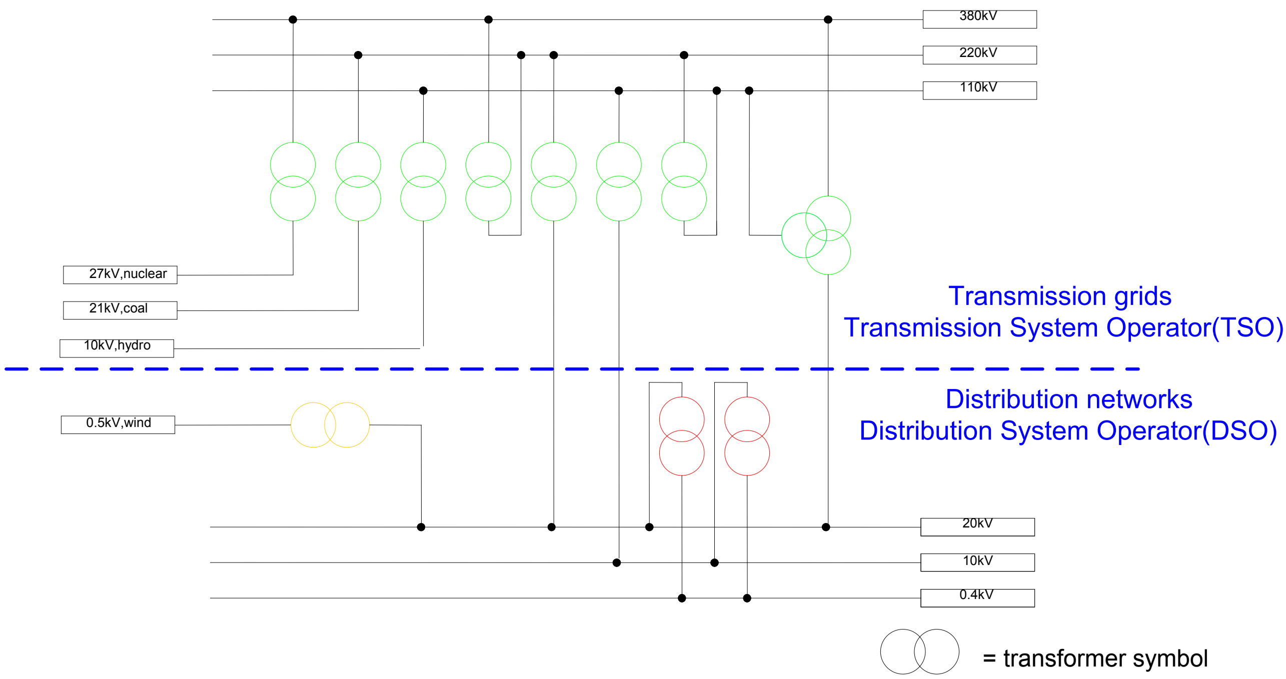


Figure 8 Schematic diagram of the electrical Transmission and Distribution (T&D) system (voltage level typical for Germany but can differ per country)

The configuration of the power distribution network depends on the deployment of electrical load of consumer, geography of the service area, concepts concerning the power-system operation, and those concerning protection in the event of a system fault.

The power distribution network is designed for the efficient transfer of power at 50 or 60 Hertz. While this type of system works well for the distribution of power at power line frequencies, it presents certain challenges when used as a communication system. The considered DLC communication is primarily applied to the distribution grid.

The **Distribution Grid** distributes the electric energy to the customers. The distribution network consists of the medium and low voltage network.

The **Medium Voltage (MV) Network** distributes the electric energy to the secondary distribution substations. The European medium voltage (MV) is usually between 1 and 60 kV.

The **Low Voltage (LV) Network** distributes the electric energy from the secondary distribution substations to the low voltage customers. The voltage (LV) is below 1 kV.

For MV system configurations, systems typically employed are open loop, including loop topologies, which are typically opened in one place by an automatic switch or manual, and tree-like topology systems, which include radial distribution line. Depending on the way the electrical loads are distributed, distribution line types and lengths vary from power system to system.

For LV systems, the methods of wiring vary from one service area to another, such as single- phase three-wire wiring, single- phase two-wire wiring, tri-phase three-wire wiring, and tri-phase four-wire wiring.

To use distribution systems as communications paths, signal coupling units with which to inject and extract DLC signals on those lines are necessary, with a choice of Capacitive Coupling Unit (CCU) and Inductive Coupling Unit (ICU) options.

Therefore, Power Communication over Distribution Grid requires considering some of its **natural attributes**:

- The **topologies** of Distribution Grid.
- There may occur temporary or even permanent **interruptions** of the phase conductors caused by opened power switches.
- A wide range of Power **wire and cable types** is used (aerial wires and cables, earth cables with grounded shield, plastic-isolated and oil filled cables).
- The distribution line is subjected to **various kinds of interference** (signal attenuation, signal distortion, noise, etc.) (see section 3.1.4)

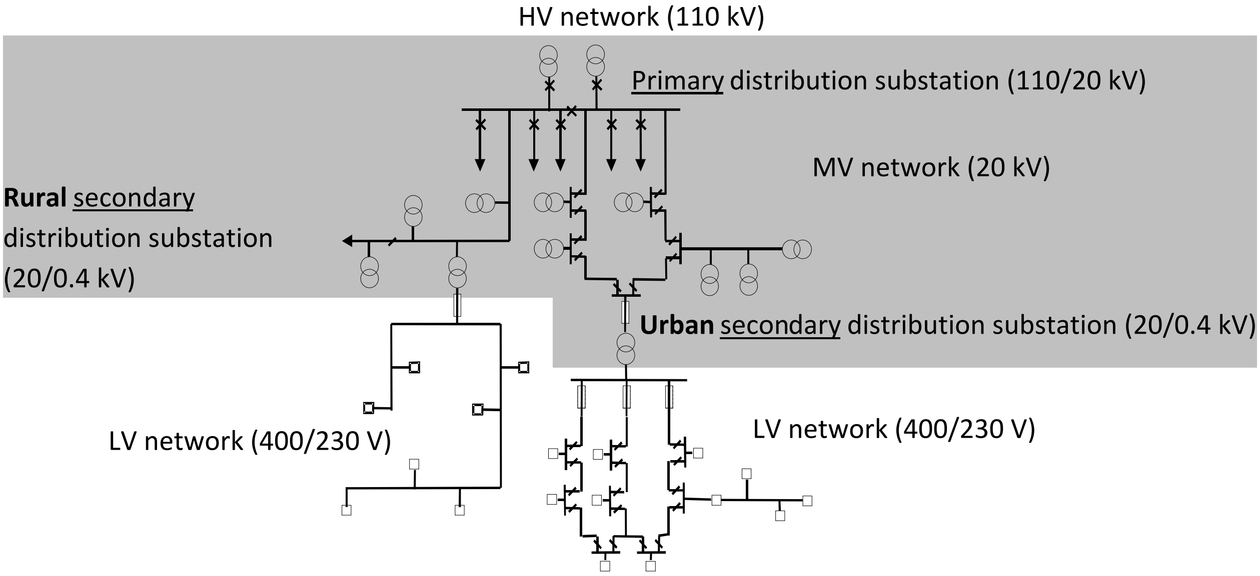


Figure 9: *Typical European topology for Distribution Grid*

3.1.1.1. Characteristics of Network Segments, Transformers and Loads

The project team prepared a global overview of MV and LV grid characteristics in the EU27 countries, and Israel. This overview is not meant to be a complete inventory of all existing forms of MV or LV grid. It is based on data gathered over the last ten years. The characteristics of a **typical MV grid** are as listed in the following table that is a summary of the more detailed information in appendix 6.1.1:

MV network	Characteristic	EU 27 Typical*
Overhead MV lines	Type	Aluminium single wire - bare conductor
	Lengths	500 … 1500m
Underground MV lines	Type	Aluminium - XLPE insulated / single- & multi-core
	Lengths	500 … 1500m
HV/MV substation	Transformer ratings	10 … 63 MVA
	HV ranges	70 … 400 KV
	MV ranges	6 … 26 KV
	#MV feeders/transformer	5 … 15 ??
MV grid	Topology	Radial/Ring/Networked
	Interconnections	Yes
	Control of interconnection	Remote control
	Voltage regulation	Automatic tap changer
	Neutral	Earthed/Peterson coil/Insulated
	Balanced	Yes
	Security	n-1
		* scope: urban and rural areas

Table 7: Summary of characteristics of a typical MV grid according to EU27

- In general, HV/MV transformers ratings are between a few MVA and 200 MVA. HV/MV transformer ratings between 10 and 63 MVA are most common. These transformers convert the high voltage (mainly between 63kV and 400 kV) of the transmission network to the Medium Voltage level (typically between 6kV and 26kV) of the MV distribution network. All European countries use automatic tap changers for voltage regulation.

- The three main MV topolgies are radial (rural areas), ring (urban areas) and networked (urban areas) topologies (see 2.1.2). The networked topology is most common, however they operate as radial topolgies opening certain stretches of the network.

- The neutral of the MV network can be directly earthed, earthed via an impedance or a tuned circuit (Petersen coil) or isolated. In some countries, all three earthing systems exist.

- Aluminium cables are most common for overhead lines because aluminium is lighter and less expensive for a given current capability regarding to copper. The centre of the aluminium cable is made of steel to get a better strength required to support the weight without stretching the aluminium. The bare (un-insulated) wire is the most common type used in MV overhead lines. In some areas insulated (PE, XLPE…) MV overhead lines are used for safety reasons. Insulated (PE, XLPE, PILC,…) single-core and multi-core cables are used as MV underground cables.

- Typical length of the MV cable is about 0.5 to 1.5 km

- Three types of MV switchgears are generally available: Load-break switches and separate MV fuses, load-break switches with integrated MV fuses and circuit-breakers.

The characteristics of a **typical LV grid** according to EU27 are as follows which is a summary of the more detailed information in appendix 6.1.2:

LV network	Characteristic	EU 27 Typical*
Overhead LV lines	Type	Al (bare & insulated) / single- & multi-core
	Lengths	50 … 1000m
Underground LV lines	Type	Al - XLPE insulated / single- & multi-core
	Lengths	50 … 1000m
MV/LV substation	Transformer ratings	20 …. 1000 kVA
	MV ranges	6 … 26 kV (20 kV)
	LV ranges	230Vac/400Vac
	Residential/Industrial	75%
	#LV feeders/transformer	5 … 15
	Distance between substations	50 … 400m
LV grid	Topology	Meshed (radial operated)
	Interconnections	In urban areas
	Control of interconnection	Manual
	LV Feeder protection	Fuse
Connections	1Ph/3Ph	Both
	Accounts/transformer	50 … 300
	Accounts/LV feeder	5 … 30
	kWh meter	Inside the building (exterior in some countries)
		* scope: urban and rural areas

Table 8: Summary of characteristics of a typical LV grid according to EU27

- MV/LV transformer ratings vary from 20 kVA (rural areas) until 1000 kVA or even more (urban areas). The average MV/LV transformer (250-400 kVA) feeds about 5… 15 LV feeders with about 5 to 30 households connected to each LV feeder. Each LV feeder is protected against overload and short circuit currents by fuses (in most cases) or circuit breakers.

- Most of the LV networks are meshed structured. However, they are very often operating in radial mode (see 3.1.2.3 Low Voltage Network)

- The low-voltage distribution network is realised by overhead lines or underground cables: overhead lines are used in rural areas whereas underground cables are more common in urban areas. The lengths (from the MV/LV transformer to the furthest home connection point) of the LV lines and cables vary from some tenths to some hundred of meters (mostly shorter than 1 km). Aluminium is more and more used as conductor material.

- The distribution of the LV can be 3 phase 4 wire (earthed neutral) 230/400 VAC or single-phase two-wire 230 VAC. In most of the EU 27 countries 3 phase LV distribution is applied, in a few countries single phase distribution is forming a important part of the LV grid (for example Ireland)

- 2- core (single phase) and 4-core (3 phase with neutral) self supporting insulated aluminium cables are frequently used as overhead lines but bare copper and aluminium conductors are also existing in some countries. Typical lengths differ from some tenths to some hundred of meters with sections from 16mm² until 150mm².

- XLPE (cross linked polyethylene) insulated single-core and multi-core aluminium cables are mostly used as underground LV cables. Typical lengths differ from some tenths to some hundred of meters with sections from 16mm² until 630mm².

- Restoration following a supply interruption by reconfiguration of the LV network is available in urban areas. Reconfiguration can be done by remote control of an interconnection switch or via manually using switchgears which are not remotely controlled.

- Street lighting can be connected to separate wiring or directly on the residential distribution lines. A typical number of street lights per transformer station is 13 on average (in Belgium: 56).

- LV consumers are normally supplied according to the TT or TN system. A TT system requires a residual current earth-leakage protective device. For a TN system an overcurrent protection by circuit-breaker or switch fuse is required.

- Individual LV connections can be done by an overhead or underground cable, depending on the existing LV network. The main circuit breaker (with a residual current earth fault protective device for a TT earthing system) and KWh meter can be located inside or outside the building. The consumers circuits are individual protected by fuses (in older installations) or miniature circuits breakers.

- The MV/LV distribution transformer has on it's LV side up to 300 households[1] connected and each household is expected to contain one MUC (Multi Utility Controller), that is actually the gateway between meters and utilities (see also section 3.2.2.2, "Smart Meters / MUC"). All the meters (electricity, gas, cold water, hot water, heating) are connected to the MUC. So, it is reasonable to assume, that one household contains at least one electricity meter. That means, that maximum number of electricity meter at one transformer station is 300. If we consider that every household contains 5 meters (electricity, gas, cold water, hot water, heating) then the overall number of meters per transformer station will be 1500]. A typical number of 200 MUCs per transformer station is expected.

[1] The term "household" does not refer to the buildings (which may contain tens of apartments), but to every apartment, that is monitored by a separate meter.

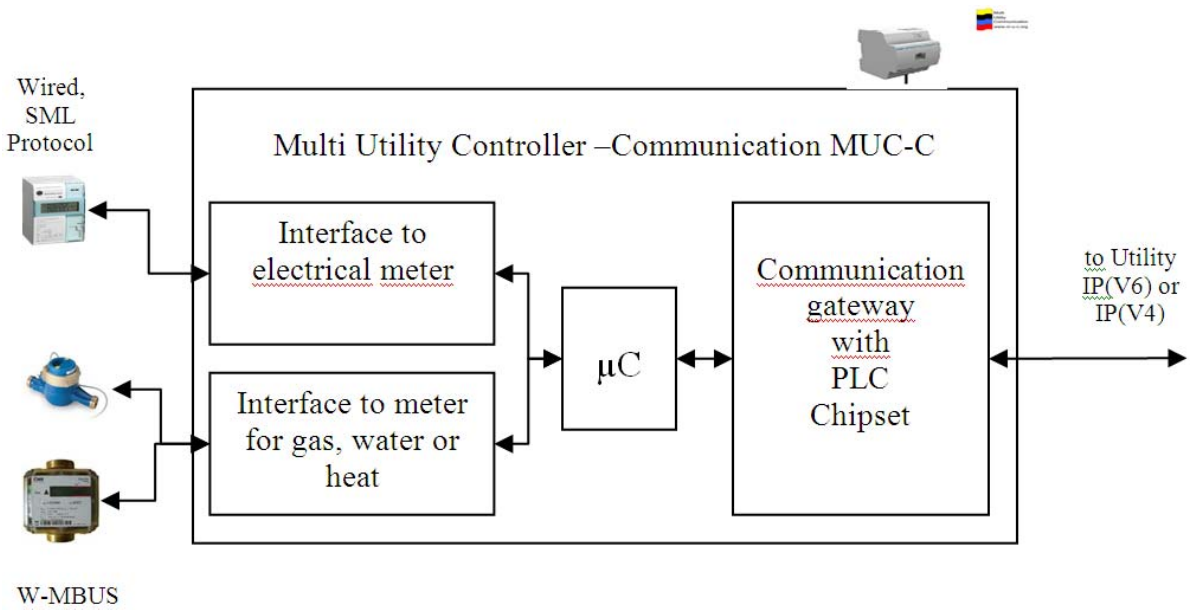


Figure 10: Overview MUC-concept as a communication link for commodity meters

3.1.2. Topologies of the communication network

3.1.2.1. Powerline Network

The topology of the high voltage network is commonly a closed ring topology with a few cases of open ring topology. The medium voltage network is laid out mainly as an open ring topology, with a few cases of star topology for both urban and rural areas. The low voltage network is an open ring topology for urban areas and star topology for rural areas (Rempli 1-1, 2003).

3.1.2.2. Medium Voltage Network

There are some different structures used in a MV Distribution Network construction. These are shown in the following figures.

a) Basic radial system

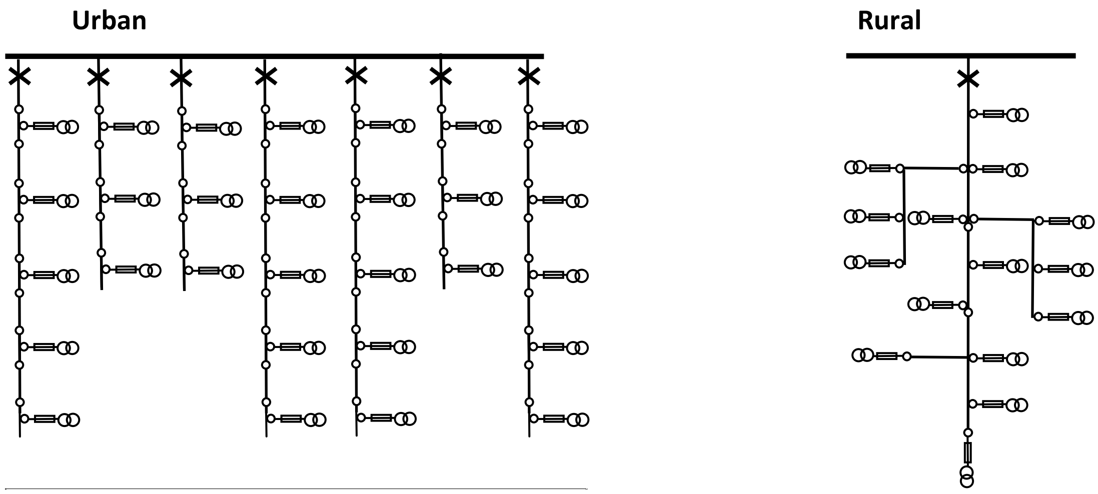


Figure 11: MV network topologies - basic radial system (left: urban, right: rural)

b) Open loop system

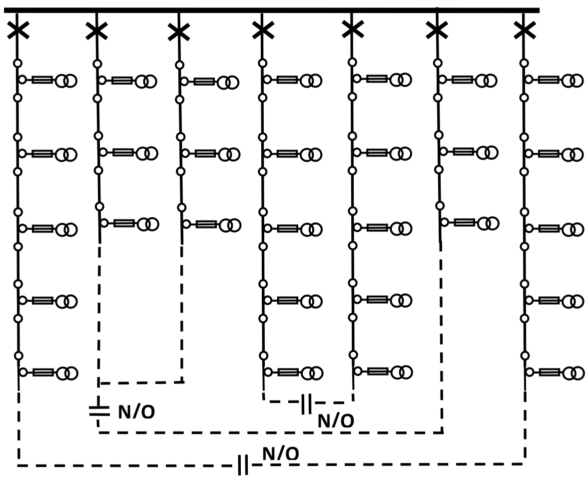


Figure 12: MV network topologies – open loop system

c) Link arrangement system

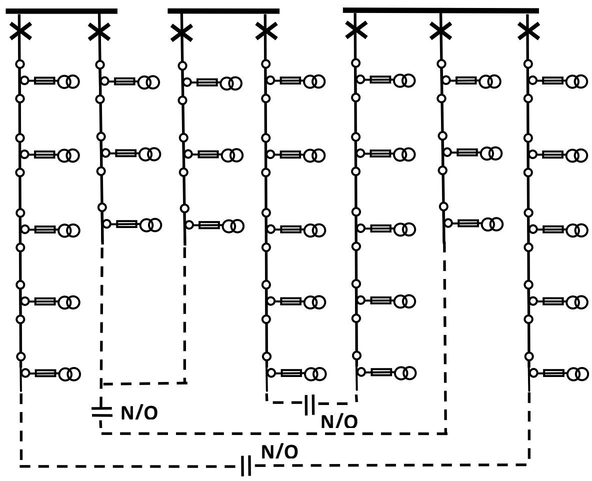


Figure 13: MV network topologies – link arrangement system

d) Closed loop system

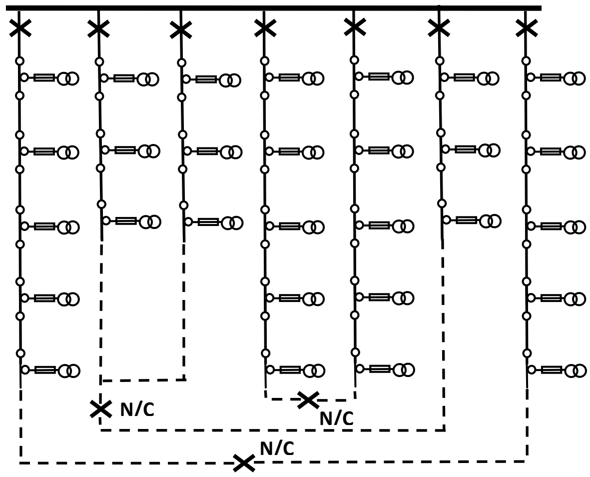


Figure 14: MV network topologies – closed loop system

e) Primary network system

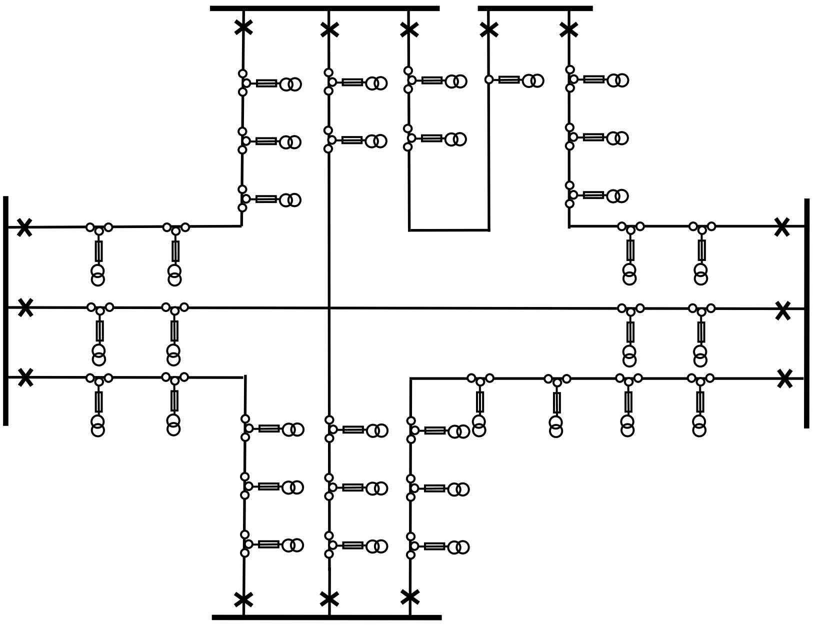


Figure 15: MV network topologies – primary network system

f) Satellite network

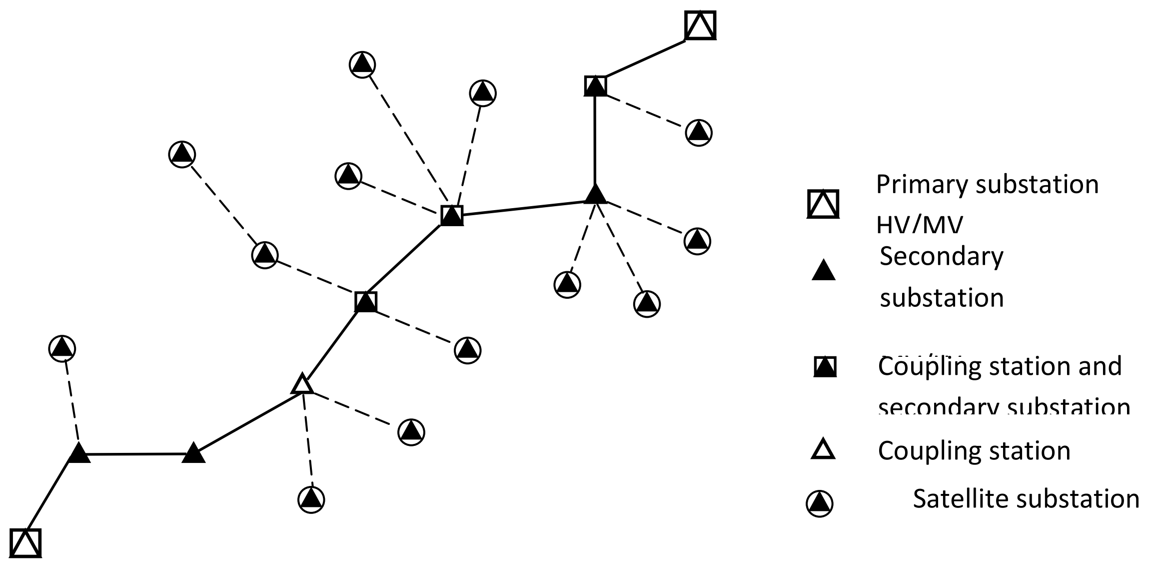


Figure 16: MV network topologies – sateliite network

g) Mesh network

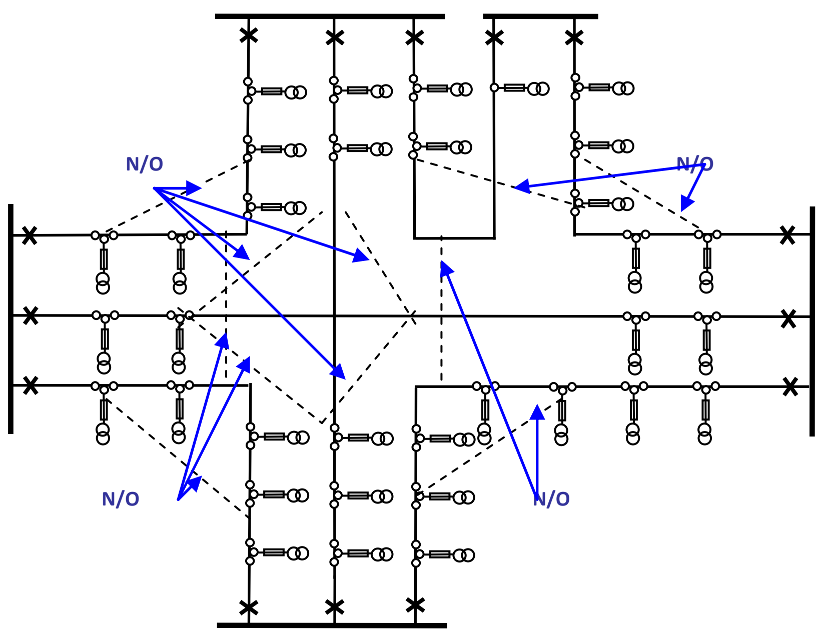


Figure 17: MV network topologies – mesh network

Annotations to the figures:

- X: breakers
- o-o-o = active element to bypass transformer
- N/C – normally closed
- N/O – normally opened
- The "fuse" symbols beside the transformer represent overload/overcurrent MV side protection as well as a fault upstream protection from the transformer in case of the fault upstream of the LV protections.

This mesh network structure is used for the urban and suburban areas as well as for the rural one in order to ensure high survivability of the MV Distribution Grid and avoid local blackouts by passing the damaged parts of this Grid as well the parts under the maintenance.

The mesh concept could be implemented for all the MV structures illustrated above.

As a result, DLC system shall be adaptive to recognize and react on the MV Grid reconfigurations adopting DLC data routing through the Distribution Grid reconfigured periodically.

The following figure illustrates an example for a modern mesh MV (22 kV) Grid (which will be provided by IEC for the DLC+VIT4IP test bed).

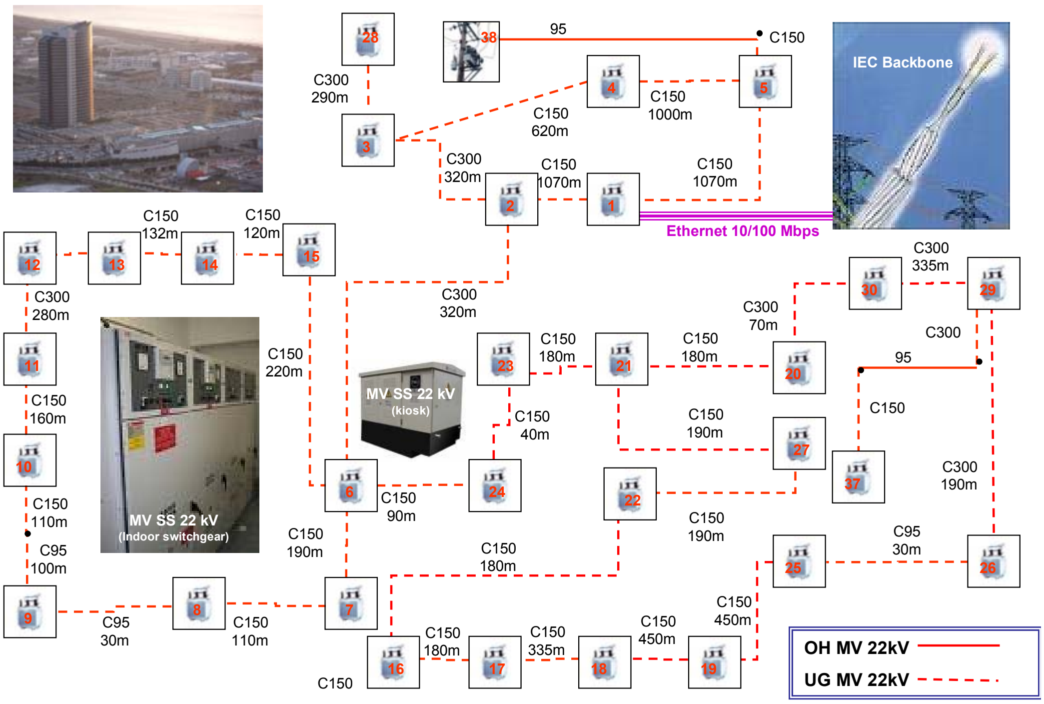


Figure 18: example for a modern mesh MV grid

3.1.2.3. Low Voltage Network

The old fashioned topology of a low voltage distribution network is typically radial.

The modern topology of a low voltage distribution network is meshed and similar to the most of the MV structures illustrated above.

The LV consumers fed from the main MV/0.4 kV transformer whilst the alternative neighbour ones are disconnected from this LV feeder by the LV breaker, but feeding the other neighbour LV feeders. Additionally, each LV feeder is constructed with a number of loops reconfiguring manually. Usually and in contrary to the MV circuit breakers operations, the LV grid reconfigurations are performed by the fuse replacing into the street cabinets.

This mesh LV structure is used for the urban and suburban areas as well as for the rural one in order to ensure high survivability of the LV Distribution Grid and avoid local blackouts by passing the damaged parts of this Grid as well the parts under the maintenance and overload.

Concerning quantity of the consumers fed from the same MV/0.4 kV transformer, consumer density shall be taken into account. The maximum number of the consumers fed from the same MV/0.4 kV transformer is about 100 consumers.

The low-voltage network (LVN) topography defines the topology of the PLC network. However, the LVN network differs from country to country. Respective network characteristics are summarized in section 3.1.1.1.

An example of the LVN topology is shown in Figure 19.

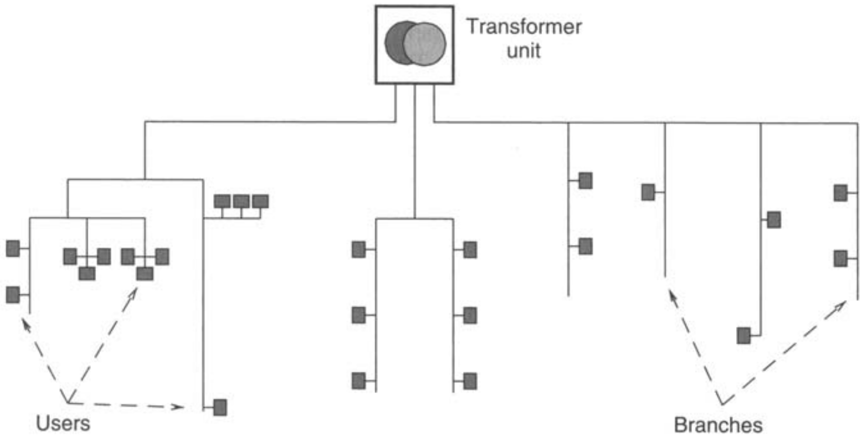


Figure 19: Possible topology of a low-voltage supply network (H. Hrasnica, 2004)

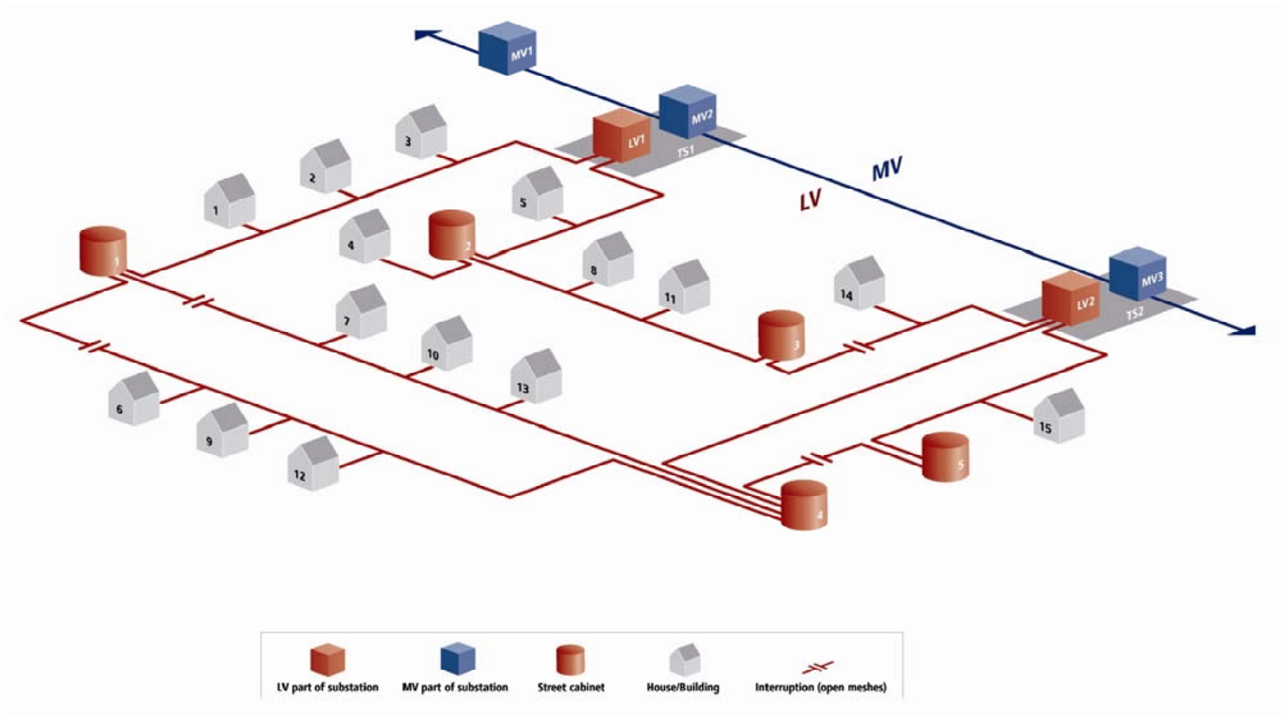


Figure 20: Schematic power grid topology

3.1.2.4. Backbone Network

As the DLC system is classified as an access communication system, the backhaul connection is required to connect the DLC cluster with the utility IT core.

Private and public broadband telecommunication networks based on IP could provide the required backhaul Ethernet connection and service redundancy. Since the considered DLC system is a high-speed one, the broadband network is required to serve a lot of the DLC clusters.

Private fiber optic owned by the power utilities is preferred against public alternatives (e.g. GPRS) for the reasons of availability, reliability, security, cost, latency, etc.

3.1.2.5. Connection between Powerline and Backbone Network

One of the MV DLC components within each DLC cluster is used as an Access (Injection) Point to mediate between this DLC cluster and backhaul. This can be seen in the following Figure 21which gives an idea of the conceptual architecture of the envisaged system.

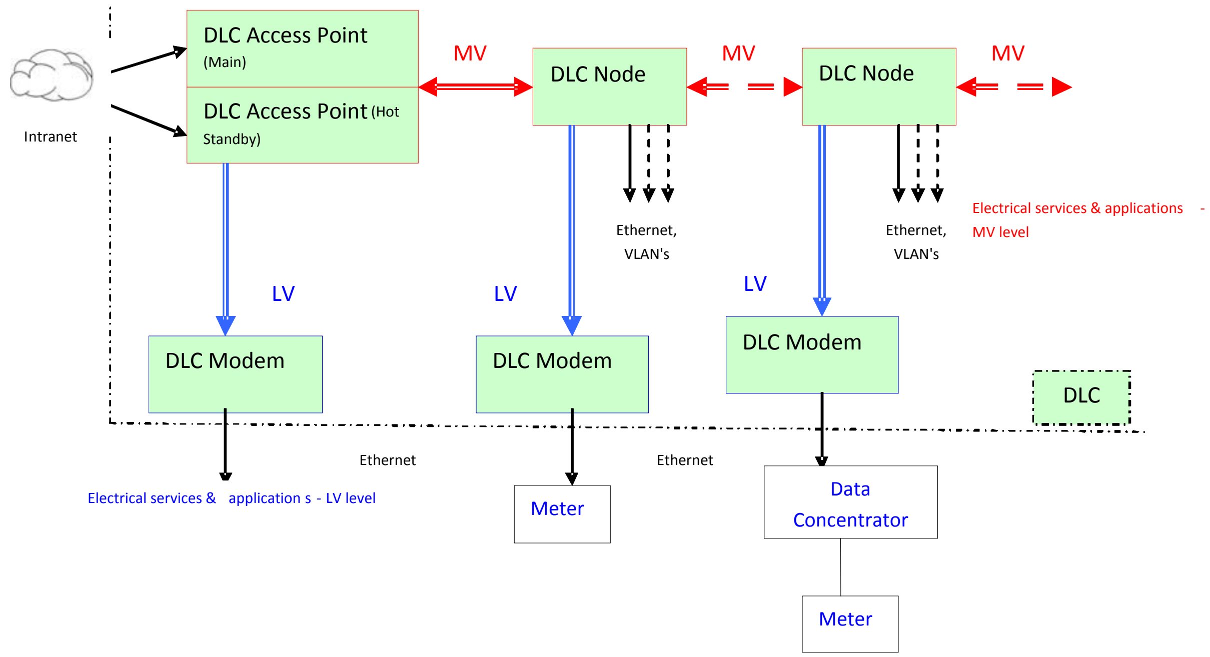


Figure 21 example for conceptual architecture

As Access Points represent central components in DLC clusters redundancy shall be provided, e.g. by deploying Access Points as redundant DLC components consisting of a main and hot-standby unit or by providing access to each node via more than one Access Point (see also section 3.2.3.3)

The placement of an Access point has to consider availability of broadband connections on the one hand and sources of high interference (e.g. by corona effect or partial discharge) on the other hand.

3.1.3. Dynamic changes of topologies

In order to follow the possible dynamic topology changes in an electrical network, the DLC communications network and equipment must be capable to follow these changes. If a communication link is lost due to a dynamic topology change (or connectivity change), a new communication path must be dynamically setup through alternative routes.

The cause for such a change can be broadly segregated into the following groups:

- Maintenance and organised reconfiguration of the network
- overloads
- failures, e.g. equipment that fails
- external reasons, e.g. a cable may be pulled over by an excavator
- other or unknown reasons.

To achieve such a topology change, power switching devices like switches and circuit breakers will be manually or automatically be triggered to open or close a path. Additional to this physical reconfiguration of the power grid network, the DLC communication network must also be able to cope with external electromagnetic interference due to electrical motors and machines which may result in a lower communication link quality (increased BER, decreased bandwidth) or even communication link break down.

The frequency of occurrence of those changes can hardly be specified. However, as an approach it can be assumed that those changes do not occur more often than once a day.

DLC systems shall be able to adapt automatically to dynamic changes in network topologies due to reconfiguration of network and failures. To enable reliable communication with low latency this adaptation has to be performed in rather short time. The detailed timing requirements depend on the respective application and can be found in the QoS section of this document.

3.1.4. Channel characterisation

Since the advantage of power line communication is in the existing infrastructure of the distribution grid, **no requirements can be imposed on the transmission channel**, but it rather has to be used as it is available. Therefore, the analysis of the basic characteristics of the transmission channel is of great importance for the successful development of a power line modem (Bumiller, 2010).

Typically, a transmission channel is defined between one transmitter and one receiver. The interface of the physical transmission channel is located at the points where the analog transmission signals are coupled onto and off the mains network. The physical channel can be split into the components transmission channel and interferences, which can be described independently from each other.

The following subsections give a short summary of the main characteristics of the powerline channel and the resulting consequences for a transmission system using this channel. For further details refer to (Bumiller, 2010).

3.1.4.1. Transmission channel / Transfer function

- For design of the coupling at the transmitter the **access impedance** to the power line is very important and shows a **strong variance** for frequencies below 500 kHz. Depending on the design of the coupling unit at the transmitter different access impedances may result in different signals on the interface to power line.
- The physical channel can basically be considered as linear. Non-linear distortions, that are observed frequently, are often caused by the analog part of the transmitter, the coupling or the receiver, which are not included in this definition of the channel.
- The different degrees of saturation in transformers caused by the alternating current for power transfer result in a transfer function varying in time and do not affect the linearity of the communication signal (linear time-variant (LTV-) system).
- **Time-variance** of the transfer function is a critical issue that can vary widely in different environments.
    - In outdoor areas– mainly measured in residential areas– a **change in the transfer function** mainly only happens in case of a change in the operation or switching, in In-House areas the transfer function may change considerably by just switching on one power consuming device. If the period between two switching processes is defined as a network mode, that can last a long period of time, the transfer function is very stable and can be considered quasi-stationary. In industrial areas and occasionally in office environments with a lot of switched power supplies a jumping between two network modes with single or double network frequency can be seen. For frequencies lower than 100 kHz the attenuation differences can be frequency dependent up to 10 dB.
- Due to the characteristics of the power grid (network branches, impedance mismatching, media transitions,…) the transmission channel shows a multipath propagation of signals and hence frequency selective notches.
- The losses due to branches and reflections are a dominating influence on the transfer attenuation, particularly for lower frequencies where cable attenuation is only of secondary influence.
- The cable attenuation clearly increases with the frequency as well as with the cable length.

3.1.4.2. Noise and interferences

The noise and interference found on powerlines can be considered as a superposition of different kinds of interferences which are characterized in the following. For the individual operational environments and different frequency ranges the characteristics of these noise types may differ widely.

- Colored (background) noise
  - The power density spectrum varies slowly with time, i.e. within minutes or hours.
  - While this kind of noise is still so dominant for frequencies below 30 kHz, that this frequency range cannot be used for communication, the power spectral density is usually quite low for higher frequencies.
  - This kind of interference varies greatly depending on field and location of the application, but it is usually not the dominant interference, except for very low frequencies.
- Narrow band noise
  - Mainly consists of sinusoidal interferences and can exceed the receive signal in its amplitude by far more than 20 dB.
  - The amplitude of the interferences caused by radio stations varies with the time of day, while the other interferences depend on the operation mode of the interfering device. These are present for a longer period of time and are predictable for the transmission system.
- Periodic Impulsive Noise
  - network-synchronous impulsive noise:
    - Repetition rate of 50, 100 or 200 Hz and is synchronous to the mains voltage.
    - The power density spectrum usually decreases with increasing frequency, but can, in relevant frequency ranges, still be more than 50 dB above the power density spectrum of the background noise.
  - Impulsive noise asynchronous to the mains frequency:
    - repetition rate ranges between 50 to 200 kHz
- Asynchronous Impulsive Noise
  - occurs at random times with a duration between a few microseconds to several milliseconds.
  - The power density spectrum can often exceed the background noise considerably, often more than 50 dB, and thus also exceed the receive signal by a multiple

3.1.4.3. Typical Signal-to-Noise Ratios for Power Lines

The indicated interferences discussed above and transfer functions show that the relation between the signal- and the interference or noise power is not constant neither over frequency nor over time. Therefore it can neither be described by a spectrum, nor by a signal plot over time. The following figure should elucidate the situation for the transmission on the power supply system with short-term power density spectra (PDS).

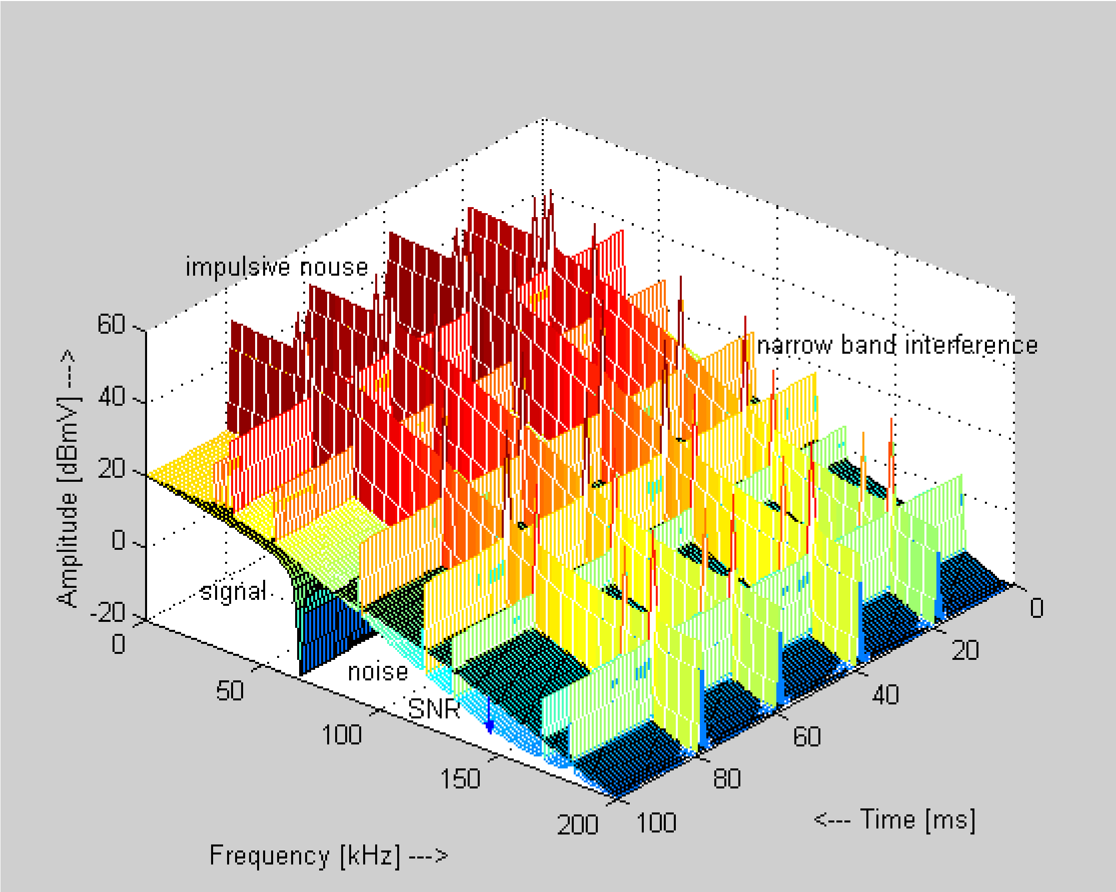


Figure 22: Signal-to-noise ratio (SNR) over time and frequency

The graph visualizes, that for the transmission only separate quadrangles remain, in which data transmission with a positive SNR can occur. Predicting the tiles with positive SNR and sharing this information between transmitter and receiver is very difficult and due to the dynamic changes of these tiles not efficient.

3.1.4.4. Consequences from channel characterisation

• the medium voltage lines are sometimes very long (e.g. 80 km) and a direct communication

from the Access Point to all participants in the network is not granted,

• and in spite of the much shorter length of a low voltage grid the attenuation is much higher due

to the high number of branches,

→ an **adequate number of repeaters** are necessary

→ an **adequate number of repeater levels** is necessary

→ a **network management** has to be designed for routing messages, i.e. **appropriate routing algorithms** are necessary

Channel characteristics change over time, often even abruptly

→ Routing has to be adapted continuously. This can only be provided by **automatic routing**.

→ **Real-time requirements** do **not allow** periods of blocked communication due to **readjustment of communication** parameters

→ Data transmission has to **reduce the influence of the interferences** by actions of signal processing and to **exterminate the remaining interferences** by the use of channel coding.

→ If the noise at the location of the receiver allows it, the **receiver should** be able to **support a high dynamic range** (60…80 dB) in the received signal.

➔ If a **long distance range** has to be achieved for transmission, the **frequency range** used for the transmission has to be chosen **as low as possible**.

3.2. Functional Requirements

3.2.1. Network Planing

The main task of network planning is taking decision about transmission technology, medium, capacity, routing strategy, etc. to be used to interconnect the network devices. The planning of the PLC networks starts with the placement of Base Stations (BS) in the low-voltage network. The number of BSs and their placement has to be calculated in order to minimize the network costs and maximize the Quality of Service (QoS). After that comes the task of users allocation to the BSs. In case of unreachable users, the optimal placement and number of repeaters must be found. If powerline communication involves two voltage levels (MV and LV) then PLC channels are allocated to the installed BSs (which are Bridges then), and the calculated network can be connected to a Wide Area Network (WAN) through the WAN Access Point (WAP) (Fig. 2.1.1) (Haidine, 2008). If only one voltage level is involved (MV or LV) then the BS is also the Access Point. For placement of the Access Point see also section 3.1.2.5.

Depending on the three-phase or one-phase users connection the planning approach is different.

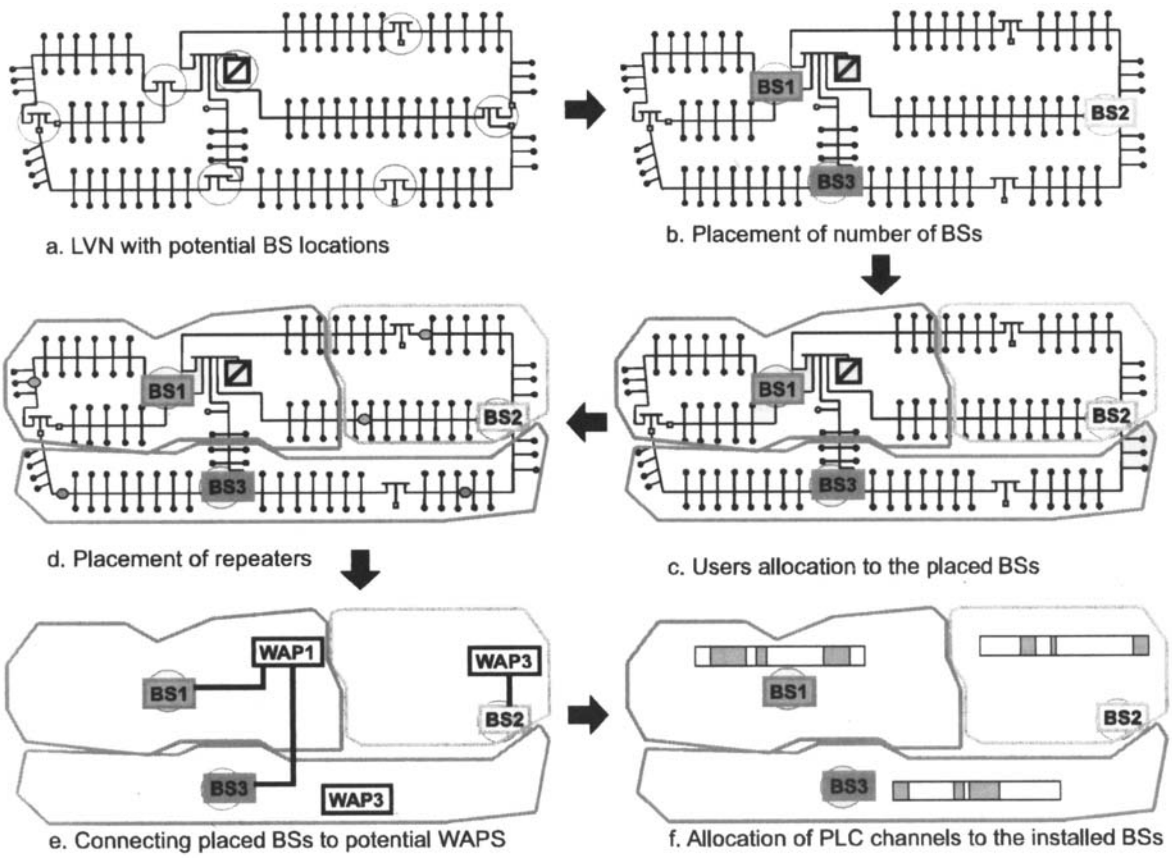


Figure 23: The different phases for network planning (Haidine, 2008)

The planning for MV DLC deployment is often based on the field measurements for each point of the planned deployment according to the utility needs or on the DLC PHY planning tools if a planning team has them. It is recommended to develop an interface between the mentioned tool and a utility GIS (geographic information system)/NIS (Network Information System) in order to export grid database into the DLC planning tool. The mentioned planning tool provides an estimation about the expected DLC signal attenuation, group delay and input impedance in each signal direction.

As in DLC system the IPv6 will be implemented, the integration in the mixed infrastructure (DSL, Hybrid Fiber-VDSL (HFD), LTE, WiMAX, UMTS, GPRS) should be seamless. Implementation of IPv6 also solves the problem of address resolution, which is present in IPv4. Due to the large address fields, the Network Address Translation (NAT) is not used anymore in IPv6.
Due to (Haidine, 2008), the following details must be provided to solve the task of PLC network planning:

- Low voltage network **(LVN) topography**
- The number of available **WAPs and their capacities**
- WAP-BS connections **cost matrix**
- Users **traffic demand**
- The **costs** of BSs and repeaters
- An **access control scheme** to the medium (this is derived from the MAC layer)

3.2.2. Installation

3.2.2.1. Use case and procedure of installation process

Use case installation:

This use case provides a description of the installation process of a DLC device and the requirements for the equipment needed to support the process. Most activities in the process are executed by personnel on-site. The activities are therefore required to complete swiftly in order to reduce the amount of time personnel spends waiting. It is assumed that the DLC device is a stand-alone device and not integrated with for example an electricity meter. Installation requirements for integrated devices can be found in (Open Meter, 2009).

The trigger for the installing/re-installing can be:

- New installation.
- The device needs to be replaced because it does not meet regulatory requirements anymore.
- The equipment needs to be replaced as a result of malfunctioning of the device.
- The equipment needs to be replaced at the end of the lifecycle of the equipment.

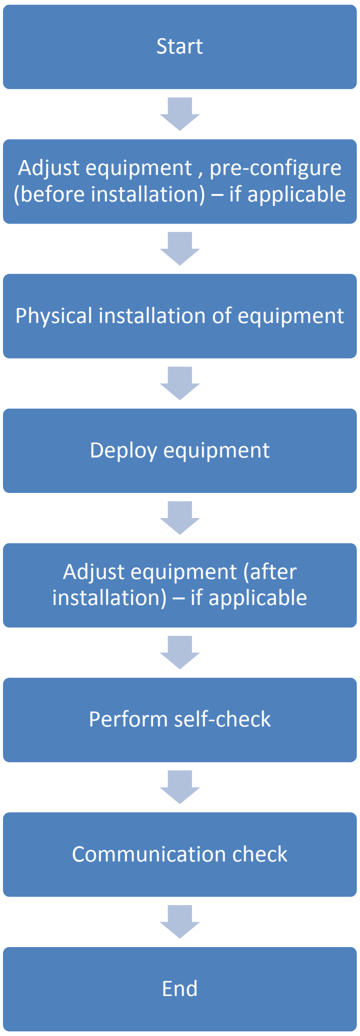


Figure 24: installation use case

Pre-condition: the equipment is in initial state as produced.
Post-condition: the equipment is in operation.

Derived requirements:

- The DLC Device Manufacturer shall include installation documentation that includes instructions for installation (e.g., placement), commissioning, and registration.
- The DLC equipment should be installed without the need for changing the existing customer installations (dimensions, connectors, and fixing of the equipment). The DLC communication components will comply with the current, country specific specifications in terms of dimensions, connectors and fixings at the existing customer/operator premises to allow their installation without the need for changes. In general the DLC communication components must comply with the current, country specific specifications in terms of installation of electrical equipment.
- Maximum automation of the roll-out process should be supported by technology and protocols. Once a DLC device is installed, the Network Management System should detect its presence and make it available to remote management. To maximize the automation of the implementation process the system should be independent of the technical information (cartographic information and client-network links) and flexible in the event of topology changes in the network.
- The DLC components should be designed and manufactured to minimize the cost of installation.

- In order to ease the roll-out process and minimize the inconvenience for end customers during the installation phase, the necessity of customer presence in the installation process should be reduced as much as possible.
- Roll-out speed should not be determined by the technology. The DLC components should be designed to make a scalable implementation possible without reducing the whole system performance allowing the adjustment of the roll-out to maximize the economical benefits of the system and taking into consideration aspects such as labour capabilities or national regulation requirements.
- All DLC devices must be properly identified by a label on the housing.
- The DLC device should provide functionality to set location information in the device after the device is physically installed. Grid Operator's could set location information in the device for maintenance reasons. The location information typically consists of zip code and house number or geographical co-ordinates for devices installed at the customer premises, or of the identifier of the primary or secondary substation.
- The DLC device shall provide functionality for adjustment of configuration parameters or operational parameters after the device is installed. The adjustment may be performed remotely or locally.
- The DLC device shall provide functionality to perform a self-check and retrieve the results remotely or locally. It is necessary to verify that the installation functions correctly before the installation is completed. Typically personnel that installed the equipment shall invoke a self-check as one of the last steps of the installation process.
- The DLC device shall provide functionality to perform a communications check. The communication check verifies that the device communicates correctly and, if not, reports the problems.
- The DLC device should indicate that the installation and activation of the device was successful or not. During installation it is important to have confirmation of a working connection/device.
- The DLC device shall provide functionality to reset its state.
- Special care has to be taken into account when uninstalling a DLC device. As each DLC end node can act as a repeater for other DLC devices and serve as an essential communication component for equipment that is not part of the installation served by the DLC device to be uninstalled.
- Uninstalling a DLC access point/bridge. Communication with other equipment than the equipment served by the device shall not be affected in anyway by the removal of the DLC access point/bridge.

3.2.2.2. Specific installation requirements

Specific installation requirements are typically regulated by National and Local authorities (e.g. VREG - Meetcode elektriciteit[2]). Further examples are given with the following typical applications.

Smart Meters / MUC:

Today's Smart meters concept is designed modular. At the costumer station there are located several meters (Gas, Water, Electricity, Heat) with different communication interfaces connected by a central communication unit, the "Multi Utility Communication - Controller MUC-C" (see also section 3.1.1.1). This unit reads out the data and pushes it to the measurement service provider in fixed intervals.

Because of this concept, the PLC chipset will be integrated as a common communication part in the MUC-C, therefore installation conditions can be derived from the MUC-C. Currently, the VDE-FNN defines the functional as well as the constructive requirements of the communication controller, which is documented in a draft "MUC-C Specification Version 1.0".

Data Concentrators:

[2] http://www.vreg.be/vreg/documenten/technische%20reglementen/TRDE30112004.pdf

A different situation is given with the installation of data concentrators in the net stations. Assuming that all functions necessary for communication are implemented in the central components by a compact design the installation conditions are resulting from the "Technische Anschlussbedingungen (TAB)". These define the arrangements for the supply of ancillary equipment, the safety standards, and the design features to net-stations, location of secondary technology and their spatial dimensions. Further requirements with respect to signal coupling are expected after selection of a coupling type and a definition of constructive characteristics which can be done after evaluation of the field tests in the project.

3.2.3. Operation

Due to the great effort required to transmit data via DLC, providing an oversized data rate to achieve a sufficient communication even with a poor utilisation, such as for Ethernet, is not feasible. Efficient usage is only possible if the characteristics of data volume, data streams and the corresponding delay requirements can be limited for transmission. Thus it will, for instance, be very difficult to efficiently combine voice transmission with the need for a constant data rate and only a minimal delay, a web browser, needing large amounts of data at high data rates but with loose time constraints, and a control application in facility management with a high number of independent small data packets within one system. It is then sometimes better to dispense with certain applications or serve them with a specially developed system in order to provide a well suited system for a broad scale of applications. To reach this the DLC system should be as transparent as possible for the applications (Rempli 1-2, 2003).

The definition of operational requirements depends on the one hand on the applications that shall be run over the communication system respectively the related services that have to be supported in this context and on the other hand on the operation scenarios. These are already described in detail in chapters 1.1.3 and 2. In the following section the main operational requirements are given with a focus on some core functions of the system which are listed first.

3.2.3.1. Considered Applications / Core Functions

The goal of the project is to design and implement a communication infrastructure not only for traditional power grid applications like distributed data acquisition (metering) and remote control operations, but also new applications like demand side management, control of DER, and others using the power grid as the communication medium. The users of the system like utility companies will benefit from the system by gaining more detailed information about how energy is consumed by the end-users. In addition, they will have more information about the status of the power grid and they will be equipped with means to remotely terminate supply of energy, if this is required (e.g. in pre-paid systems). Based on the availability of fine-grained energy consumption data at the end user's site, the energy flow can be better controlled and leakage can be detected more efficiently.

According to the latest CIGRE survey, there are 12 electrical services for automating the MV and LV Distribution Grid:

1. Tele-control
2. Tele-control (Fault detection)
3. Operational Telephony
4. Corporative application access
5. Video surveillance
6. Video supervision
7. Alarm Management (Temp., humidity, gas, flooding, etc.)
8. Tele-measurement. Product and Power quality
9. Protection Tele-measurement.
10. Operation/Supervision TELECOM Network

11. AMM and AMR
12. Load Management

AMR (Metering Service): Automated meter reading (AMR) implies the remote reading of the measurement registers of a meter without physical access to the meter. It can be implemented via a temporary RF (radio) link to the meter from a car passing by in the street while interrogating the meters, or as an always connected communication link (wireless or wired) to the meter.

Telecontrol (Remote Control and Monitoring Service): The control of operational equipment at a distance using the transmission of information by telecommunication techniques. NOTE – Telecontrol may comprise any combination of command, alarm, indication, metering, protection and tripping facilities, without any use of speech messages.

Video surveillance: A digital video surveillance system aims to give higher security to all range of public or private facilities, either by locally or remotely monitoring the video sequences captured in the areas covered by it. This purpose is obtained through the installation of video cameras, sensors, image processing units and network devices, which allow the capture, processing and transport of the surveillance data. Due to the limited network bandwidth the video surveillance mentioned in this project is restricted to surveillance of MV/LV sites and equipment. For the same reason the video capturing will be event triggered (alarm indication, door opening,…), the capturing/transmitted frame rate and video resolution will be limited, and video traffic optimization techniques will be used.

Operational Telephony: Operational telephony provides personnel at LV/MV sites a direct bidirectional audio connection to the network operation center. In the scope of this project it will be a VoIP connection over the DLC network.

Load management, DSM: the purpose of DSM programs is to modify the behaviour of electrical loads of different customer types (e.g. end-uses at domestic/residential, commercial, or industrial facilities) in order to optimise energy production costs, enhance energy utilisation or system reliability, or to match utilisation to environmental factors. When planned accordingly, they can also contribute to defer investment in new infrastructure by diminishing the peak capacity requirements of the system. Active Demand (AD), Demand Response (DR) or Demand Side Response (DSR) is a newer term describing the market-based approach to load management.

Most of these services are used for different applications. These services operate on the MV as well as LV levels of the Distribution Grid and they require transparent and flexible connection to the utility communications. Some of the services mentioned above belong to the group of the mission critical services requiring high availability of the provided utility communication.

These services and applications shall be separated logically to be administrated by the different groups of the utility operators.

3.2.3.2. Traffic flows

The following requirements can be listed with respect to traffic flows:

- A certain packet rate of packets transmitted only for routing and networking purposes is required and has to be taken into account.
- Support of push and pull (poll) operation (default: push)
    - Push
        - provision of connection-less unicast/multicast/broadcast lines
        - unicast lines include “end-to-end confirmation” in the link layer (and not “fire-and-forget”)

  - Pull: provision of connection-orientated unicast lines

- Support of broadcast messages without acknowledge (e.g. tariff info, FW update, time sync.)
- Handling of broadcast groups (i.e. multicast)
- If we analyze the application protocols for metering, automation, facility management or grid management we see a point to multi-point communication transferring mainly short messages (20-128 Byte). (Bumiller, 2010)
- In automation or grid management we mainly have master-slave structure, because these applications have a strictly hierarchical organization. (Bumiller, 2010)
- In facility management, client-server relations can be seen more often. A centralized client polls the server (data points) or the servers push the data periodically by their own. (Bumiller, 2010)
- In metering applications, there is a change from master-slave systems (pull-systems) towards client-server relations with a growing share of push operations. (Bumiller, 2010)
- A common point for all these systems is that almost all traffic flows between a single point and all other communication points. The throughput at this single point defines the overall system performance and therefore this point represents a bottleneck for communication. (Bumiller, 2010)
- Support of dynamic channel use for different services
- Some applications require cyclic requests with short cycle duration and low data amounts
- Peer-to-peer isolation is required for security reasons, unless node-to-node communication is a requirement.

3.2.3.3. Reliability / Redundancy

For the targeted applications of the DLC+VIT4IP system reliability is of great importance.

Yet, no matter how much redundancy is provided, a communication system can never guarantee 100% availability. Therefore, the design of an application also has to take the case into account that the communication might be temporarily out of service or in error states and provide respective measures how to deal with this, i.e. provide certain back up solutions, emergency behaviour or redundancy. Respective backup modes can be implemented both at remote or central side, depending on the application.

Against the background of these assumptions the basic requirements with respect to reliability and redundancy are given as follows:

- Repeater functionality with redundancy
- Dynamic adaptation of transmission in case of bad connectivity
- Unique assignment of addresses
- Redundancy [3] is required with respect to switching states of the grid
- Load balancing is required if redundancy is available.
- A node should be reachable via more than one concentrator (access point/bridge) as far as possible in order to offer redundancy and management of communication load!!!
- Monitoring of connections with respective connection qualities should be provided during operation.

[3] Redundancy does not necessarily mean - especially on the power line - that a second distinct communication path is available.

- High reliability against significant changes[4] in the communication channel. There is no straightforward way to simply inform the communication system management about topology changes that are about to occur. Rather, the communication system itself must be designed for robustness.
- Reliability and real-time properties of the network have to be maintained even during topology changes. → Maintenance of system availability is only possible with redundant communication links that are managed automatically, i.e. automatic routing. (Annotation: A communication system requiring a channel estimation phase (including a retransmission process) and link establishment after a change of topology will not fulfill the real-time requirements.) (Bumiller, 2010)
- Automatic handover procedure when the connection to the concentrator (similar to GSM cells) is lost.
- Automatic function of the self network management is most important.
- Full coverage for all network participants even over long distances. (Bumiller, 2010)
- On principle, provision of redundancy shall be foreseen on the following 3 levels where the application of these levels and respective measures depends on the requirements of the respective application: HW redundancy, SW redundancy and routing redundancy.
- In order to not affect the DLC communication functionalities whilst DLC nodes are under SW download, it is recommended to use Flash equipped with two memory banks.

3.2.3.4. Quality of Service (QoS)

QoS requirements are used to derive resource requirements for entities such as computation, communication, and storage. In the scope of this project the QoS requirements for the application level will induce the QoS requirements for the communication level.

Definition of QoS Parameters

The following QoS parameters will be considered:

- Classification of the application in terms of critical/non critical. An application may require a higher QoS not based upon its operating requirements, but based upon its importance in the overall system.
- Datarate of the data communications network: depending on the location in the network (MV,LV), the cardinality of the nodes (leaves) in the network, and the different applications running over the network and their BW needs, the datarate of the communication network can be a stringent constraint. As such the network must be properly dimensioned, partitioned and managed in order to avoid any kind of communication bottleneck.
- Latency:
  - One-way latency is the time from the source sending a packet to the destination receiving it.
  - Roundtrip latency is equal to the one-way latency from source to destination plus the one-way latency from the destination back to the source (thus without the time the destination

[4] Such a change may be introduced by distribution network management which balances the power consumption load on the power grid, especially on the medium-voltage level. Switching actions are initiated via various supervisory control and data acquisition (SCADA) systems (or even manually) using specific communication protocols that may not be modified. To give an example: If distribution network management switches a secondary transformer station from primary station A to primary station B, a request and response to and from the node may have to go via primary station A, the confirmation already via primary station B. (Bumiller, 2010)

system spends on processing the packet). Round-trip latency is more often quoted, because it can be measured from a single point. In IP networks 'ping' is often used to measure the roundtrip latency.

- Jitter: jitter or better said packet jitter or packet delay variation is a measure of the variability over time of the packet latency across a network. A network with constant latency has no variation or jitter.
- Type of traffic: the traffic can be classified as continuous, random or periodic. The traffic stream can be classified as constant(constant bite rate), variable (variable bit rate) or bursty.
- BER: (average) Bit Error Rate is defined as the ratio of errored bits to the total bits transmitted in some time interval. The bit error rate is significant for real time traffic like voice or video traffic. This type of traffic is mostly sent unassured via UDP/IP. Lost packets or faulty received packets are not retransmitted by the sender.
- PER: packet error rate
- Availability: is the amount of time a device is actually operating as the percentage of total time it should be operating.

Annotations to the parameters:

- BER,PER: While particularly for system simulation the BER is also a useful parameter, from the application point of view the PER is the actually relevant parameter. This is due to the fact that an erroneous packet is thrown away, no matter how many bit errors it contains. However, a PER is difficult to specify, as it depends amongst others on DLC packet size and number of MAC layer retransmissions, which in turn has a direct effect on latency respectively packet jitter. Hence, at the current stage the specification of a PER is renounced. Instead, the BER is specified which can serve as an indicator for admissible packet error rates and can be used as an input for simulation for optimisation of packet sizes and determination of PERs.

Overview / QoS Parameters for considered services

	bandwidth (kbit/s)	traffic type	Ma. Latency (s)	Max Jitter (ms)	BER	Max time of network recovery	Functional unit	Concentration	Main use
AMR	5,3 (1)	Periodic	0,5	NA	NA	1...2 hrs	per concentrator	300	LV
SCADA	1,8-9,6	Random	0,5	NA	1E-06 - 1E-14 (2)	1s	per concentrator	20	MV
Operational Telephony	8	Random	0,5	30	1E-03	15s	per call		MV
Video surveillance	15-128	Random	1	NA	1E-04	NA	per camera		MV
Load Management , DSM,DSI		Periodic	1	NA	NA	1s			MV,LV
Software download / upgrade firmware	32	Random	NA	NA	NA	NA	per concentrator	300	MV,LV
street lighting dimming & traffic control & maintenance	0,025	Random	300	NA		NA	group (32)	4	MV,LV

(1) 15 minutes interval

(2) Residual error rate according IEC 60870

Table 9: Overview of QoS Parameters for considered services

Based upon data and references listed in appendix section 6.3 the following QoS parameter requirements can be derived.

3.2.3.5. AMR/AMM

AMR/AMM is a non time critical application where the meters in the LV network have to be read out periodically. A subsystem on one transformer station contains on average 150…200 (max. 300) metering points (smart meters[5]) . When all meters have to be read out every 15 minutes, 96 data packages per day and per meter have to collected . At a net data volume[6] per meter of 2 kByte every 15 min this results in a 18 bit/s per meter. At about 300 meters per transformer station, thus 600 kByte every 15 min this results in 5333 bit/s per transformer station. As meter data is collected for back office treatment like billing latency and variation of delay (jitter) are not relevant. AMM on the other hand requires a maximum time of 30 seconds for response on a request command for control signals. The average net data volume for control signals[7] is about: 500 Bytes (for example: set MUC-C RTC, remote switching in the customer station, ...).

3.2.3.6. SCADA

SCADA is a grid critical application to control the automated devices and monitor the electrical network. Most of the automated devices are located in the MV network. Assuming about 20 devices to be controlled per data concentrator at 200 bytes per message at 200 messages (request and response) an hour results in about 1800 bits/s (based upon real live trace by utility). SIGRE based bandwidth for SCADA applications ranges from 9.6 till 64 kbit/s (appendix section 6.4.).

As controlling and monitor is critical this reflects in the latency and error rate values. According to [IEC 60870] the requirement for residual error rate is:

- 10E-6 for cyclic updating systems, telemetering,
- 10E-10 for event initiated transmission, teleindication,telecounting.
- 10E-14 for critical information transmission,telecommands.

Note that obviously these errors must be detected and corrected in higher level protocols.

The maximum latency ranges from 0.5 second for tele-control, 1 to 5 seconds for fault detection tele-control to 30 seconds for (temperature, gas, flood, humidity) alarm management . Jitter is not relevant.

3.2.3.7. Video surveillance

The requirements for video surveillance depends on the video resolution, the number of captured and sent frames, the codec and if the video capturing is event based or continuous. For instance in common intermediate format (CIF; 352 x 288) at 1 frame per second requires about 15 kbps upstream, at 4 frames per second 36 kbps and at 10 frames per second 128 kbps.

Latency should be less than 1 second and a maximum bit error should not be more than 10E-4.

[5] Metering points might be also MUCs (Multi Utility Communication) with several meters (eletricity, water, gas, heating). But as the electricity meter plays the dominant role with respect to data throughput, the current consideration can be reduced to the electricity meters, i.e. a metering point is assumed to be a smart (electricity) meter here.

[6] Data string AMR: date | time | reading value | ID | … | signature

[7] Estimation based on SML protocol description

3.2.3.8. Operational telephony

The throughput requirements for telephony depend on the codec used, but in general 8000 bits/s (codec G729a) per call is sufficient. The VOIP traffic type can be constant bit rate or variable bit rate depending on the activated voice features and codecs. For instance when the voice activity detection feature is activated the VoIP traffic is characterized by talking and silence periods. Latency should be less than 0.5 second, jitter less than 30 ms and the maximum bit error rate should not be more than 10E-3.

3.2.3.9. Software download / firmware upgrade

Software download is not time critical, can be done in background and even be interrupted and continued later on. Assuming 100 kByte up to 10 MegaByte per software load over 24 hours results in 9 till 900 bits per second throughput per device. The devices do not have to be updated at the same time. Most devices can store two software loads: one active and one inactive. In case of software upgrade the inactive one will be replaced by the new version. A switch over, where the inactive program becomes the active one, and vice versa, can be simultaneously triggered for all devices if necessary. Latency and jitter are not relevant.

3.2.3.10. Street lighting dimming, maintenance and traffic control

A telemanagement system for street lighting enables the lighting system to automatically react to external parameters like weather circumstances, remaining daylight level, accidents or traffic density. The data communication on the street level can be based on the Power Line Communications protocol. The system can not only be used to control the street lights, but also to monitor the age and condition of every street lamp. Telemanagement of street lighting with bidirectional communication can be used for monitoring, control, metering and diagnostic applications that save energy, reduce maintenance costs and improve system reliability.

This application is not time critical. A data rate 25 bits per second is necessary to control a group of 32 street lights. Latency for control commands can be up to 300 seconds. Jitter is not relevant.

3.2.3.11. Real-Time Requirements (complementary)

- Switching operations require fast reactions
- The required reconfiguration time or time of network recovery, i.e. the maximum time after restart of the power grid where the link layer of the PLC network has to be completely operable again and configured,
  - for smart metering applications: is at maximum 1 to 2 hours
  - for smart grid applications: will have to be clearly shorter (several seconds)
- Smart grid applications involve the integration of decentral energy generation plants (wind, CHP, photovoltaic) which require reaction (or even response) times in the range of seconds (those plants require fast control operation and hence fast data acquisition and data processing)
- For smart grid applications real-time requirements also have to be guaranteed during switching processes in the network without knowledge about these switching actions at the DLC devices.

3.2.3.12. Consequences for the system

Basic consequences that result from the QoS requirements are as follows:

- Application needs possibility to define QoS and DLC has to fulfill

- Quality of Service (QoS) management for different types of data requires differentiation of data classes or Communication Access Classes[8], e.g.:
    - Real Time@Data (high throughput, low reliability,…)
    - Real Time@Latency (low throughput, high reliability)
    - Telemetry (scheduled throughput, medium reliability,…)
    - Background (low throughput, high reliability,…)
- The QoS management has to work in a single packet-oriented way (as opposed to applications like video or voice-over-IP streaming with resource reservation)!!!
- Handling of priorities
    - "Task processing with priorities" has to allow selective processing of single tasks faster than others from the viewpoint of the control center, e.g. different priorities for read-out and switching commands
    - Support fast transmission of urgent events/alarms from communication nodes
    - Priorisation of data packets is also required for push mode with end-to-end-confirmation in the link layer
    - Support urgent commands from control center to single communication nodes.
- Monitoring of transmission quality has to be supported.

3.2.4. System management / Maintenance

The electrical grid in Europe is divided into several regions, each of these regions is a synchronisation domain. To cope with the already existing infrastructure the following scheme Figure 25 (left side) was derived. The relations and cardinalities between the different objects in the electrical grid can be seen in Figure 25 on the right side.

[8] Notes : Access classes are proposed as a generic means of classifying communication access QoS. These could then be specified in more detail for the specific communication service. Once we have mapped these scenarios with some high level classification of the service we can then elaborate technical requirements in 3.3. The detail scenario defined later will cover more elaborate scale of the outlined scenarios

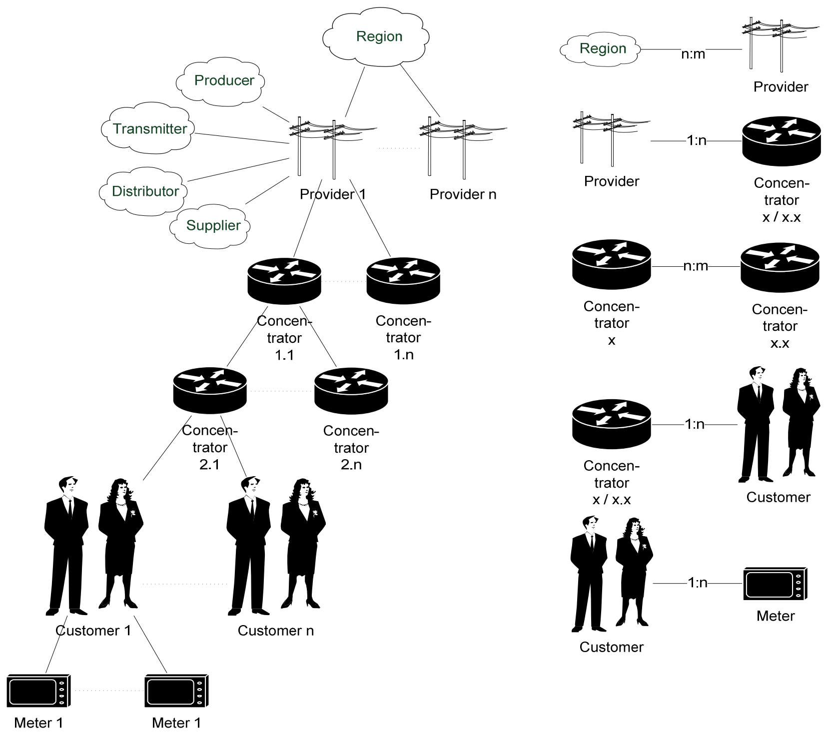


Figure 25: European electrical grid and relations between the objects of the electrical grid

3.2.4.1. DLC NMS - Network Management System

3.2.4.2. Configuration management

This feature performs registration, deletion, and settings change of Node, REP (repeater), and Modem/CPE (Customer Premise Equipment) information. At the time of registration, DLC-specific information of the entry such as MAC address, frequency, and end user information is stored into a database. Once entered, the DLC equipment becomes included in the topology view and tree view displayed on the screen for monitoring. In addition, the configuration file of the registered equipment can be edited from the DLC NMS server.

Features:

3.2.4.3. Add/Remove DLC network equipment .

Registers/deletes a piece of DLC equipment to/from the server.

3.2.4.4. Link with DHCP- management the mapping between MAC and IP addresses.

Automatic IP address configuration at nodes-is required to keep the overhead for installation low. To support seamless IP assignment throughout the complete utility, the DLC+VIT4IP system should use standardized protocols. Today, company network often includes a DHCP-based assignment concept.

It is necessary for each DLC+VIT4IP equipment to have its own IP address for remote management. Since a method of assigning a fixed IP address at the time of installation involves a complicated procedure, DLC equipment shall be configured in a way that its IP address will be dynamically assigned.. However, generally speaking, equipment whose IP address has been dynamically assigned cannot be monitored. Therefore, NMS shall be equipped with a functionality that is implemented in such as way that a fixed IP address can be assigned automatically in a predictable way.

IPv6 has it's own stateless address autoconfiguration mechanism that fulfills the above requirements, yet two special cases have to be considered:

1. The IPv6 assignment is not working if the MAC addresses are smaller than 64 bits, which is the case for most PLC systems and the two systems used in DLC+VIT4IP in particular
2. The DLC+VIT4IP system should be able to support IPv4 address as compatibility measures for existing (field) equipment.

Possible candidates to address these two requirements are the use of DHCPv6 and DHCPv4, respectively. Possible solutions are a direct implementation of the DHCP protocol or special configuration of these servers that allow a mapping of the automatic DLC+VIT4IP IP assignment with the company wide DHCP management. E.g. by installing a script with the DHCPv4 server the IP address of equipment using a dummay MAC address as a key.

Both DHCPv4 and DHCPv6 will be supported to main compatibility with existing infrastructure.

3.2.4.5. Link with an authentication service - authentication of DLC equipment

DLC equipment should automatically detect any newly connected equipment and control whether to allow access from this equipment to the network with the help of the authentication mechanism which can be provided by an authentication server. Further, by setting up a profile, the PnP (plug and play) of DLC equipment is enabled.

The setting up of an authentication server is a very complicated task. In order to relieve the operator’s task to set up this server in the case of DLC NMS, a functionality shall be provided for performing automatic registration (e.g. by a script installed on the authentication server).

The security system should link to an authentication server (e.g. Radius) andregisters authentication information for PLC equipment.

3.2.4.6. Display current status of DLC equipment using SNMP protocol

Collects information on the current status of PLC equipment using the SNMP protocol and displays it.

3.2.4.7. Get/Set remotely the communication parameters of DLC equipment using SNMP protocol.

Remotely references and sets communication parameters of DLC equipment using the SNMP protocol.

3.2.4.8. Direct edition of the configuration file and its registration with the server.

Allows the direct editing of a configuration file and registers the file with the server.

3.2.4.9. Redundancy Management

Allows the management of a Primary and Secondary DLC equipment in order to ensure DLC system redundancy.

3.2.4.10. Frequency planning and channels configuration

Allows the management of the frequency and channels resources according to the DLC network planning and RF characteristics of the Distribution Grid under DLC deployment.

3.2.4.11. Automatic Grid Impedance matching

Allows the required QoS management according to the static and dynamic physical characteristics of the Distribution Grid under DLC deployment.

3.2.4.12. Fault Management

This feature monitors possible failures by periodically polling DLC equipment. In order not to interfere with operational communication bands, polling intervals can be set in units of seconds. The feature also has the capabilities to receive SNMP traps and display their information in the form of fault history, as well as to indicate any fault condition in topology view. Detected events are logged so that events of interest will be able to be searched for and displayed.

Features:

3.2.4.13. Periodical polling DLC equipment and current status display

Periodically checks the current statuses of DLC equipment and displays the statuses.

3.2.4.14. Receive and display Alarms/SNMP traps from DLC equipment and their classification according to the predefined priorities, i.e Critical, Major and Minor

Receives and displays SNMP traps from PLC equipment.

3.2.4.15. Fault history – logs of DLC network events including search engine for a fault of interest

Logs occurrences and recoveries of faults and allows the user to search for a fault of interest that has occurred for display.

3.2.4.16. Performance Management

This feature can collect DLC network-specific physical characteristics such as DLC's physical speed,transmission/reception levels (TXGain/RxGain), SNR (Signal to Noise Ratio) and Data Rate/BPC (Bit Per Carrier), as well as data communications traffic, and render such collected data into graphs. The figure attached below shows an example of such a graph being displayed.

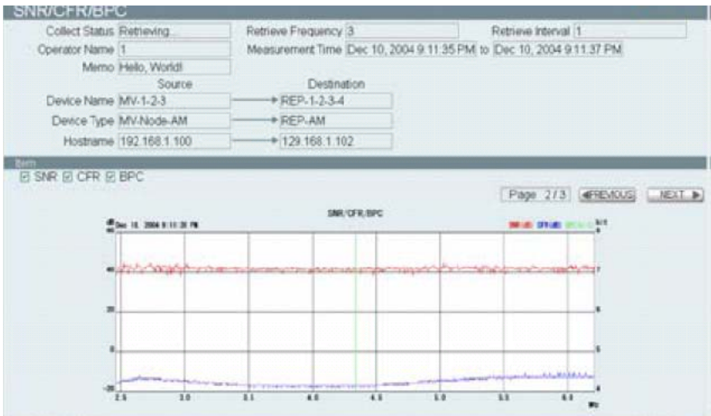


Figure 26: Example of a performance management feature

Features:

Periodical data collection about the communication performance of DLC network including network throughput as well as SNR and Grid Wave Impedance.

Displays the collected data graphically.

Traffic statistics including raw and net data rates and their graphical display.

Periodically collects statistical data such as octets transmitted/received for display in graph form.

3.2.4.17. Equipment (SW) Management

This feature displays card information and firmware version information. The downloading of firmware or a configuration file can be directed from DLC NMS. In addition, direct telnet access could be possible to DLC equipment.

Features:

Info about current HW and SW versions of the DLC sophisticated devices.
Displays versions of card and firmware in the DLC sophisticated devices.

Remote and local single SW upgrade download.
Remotely upgrades firmware to a single DLC sophisticated device.

Remote group SW upgrade download.
Remotely upgrades firmware to a group of the DLC sophisticated devices.

Configuration file upload and download. Single and group loading.
Uploads/downloads a DLC equipment configuration file to/from a file server.

Direct access to a piece of DLC equipment.

3.2.4.18. System functionalities

Forms of connection of DLC equipment are of the open ring type, the radial type, the tree type, and so on, where MV nodes, REPs, and Modem/CPE are hierarchically connected with each layer of level formed by respective types of equipment. If we try to display these connection relationships graphically at a time (or in a single view), the relationships between upper-level equipment and lower-level equipment are difficult to interpret, and thus operation on the screen becomes difficult to perform as well. To solve this problem, it is required to present PLC equipment connection relationships in a combination of a tree view and a topology view. The figure attached below shows an example screen shot displaying the tree view and the topology view.

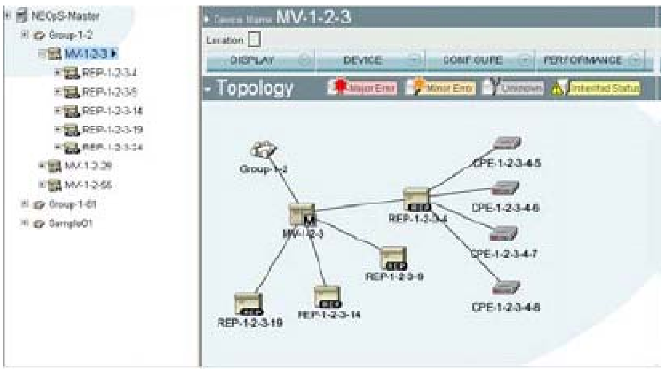


Figure 27: Example screen shot displaying the tree view and the topology view

The tree view can offer the user ease of operation and represent the hierarchical relationships among individual pieces of equipment in an intuitively obvious manner. The topology view can represent the topology of DLC equipment precisely.

Features:

Tree view of DLC equipment connection relationship.
Displays PLC equipment connection relationships in a tree view.

Graphical DLC network configuration display and current statuses of DLC equipment. DLC Network Topology view.
Displays network configuration graphically to show the current statuses of DLC equipment in a dynamic manner.

DLC network topology drawing.
Allows the user to create a topology views as he/she likes.

Operator management and restrict authorization.

Manages login and password information of operators and sets restrictions on the kinds of operations individual operators are authorized to perform.

3.2.4.19. HMI

Screen display and operator management. The screen consists of a tree view area and individual

information display area. The individual information display area shows the topology view, properties,

graph view, fault history and the like for each piece of DLC equipment. Access to DLC NMS is managed by the operator management function, so that unauthorized manipulations can be blocked. General users can only reference the states. To perform registration and/or make settings on DLC equipment, the operator must have an administrator privilege. Using a PC with an Internet browser installed, an operator can monitor and operate from anywhere on the window that the DLC NMS server provides.

3.2.5. Decommissioning

For requirements with respect to decommissioning the relevant standards can be referenced which are listed in this section.

3.2.5.1. IEC standards (limited)

The standards listed below are those applied to electricity meters, although the DLC component is often only a part of it they can serve as guidance.

Reference	Title	TC	Notes
IEC 62052-11	Electricity metering equipment (AC) – General requirements, tests and test conditions – Part 11: Metering equipment	TC 13	
IEC 62053-11: 2003	Electricity metering equipment (a.c.) –Particular requirements – Part 11: Electromechanical meters for active energy (classes 0,5, 1 and 2)	TC13	U< 600vac In-and outdoor meters
IEC 62053-21: 2003	Electricity metering equipment (a.c.) –Particular requirements – Part 21: Static meters for active energy (classes 1 and 2)	TC13	U< 600vac In-and outdoor meters
IEC 62053-22: 2003	Electricity metering equipment (a.c.) –Particular requirements – Part 22: Static meters for active energy (classes 0,2 S and 0,5 S)	TC13	U< 600vac In-and outdoor meters
IEC 62053-23: 2003	Electricity metering equipment (a.c.) – Particular requirements – Part 23: Static meters for reactive energy (classes 2 and 3)	TC13	U< 600vac In-and outdoor meters
IEC 62056-21: 2002	Electricity metering – Data exchange for meter reading, tariff and load control – Part 21: Direct local data exchange	TC13	Via hand-held unit
IEC 62056-31: 2002	Electricity metering – Data exchange for meter reading, tariff and load control	TC13	

Reference	Title	TC	Notes
	Part 31: Use of local area networks on twisted pair with carrier signalling		
IEC 62058-11: 2008	Electricity metering equipment (AC) - Acceptance inspection - Part 11: General acceptance inspection methods	TC13	
IEC 62058-31: 2008	Electricity metering equipment (AC) - Acceptance inspection - Part 31: Particular requirements for static meters for active energy (classes 0,2 S, 0,5 S, 1 and 2)	TC13	
IEC 60730 - series	Safety standards on automatic controls for household use	TC 72	
IEC 60529	Degrees of protection provided by enclosures (IP Code)	TC 70	

Table 10: IEC standards to be considered for decommissioning

Annotations:

- The IEC standards are adopted by CENELEC (EN-standards).
- IEC 62053-x supersede IEC 61036-x.

3.2.5.2. EN standards (limited)

Reference	Title	TC	Notes
EN 50470-1	Electricity metering equipment (a.c.) -- Part 1: General requirements, tests and test conditions - Metering equipment (class indexes A, B and C)	TC 13	
EN 50470-3	Electricity metering equipment (a.c.) -- Part 3: Particular requirements - Static meters for active energy (class indexes A, B and C)	TC 13	
EN 50470	General safety		
EN 50470-1	Relative humidity (%RV)		Refers to IEC 62052-11
EN 50470-1	Ingress protection (IPxy)		Refers to IEC 60529
EN 50470-1	Solar irradiation / vibrations…		

Table 11: EN standards to be considered for decommissioning

3.2.6. Economics

The generic economic DLC requirements are summarized in the table hereafter, an overview of all economic parameters related to DLC application are included in Appendix 6.5.4.

Parameter	Max.
Specific economic DLC parameters (added in this study)	
Cost of DLC component for product integration (e.g. add on for AMR) [€]	50
Cost of DLC device in stand alone app. (e.g. access point) [€]	200
Cost of MV coupling device [€]	600
DLC modem component failure rate at minimum life time of 10 years	3%
DLC modem component premature failure rate before 1 years	0.30%
Average DLC modem component power energy consumption [Watt]	1.5
Set up time for DLC system [months]	12

Table 12: Summary of generic economic DLC requirements

3.3. Technical Requirements

3.3.1. EMC (devolo)

This section addresses EMC requirements based on the European regulatory framework. DLC-VIT4IP aims to deploy the frequency spectrum from 3 kHz up to 500 kHz. The European regulatory framework that is based on European Harmonized Standards by CENELEC distinguishes between 3kHz – 148,5 kHz and above 150 kHz concerning emission and immunity requirements.

3.3.1.1. Emission

PLC transmit mode

3 kHz - 148,5 kHz	150 kHz - 500 kHz	Only for information: 1,705 MHz – 30 MHz
EN50065-1	No reference	- No European Harmonized Standard - References for CE declaration o CISPR I CD 89 o CISPR I CD 257 o CISPR I PT PLT INF

Table 13: EMC requirements based on European regulatory framework – emission in PLC tranmit mode

The discussion on emission limits within the range of 150 kHz- 500 kHz has not really started yet in CENELEC, but devolo and iAd are doing their best to establish a standardization project on this issue. In the following, potential approaches are outlined:

a) Extending the lower frequency range up to 500 kHz: For class 122 products (products for general use) the limit is 122 dBµV for one-phase coupling and 116 dBµV for three-phase coupling measured at 200 Hz with a peak detektor.

b) Using the current status of inhouse BPL discussion (CISPR I PT PLT INF) for 150 kHz – 500 kHz: 105 dBµV (PK) measured in 9 kHz RBW. This requires in addition the <u>capability to notch and</u>

power management. The access BPL discussions are in a preliminary state, but there seems to be a broad consensus for increasing the limit by 10 dB.

Case a) and b) are simplified in their description. For a detailed specification, please refer to the references.

For illustration of the limit given in b): 95 dBμV (AV) (measured in 9 kHz RBW) is approximately equivalent to a power spectral density during the transmit bursts of – 55 dBm/Hz (measured on 100 Ohm).

The approach b) appears to have a higher probability in acceptance in the planned standardization project.

Idle mode without PLC transmission

3 kHz - 148,5 kHz	Above 150 kHz
EN50065-1	EN55022 Mains Port Limits

Table 14: EMC requirements based on European regulatory framework – emission in idle mode without PLC tranmission

3.3.1.2. Immunity

3 kHz - 95 kHz	95 kHz – 148,5 kHz	150 kHz - 500 kHz	Only for information: 1,6 MHz – 30 MHz
EN50065-2-3	EN50065-2-1 (domestic) EN50065-2-2 (industry)	EN55024	EN50412-2-1

Table 15: EMC requirements based on European regulatory framework – immunity

Remark: It needs to be considered in WP5, standardization, whether it makes sense to extend EN50412-2-1 to the frequency range 150 kHz – 500 kHz.

3.3.2. Powerline / Coupling

3.3.2.1. Coupling methods

General

A power line based communication system includes power-line termination modules (Access Points), a plurality of power-line gateways (Bridges), and a plurality of power-line nodes. AC coupling modules couple power-line components to powerlines in order to transmit signals between power-line nodes, Bridges and Access Points.

For using distribution systems as communications paths, signal coupling units with which to inject and extract DLC signals on those lines are necessary, with a choice of Capacitive Coupling Unit (CCU) and Inductive Coupling Unit (ICU) options.

In an access-type DLC system, medium- and low-voltage power distribution systems are used as part of a communications network. For radio frequency DLC using such distribution systems as communications paths, signal coupling and conditioning equipment are important items of hardware. However, conditioning is not a necessary prerequisite for powerline communication. The former equipment connects communications signals of a DLC modem to a distribution line, while the latter tries to improve the communications characteristics of such distribution lines. There are bypass tools and blocking filters for conditioning tool. The function of bypass tools is to bypass communications signals around power distribution equipment, a major source of signal attenuation. The function of blocking filters is to prevent the signals from being conveyed to unnecessary power distribution systems. Signal coupling

and conditioning equipment are key device for DLC business. It is necessary for us to develop considering the equipment installation and performance.

An ICU (Inductive Coupling Unit) is a piece of equipment to place communication signals in the 9 KHz- to – 500 KHz range onto a distribution line and a key device in the DLC system. A current of several hundred amperes is being applied to a medium-voltage distribution line at a voltage of 6.6 to 35 kV. Since the ICU is capable of achieving signal coupling with the distribution line without contact required, it is characterized by high reliability and ease of installation on existing distribution lines.

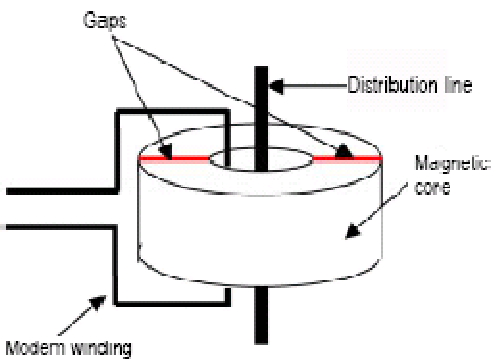


Figure 28: principle of an inductive coupling unit (ICU)

Structurally, it consists of a magnetic core with gaps plus a distribution line and modem output coil, both of which are wound around the latter core. Using the mutual inductance between the distribution and modem output lines, radio-frequency signals are coupled to the distribution line. The ratio of the magnetic core's mutual inductance to the self-inductance is known as the core's coupling coefficient, k. The greater the coupling coefficient, the better the coupling efficiency becomes. The gaps provided are to prevent the magnetic core from being saturated by the power current traversing the distribution line. The larger the length of the gaps, the less the effect of the magnetic saturation, but since the core's coupling coefficient k also becomes smaller, the ICU's coupling efficiency is reduced. To cope with this, the manufacturers have successfully optimized the core geometries using magnetic analysis. The coupling efficiency of the ICU varies according to factors such as the shape and magnetic characteristics of the magnetic core, the length of the gaps, and the characteristic impedance of the distribution line. This means that we start requiring ICUs that are matched to the characteristics of the distribution lines upon which they are to be installed. Consequently, the DLC integrators have been implementing ICU design through the use of magnetic field and circuit analyses.

Figure 29 shows a capacitive coupling device, represented by means of three functional blocks, which is used for linking the signal generator to the MV DLC channel. An impedance adapter device, shown below by the non-ideal transformer with transmission matrix $[T]^T_T$ and turns ratio N1/N2 is used to match the complex impedance of the MV line and the output impedance Z_S of the signal generator. Moreover, the high-pass filtering behavior of the coupling circuit, formed by the drain coil L_T and the coupling capacitor C_T , is modeled as a cascade of the transmission matrices $[T]^T_L$ and $[T]^T_C$. When the signal wavelength is significantly longer than the conductor length, a coaxial structure such as a MV power cable can be modeled as a two-conductor parallel transmission line.

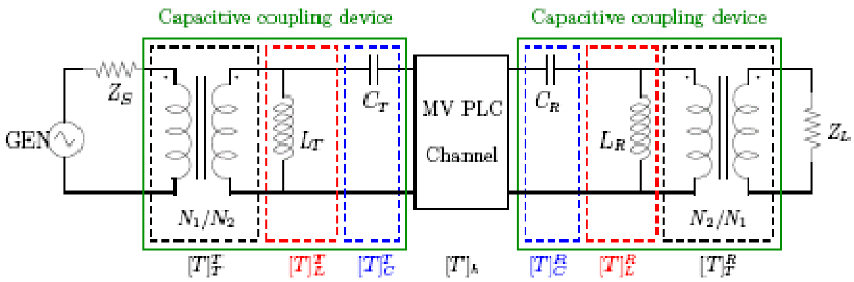


Figure 29: Network model of a capacitive coupling device

The installation of a signal-coupling unit may involve high-voltage work for overhead power line. For coupling units directly exposed to live parts therefore, effective insulation is important.

The coupling device has to provide the basic functionality of a high-pass filter which lets PLC signals pass but rejects the power system frequency such that it protects the communication equipment from the power system voltage, its harmonics and transient voltages caused by switching operations.

The realisation of the coupling is important for the system performance as this is one of the few ways to change the overall channel conditions to the better.

Where to couple in?

Communication nodes:

For distributing messages in the low-voltage segment sometimes only one phase is available at the location of a communication node and this phase cannot be determined. Therefore, principally it is is enough for a node to receive or transmit on only one of the three phases.

Repeater Nodes

Nodes in the low voltage segment with the special purpose to work as repeaters (socalled repeater nodes) are supposed to transmit and receive on all three phases.

Access points / bridges:

Those units which provide the access in the low voltage segment have to use all three phases for coupling (in/out) of the communication signals.

Within the medium voltage segment DLC communication might be performed on one phase only. As the crosstalk between these phases is very high the other phases cannot be used for independent communication.

How to couple in (capacitive / inductive)?

It is not possible to develop new coupling units within the DLC+VIT4IP project, because the mere costs for qualification of the devices are already much too high, which means that existing coupling units have to be used. Therefore, experiences of the project partners with respective units applied in existing systems have to be exploited.

Medium-voltage coupling

There are overhead and underground lines used for the MV Distribution Grid construction.

Different MV cable types are used for the underground lines.

Frequently, MV Distribution Grid is a mix of the overhead and underground lines.

All mentioned above requires the different techniques of DLC coupling in order to deploy DLC systems over MV Distribution Grid.

For coupling on medium-voltage lines two concepts exist, capacitive coupling and inductive coupling. With capacitive coupling units a voltage is driven between line and earth and at the receiver the voltage between line and earth is measured. Inductive coupling units, in contrast, induce a current, which is measured at the receiver.

Capacitive Coupling

The capacitive coupling units exist for outdoor and indoor installation. The supported voltages are e.g. 6 kV, 12 kV and 24 kV. For installation it is necessary to shut down the network.

A low impedance connection of the coupling unit to the shield of the used conductor and to earth is required.

Some example values from ERDF-spec (5.15.1) for a medium voltage capacitive coupling unit:

Parameter	Measurement conditions	Value
	Medium voltage circuit parameters	
Primary test voltage U_N	Voltage between the device input and grounding output	$24/\sqrt{3}$ kV_{RMS}
Test short-term alternating voltage U_{TH}	Voltage between the device input and grounding output during 1min.	50 kV rms
Maximum short-term working voltage. U_{MAX}	High Voltage during 9 Hours	26 kV_{RMS} 9 hours
Test lightning impulse voltage U_L	Impulse with duration of 1,2/50 us between the device input and the grounding output	125 kV
Partial discharge level		≤ 20 pC
Ambient temperature during operation		-40°-- +65°
Coupling capacitor capacity Cc	-40°C < Ta < +70°C	1.5 -13 nF
Fuse operate time max	at I ≥ 30A at I ≥ 45A	t ≤ 100 ms t ≤ 10 ms
	Low voltage circuit parameters	
Nominal line side impedance R_{LINE}		75Ω ≤ R ≤ 170Ω
Nominal equipment side impedance R_{LOAD}		75 Ω
Maximum operating attenuation in receive and transmit direction at R_{LOAD} = 75 Ω, R_{LINE} = 170 Ω	35 kHz ≤ f ≤ 170 kHz	3 dB

Table 16: example values from ERDF-spec (5.15.1) for a MV capacitive coupling unit

Note: Low voltage circuit refers to communication unit side and medium voltage circuit refers to the grid side of the coupling unit.

Inductive Coupling

If inductive the coupling should be only via core of the cable if possible (Bumiller, 2004):

- Coupling into the shield should be avoided as in this case the transmission depends too much on the respective realisation of the shielding and in some cases the signal will not reach the targeted receiver. Besides, in the shield there are also the compensating currents for electromagnetic disturbances which represent interferences at the decoupling location.
- Coupling into both line (core) and shield should be avoided as well because in this case the main part of the induced signal will often go into the shield as it offers an electric circuit with a lower impedance than the core line and then the disadvantages of pure coupling into the shield apply as mentioned before.
- Therefore the coupling only into the line is the preferred method for inductive coupling.

Low-voltage coupling

The LV underground and overhead lines being unshielded infrastructure require phase coupling.

Coupling on low-voltage lines is usually capacitive (as an example see datasheets of powerline chips).

3.3.2.2. Protection

The coupling units are supposed to provide protection for the communication device as far as possible (see section 3.3.2.1).

LV networks:

→ See (CEN, 2001), (CEN, 2003)

→ Safety requirements according to EN 50178

MV networks:

Case 1: Capacitive Coupling:

→ Standard IEC 60358 applies to coupling capacitors and capacitors dividers

→ Standard IEC 60481 applies to coupling devices for Power Line Carrier systems

Case 2: Inductive Coupling:

→ No harmonized standard available.

For further information IEEE P 1675^{TM}/D6 (Standard for Broadband over Powerline Hardware) can be referenced, which is currently only at draft state.

3.3.2.3. Impedance

Requirements for frequency range 9 … 148,5 kHz (CENELEC EN 50065-7)

For devices with operating range between 9 kHz and 95 kHz:

- Only restriction for send mode for the range 95...148,5 kHz: > 3 Ohm

For devices with operating range between 95 kHz and 148,5 kHz:

- Restriction for send mode for the range 3...9 kHz: > 10 Ohm
- Restriction for send mode for the range 9...95 kHz: > 5 Ohm

For devices with operating range between 148,5 kHz and 500 kHz:

- No specifications in this standard.

Requirements for frequency range 148,5 … 500 kHz (according to EN 55022 and CISPR 16-1)

For this frequency range no detailed requirements for impedances of the communication devices are given in standards. Only knowledge on the mains impedance is available.

For the compliance tests the normative EN 55022 uses an artificial mains network conforming CISPR 16-1 with a 50Ω//(50µH+5Ω) Network.

EN 55022 is related to 'Information technology equipment — Radio disturbance characteristics — Limits and methods of measurement'.

CISPR 16-1-2 is related to 'Specification for radio disturbance and immunity measuring apparatus and methods - Part 1-2: Radio disturbance and immunity measuring apparatus - Ancillary equipment - Conducted disturbances'.

The CISPR 16 '50Ω//(50µH+5Ω) ' network is as in figure below with R1 = 5Ω and R2 = 50Ω, wherein R2 is mostly the input impedance of the measurement receiver. The artificial mains network for testing is also often called Line Impedance Stabilisation Network (LISN).

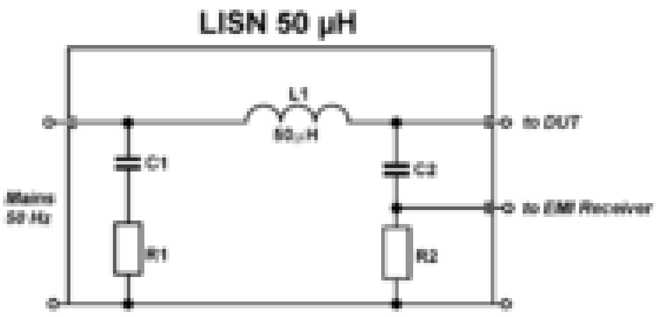


Table 17: Artificial mains network conforming CISPR 16-1

Mains impedance in real conditions (100-500 kHz)

For the compliance tests artificial mains networks conforming CISPR 16-1 are used. Measurements on real networks have shown that this artificial network do not truly represent practical network impedance. A power line has very variable impedance depending of several factors as for example its configuration (star or delta) the number of entities linked. An extensive data on this subject has been published by Malack and Engstrom of IBM (Electromagnetic Compatibility Laboratory)[9], who measured the RF impedance of 86 commercial AC power distribution systems in six European countries as illustrated in the figure below:

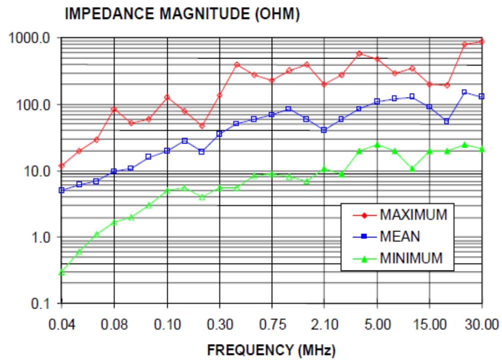


Figure 30: RF impedances in 86 commercial AC power distribution systems

3.3.3. Network conditioning

3.3.3.1. Requirements for network conditioning or filtering at the distribution transformer

It is assumed that no addional filters are required and that the distribution transformer itself acts as a blocking filter in the DLC-VIT4IP frequency range (100-500 kHz).

3.3.3.2. Requirements for network conditioning or filtering at the end user or meter

No addional blocking filters are required to reduce noise from end user equipment or to maintain sufficient line impedance in the DLC-VIT4IP frequency range (100-500 kHz).

It is assumed that sufficient noise and line impedance network conditions are provided by current end use EMC requirements and cable and circuit breakers filtering properties.

3.3.4. Coexistence

3.3.4.1. Coexistence with radio communication and navigation devices

Method of interference and coexistence

[9] J.A. Malack and J.R. Engstrom, 'RF Impedance of United States and European Power Lines', IEEE Transactions on Electromagnetic Compatibility, Vol. EMC-18, No.1, February 1976, pp. 36-38.

Power line modems can interfere with radio communication or navigation systems that operate in the same or neighbour frequency band.

Strong electromagnetic field emission can be caused by standing waves in cables. The typical wave length for frequencies between 10 and 500 kHz is between 30000 and 600 meters. As low voltage grids have typically cables up to 1000 meter this radiated emission is unlikely in low voltage distribution systems. **Bundled or unbundled overhead lines in medium voltage distribution systems could cause interference,** as these lines are significantly longer and standing waves could occur at fractions or multiples of the wavelength (λ/4, λ/2, λ, 2 λ).

Unbundled cables can emit significant magnetic fields when they act as a kind of loop antenna due to 'amperes law'. A loop antenna emits a directional magnetic field and its functioning is identical to a single turn coil, a typical so-called 'small loop antenna' contains no more than 0.085 wavelengths (λ/12) of wire the electromagnetic field radiation of these antennas is typically perpendicular to the loop. Therefore, the application **of DLC-VIT4IP power line modems (100-500 kHz) can interfere with radio transmission and navigation systems when they are used on unbundled overhead lines**, e.g. typically uninsulated overhead lines as used in older rural distribution systems.

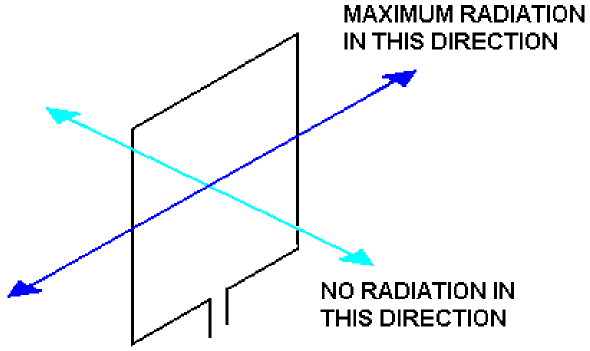


Figure 31: Radiation of a typical loop antenna

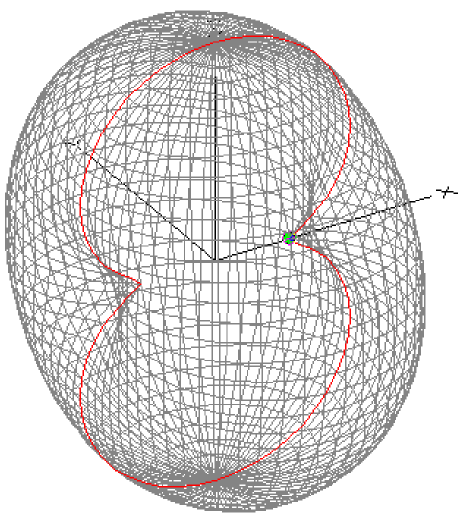


Figure 32: Magnetic field radiation pattern of a loop where the loop is in the Y-plane

Wherever overhead lines are used in the low voltage grid, the problem could occur. Distribution transformers will act as blocking filters and isolate one voltage grid from another.

Interference and coexistence with Long Wave (LW) and Medium Wave (MW) radio broadcasting

Several Long Wave (LW) broadcasting stations operate between 148,5 and 285 kHz. The main functionalities are low cost receivers and long distance broadcasting. A list of stations and frequencies can be found at http://www.dxinfocentre.com/lw.htm. For Europe the Medium Wave (MW) broadcasting band ranges from 526.5 kHz to 1606.5 kHz, hence for DLC modems also the 1/3 rd range of 176 kHz to 535 kHz is relevant when they emit third harmonics. Those LW and MW radio systems use Amplitude Modulation (AM) and therefore interference with radio reception can simply be expected as background noise that reduces sound quality. Due to LW radio broadcasting several strong radiated and conducted emission limits (e.g. CISPR 22/EN 55022, CISPR15/EN 55015, ..) start at 150 kHz. **The use of these LW radio stations becomes arguable** because these stations could migrate to internet or MW radio services and **therefore the project will not target to reduce this interference anymore.**

Interference and coexistence with Non Directional Beacons (NDBs)

The Non Directional Beacon (NDB) is a transmitter which radiates a carrier signal in the range 255kHz to 526.5kHz and is **used for navigation**. **The European NDB band is from 280 kHz to 490 kHz.** Those NDB are mainly used for the aeronautical and maritime radio navigation services and/or terrestrial Differential Global Positioning Applications (DGPS). The frequency assignment plan for the European maritime area is mainly located in the 283.5 - 315 kHz band, those transmitters are most often also equipped for Differential Global Positioning System (DGPS). DGPS is an accuracy enhancement to the Global Positioning System (GPS). Therefore NDB stations between 283.5 and 315 kHz also broadcast the difference between the positions indicated by the satellite systems and the known fixed positions. Due to the DGPS application some NDBs are installed inland. Frequencies above 315 kHz are mainly used for aeronautical radio navigation. Associated Automatic Direction Finder (ADF) avionics are widely used to support en-route navigation and airport approach procedures. For aeronautical navigation the carrier is amplitude modulated by a tone of either 400Hz or 1020Hz which is used to key a two or three letter Morse identifier. For the UK, the minimum desired field strength is 70 mV/m, which is specified in the ITU Radio Regulations Appendix S12. Due to these applications emissions of DLC power line modems have to be considered closer when planning to use the frequency band above 280 kHz on unbundled overhead lines. This is in addition to EN55022 and additional, country specific regulations which have to be taken into account as well. Differences in modulation techniques between NDB and PLC should avoid NDB transmission errors and provide therefore a form of coexistence but interference would reduce the NDB detection range.

Interence with the international maritime distress (emergency) frequency and amateur radio communication bands

This system is also called NAVTEX (Navigational Telex) and was used until 2007. NAVTEX was a simple Morse based communication system that used frequency 518 kHz or 490 kHz. Recently the obligatory emergency Morse code service have been abolished and was replaced by MF (>2 MHz) for offshore and VHF for coastal emergency communication. Therefore this band has been released since 2007 for radio communication with restricted power, e.g. in Belgium this band was recently assigned to radio amateurs. For DLC modems also the 1/3 rd range (around 170 kHz) was important when they emit third harmonics.

3.3.4.2. Coexistence with other powerline communication systems

Coexistence between different powerline communication systems is an important issued. The power line is a shared medium, and hence coexistence with neighboring networks and systems is important for the successful deployment of a powerline system. The DLC+VIT4IP system should allow for coexistence with other systems to allow the parallel use of existing systems, yet to still achieve good performance in terms of throughput and quality of service (QoS) the following requirements should be considered:

Coexistence with Broadband Powerline Communication

Like with broadband PLC high data rate narrowband PLC systems are all using multi-carrier modulation (MCM) like OFDM or DMT with strong forward error correction. These systems use either the frequency bands specified in EN 50065 (CENELEC) between 9 – 148,5 kHz or frequency bands below 500 kHz. Due to the lower radiation and higher tolerance values for these lower frequencies the electromagnetic compatibility (EMC) is no problem.

ETSI and CENELEC standardized the following separation of frequency bands between narrow-band and broadband systems: narrowband systems are below 500kHz and broadband systems between roughly 1 MHz and 30 MHz whereas the lower 10 MHz are dedicated to Access Systems on the last mile and the higher 20 MHz for indoor systems.[10]

Due to the different frequencies and the large distance between the frequency bands a coexistence of narrowband PLC and broadband PLC on the same powerline is possible without any influence on both sides. The telecommunication and Internet activities of the utilities over power line remain untouched.

Coexistence with Indoor Powerline Communication

Since many indoor PLC systems are broadband systems coexistence is mostly given by division of frequency bands. Moreover, the attenuation at the metering point will separate the indoor network from the LV distribution grid in terms of PLC. Proper attenuation at the metering point allows for coexistence between indoor PLC systems and the DLC+VIT4IP system, which foresees communication only to the termination point of the distribution grid.

Countermeasures to Interference

The available frequency spectrum in the PLC is a limited resource that should be shared in a fair manner. The use of different frequency bands enables the coexistence of several logical networks on the same physical network.

Organizational measures such as the reservation of frequency bands by the network owner might be taken to allow for coexistence of different PLC systems. Yet, this solution can heavily limit performance since unused bandwidth cannot be used. In particular, if some systems only affect a limited part of the network a global reservation deteriorates performance strongly.

Additionally, a separation of frequency bands is affecting the QoS since different bands have different transmission characteristics. E.g. the noise level and the variability of disturbances tend to be higher at lower frequencies while the path attenuation Is generally higher in the upper frequency bands.

Automatic counter measures such as the avoidance of used (small) frequency bands or robust modulation such as OFDM are preferable. DLC+VIT4IP should be able to adapt to narrow band systems such as street lighting systems.

[10] CENELEC allocates the band between 1,6MHz and 12,7MHz to access systems and 14,35MHz to 30MHz to inhome systems, whereas ETSI proposes the split at 10MHz

The following countermeasures are potential candidates for the DLC+VIT4IP system to offer a strong capability of co-existence:

1. Attenuation: Attenuation between systems is the best way to guarantee co-existence. In particular between MV and LV the transformer station allows for independent operation of different systems in the network system. The same can be applied to the termination point at the customers premesis[11]. This counter measure is inline with the DLC+VIT4IP concept that foresees a seperation of the physical layer at these points.
2. Arbitration of (sub-)carriers: The PLC system in DLC+VIT4IP should avoid used (sub)-carriers if possible. Alternatively special modulation schemes should be used to avoid interference with other narrow band systems such as street lighting. E.g. the robustness of OFDM will allow to ignore "distrubances" up to a certain limit. Such measures are already used such as by the G3 standard.
3. Medium acces support: Mechanisms such as CSMA access schemes can support coexistence, since occupied channels are not used. Nevertheless, a very high number of nodes reduces the efficiency of this medium access control mechanism.
4. Detection mechanisms: To reduce the implementation effort also detection mechanisms that only detect the presence of an competing system can assist in identification and countermeasures. Proper FDM (Frequency Division Multiplex) or TDM (Time Division Multiplex) countermeasures might be taken based on this information.
5. Collaborative Negotiations: This approach not only uses beacons to detect other systems but also actively communicates to avoid interference. For FDM and TDM systems such a system can optimize the use of the available resources. Problematic about this approach is that all systems need to be benign to cooperate on a solution. The IEEE working group P1901.2 is currently investigating these approaches.

Independent of the used counter measure the following general requirements should apply to the coexistence measures:

1. Minimal deteriotation of system performance and in particular data throughput
2. Vendor and system independent
3. Optimzation of aggregated performance of system, which are coexsiting in the same network.

3.3.5. Physical Layer

<u>Bi-directional communication</u> is necessary.

Due to the fact that the transmission channel is expected to be time-variant with abrupt changes measurements of the channel and retransmission of the channel information to the transmitter is not feasible. Consequently it has to be assumed that the transmitter has <u>no information about the transmission channel.</u>

[11] According to the ETSI report TR 102 269 V1.1.1 (2003-12) 80% of the attenuation between flats or houses is above 50dB for broadband PLC. Also new shunt-based electronic meters will reduce this attenuation.

The receiver has to be able to accept a wide dynamic range of the received signal, due to line impedance variations and impulsive noise.

3.3.6. MAC Layer

According to the (H. Hrasnica, 2004) the main tasks of the MAC layer are: organization of multiple access, resource sharing and traffic control. By the multiple access scheme the transmission resources are divided into accessible sections, which further are used to transmit the information between network stations. Uplink, downlink traffic control and some additional functions (traffic scheduling, admission control) are also the part of the MAC layer. To fulfill the QoS requirements the MAC layer has to support different procedures of traffic scheduling and Connection Admission Control (CAC) mechanism. The factors that have direct impact on the PLC MAC layer are (Figure 33: Environment of PLC MAC Layer Figure 33): network topology, disturbance scenario, telecommunications services and applied transmission system. To analyze their influence on the PLC network, different disturbance and traffic models are used. The core of the MAC layer consists of two components, which are the multiple access scheme and the resource sharing strategy (a MAC protocol). The mechanism of dividing the transmission resources into the accessible sections depends on the PLC physical layer. As the PLC channel operates under the noisy conditions, the multiple access scheme and the MAC protocol must satisfy the QoS requirements and be robust against disturbances.

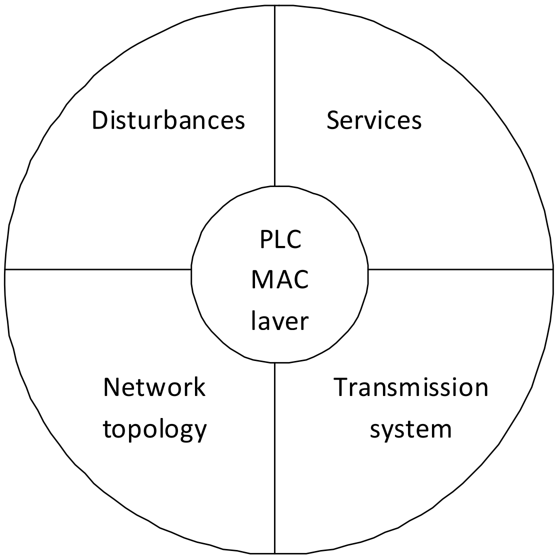


Figure 33: Environment of PLC MAC Layer (H. Hrasnica, 2004)

According to the mentioned above, the requirements for MAC layer are:

- Fairness – fair distribution of channel resources (time or carrier numbers)
- QoS requirements – low latency, delay
- Efficiency – efficient bandwidth utilization
- Reachability – the reachability of the nodes must be 100%

Further requirements result from the following issues:

- The hidden node problem [reference to be supplied] on power line has to be considered when using carrier sensing techniques.

3.3.7. Security Layer Requirements

They goal of the DLC+VIT4IP project is to utilizes the Internet Protocol (IP) layer for communication within the power grid for all kinds of data and applications. Protection of the transmitted data is of high relevance since the communication of utility is critical to control the distribution grid.

In conformance with security standards such as(ISO / IEC, 2005), in the following the requirements and most important boundary conditions for the security system are given. A detailed elaboration of these security needs will be given at a later stage of the project especially during the activities in WP3.

3.3.7.1. Involved entities

There are many parties involved in the process of using, operating, and maintaining the electrical grid. In particular, the main entities are:

- Service provider: Producer, transmitter, supplier, and distributor;
- Customers: private, commercial or industrial consumers;
- System operators and maintainers of the DLC+VIT4IP infrastructure;
- Unknown third parties

The DLC+VIT4IP security system must be able to support these roles in the system. Since the DLC+VIT4IP project only defines a communication system and not the full application environment the security measures in the communication system needs to provide a reliable infrastructure. In particular the parallel traffic of these parties must be managed and a clear separation and mutual protection of data must be guaranteed. Different access rights to the above parties must be foreseen.

3.3.7.2. Entities to be Protected

Equipment

The equipment is the hardware which is deployed within the DLC+VIT4IP network, this includes e.g. meters, access points, metering/SCADA equipment etc. Physical security is typically relevant here.

Physical security is outside the scope of the DLC+VIT4IP project. Nevertheless the security concept will handle the secure storage of security relevant data such as keys, access lists or other credentials and if offered and feasible within the used powerline system will also use existing security measures.

Network Traffic

The protection of network traffic focus on the protection of the transmitted is Internet Protocol (IP) messages. In case of DLC+VIT4IP the information transport is packet oriented and connectionless. The connection between the entities can be pull or push depending on the application which triggers the request and the initiator of the request.

Applications

Application security is not in the scope of the project. The DLC+VIT4IP project only requires to offer basic secure communication services to protect application traffic. Since all communication is using IP the DLC+VIT4IP system should best offer existing security services such as IPsec to allow the best transparency of the communication system to the used applications.

3.3.7.3. Hazards and Risks

Security is all about finding the trade-off between risk, costs, and convenience expressing all aspects of efficient use of the system.

A general list of hazards and risks includes the following items:

- Direct manipulation of values input/output
- Manipulation and replacement of equipment
- Traffic manipulation/injection of data into the PLC network
- Manipulation of the backbone infrastructure, e.g. servers
- Denial of Service (DoS)

Access to Shared Medium

The Power Line Communication (PLC) system in the electrical grid is a shared medium with restricted channel capacity for the data that is accessible by everybody. Everyone who has access to a connection to the distribution grid is capable to eavesdrop, manipulate or disturb communication. Depending on connection point the affected network segment can range from a single household to a big company and building to large segments of the network.

Although the physical access to the powerline network can be hardly limited[12], the system must protect against illegitimately inserted nodes and messages and at least mitigate disturbances to keep their effect local and prevent a decrease of QoS and availability of the overall network.

Restricted transmission capacity

Within the Power Line Communication (PLC) network the capacity available for each node depends highly on the amount of nodes connected to this line. As pointed out in “Shared Medium/Accessible by Everyone”, the PLC network is a shared medium; therefore the channel capacity is divided by the amount of the nodes connected to the line.

Hence the network security concept must be optimized for this scenario of limited channel capacity.

Exchanging Confidential Information

Due to the fact that the Power Line Communication (PLC) is based on a shared medium confidentiality is not given. Therefore messages which carry classified or sensitive information must be encrypted to guarantee a secure connection. Depending on the application this connection must be secure either Point-to-Point or End-to-End. In a network where data from specific users is collected confidentiality is must. This highly depends on the provisions of local laws which apply on the distribution of sensitive user data.

Integrity and Authentication of Messages

Messages which traverse the PLC network can be altered in any device which is passed on the route. To avoid malicious behaviour the message integrity must be protected. The integrity protection is usually provided via an Integrity Check Value (ICV). The calculations of ICVs are based on one-way cryptographic algorithm. This value is a unique fingerprint of the data. If an attacker changes a part in the message the ICV on the receiver side would not match the ICV which was sent with the message. Thus the attempt of manipulating the message is detected.

Additionally to the integrity check it is crucial to know who sent a specific message. For example a meter measures the power consumption and sends these values to the billing server of the provider. These values build the basis for the billing of the companies. If the submitted values cannot be traced back to the consumer the company cannot verify the consumption for a specific user.

3.3.7.4. Security Boundaries

Modern technical systems, especially communication systems, interconnect with different environments. Security needs clear borders to define appropriate security measures. Based on the different scenarios from chapter 1.2 and 2.1 the requirements for the security layer can be collected.

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[12] Medium Voltage and High Voltage lines offer some inherent protection due to the physical risks of applying connectors.

3.3.7.5. No Security by Obscurity

A very important principle for the design of a secure system is based on Kerckhoffs assumption, which demands that the security of a system must only rely on the keys used. Even if an attacker has full knowledge about the system he must not be able to gain access to the information, without the required credentials.

3.3.7.6. Ubiquitous security

A key element for the overall system design of DLC+VIT4IP is the inclusion of security from the very beginning. The security in this project is not just a feature it is tightly integrated with every part of the system to provide a comprehensive security architecture. With this approach the system can be adapted to new situations and provide the users a secure environment to work in.

3.3.7.7. Security Goals and Services

The general requirements of security needs to protect

- Confidentiality of data, which only allows authorized entities to access the data,
- Integrity of data, which assures that data is not manipulated,
- Authenticity of data, which guarantees that the data is sent by a dedicated entity, and
- Availability of data, guaranteeing that data is available when needed.

Based on the results from the previous section the following security services must be offered by the DLC+VIT4IP architecture:

- Secure management of nodes
- Device security, physical protection, protection against tampering (conceptual foreseen, yet only implemented in DLC+VIT4IP if offered by the existing hardware)
- Secure system behaviour including blackout resilient and viable system design
- Authorization and access control for the smart grid
- Cryptographic mechanisms and key management appropriate for smart grids
- Integrity protection
- Mutual confidentiality of user data from different entities
- End-to-end and point-to-point security, depending on application
- Availability of data

3.3.8. Higher Layers

Each system on the PLC network must have a unique system identifier, so that the source and the destination of all information can be unambiguously identified.

Each system/device/application must be have a unique address. This address is used for all

broadcast / multicast / unicast communication.

3.3.8.1. Network Layer

Internet Protocol Version 6 (IPv6)

The requirements for IPv6 protocol are specified by the Internet Engineering Task Force (IETF) in Request for Comments (RFC) 4294 named “IPv6 Node Requirements”. Three types of IPv6 devices are defined by the [RFC-2460] “IPv6 Specification”:

- IPv6 node – “a device that implements IPv6” [RFC-2460]
- IPv6 router – “a node that forwards IPv6 packets not explicitly addressed to itself” [RFC-2460]
- IPv6 host – “any node that is not a router” [RFC-2460]

IPv6 can node can be either router or host (Fig. 3.7.1)

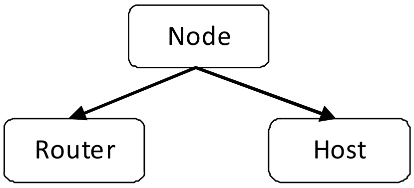

Figure 34: IPv6 Nodes

The following specifications MUST, SHOULD, RECOMMENDED, or MAY be implemented for IPv6 routers and hosts:

Req#	Specification	Router	Host
1	IPv6 Specification [RFC-2460]	MUST	MUST
1.1	Ability to send, receive, and process fragment headers	MUST	MUST
2	Neighbor Discovery [RFC-2461]		
2.1	Router Discovery		MUST
2.2	Prefix Discovery		MUST
2.3	Neighbor Unreachability Detection		MUST
2.4	Duplicate Address Detection		MUST
2.5	Sending Router Solicitations		MUST
2.6	Receiving and processing Router Advertisements		MUST
2.7	Sending and receiving Neighbor Solicitation		MUST
2.8	Sending and receiving Neighbor Advertisement		MUST
2.9	Redirect functionality	MUST	
2.10	Sending Router Advertisements	MUST	
2.11	Processing router Solicitation	MUST	
3	Path Maximum Transmission Unit (MTU) Discovery [RFC-1981]	SHOULD	SHOULD
4	IPv6 Jumbograms [RFC-2675]	MAY	MAY
5	Internet Control Message Protocol Version 6(ICMPv6) [RFC-2463]	MUST	MUST
6	IPv6 Addressing Architecture [RFC-3513, RFC-3879]	MUST	MUST

7	IPv6 Stateless Address Autoconfiguration [RFC-2462]		MUST
7.1	Ability to generate link local addresses	MUST	
8	Privacy Extensions for Address Configuration in IPv6 [RFC-3041]	SHOULD	SHOULD
9	Default Address Selection for IPv6 [RFC-3484]	MUST	MUST
10	Stateful Address Autoconfiguration [RFC-3315]	MAY	MAY
11	Multicast Listener Discovery (MLD) for IPv6 [RFC-2710]		
11.1	MLDv2 [RFC-3810]	SHOULD	SHOULD
11.2	MLDv1 [RFC-2710]	MAY	MAY
12	Domain Name System (DNS) Stub-resolver functionality [RFC-1034]	SHOULD	SHOULD
13	DNS security extensions [RFC-4033], [RFC-4034], [RFC-4035]	RECOMM.	RECOMM.
14	Dynamic Host Configuration Protocol for IPv6 (DHCPv6) [RFC-3315]	MAY	MAY
15	IPv4 Support and Transition	MAY	MAY
16	Transition Mechanisms for IPv6 Hosts and Routers [RFC-2893]	MUST	MUST
17	Mobility support in IPv6 [RFC-3775]	MAY	MAY
18	Security Architecture for the Internet Protocol [RFC-4301]	MUST	MUST
19	IP Encapsulation Security Payload (ESP) [RFC-4303]	MUST	MUST
20	IP Authentication Header (AH) [RFC-4302]	MUST	MUST
21	Cryptographic Algorithm Implementation Requirements for ESP and AH [RFC-4305]	MUST	MUST

Table 18: Requirements for IP hosts and routers

From the RFC-4294 not all the IPv6 specifications are required to be implemented. So, in Table 18 the minimum IP node requirements are marked with the red, recommended for DLC networks – with yellow, and not necessary for DLC networks – with green. Req. #3 is not obligatory for implementation when there is no need to support the large packets. The implementation of #4 gives the ability to transmit the packets with a payload longer than 65535 octets. This feature is also not required in DLC system and can be ignored. #11.2 is the old version of the protocol and that's why #11.1 should be implemented. #14 and #15 are under consideration. As the nodes in DLC network are not mobile, it is not necessary to implement #17.

All the requirements mentioned before are the requirements for general IPv6 nodes and routers. Depending on the DLC nodes implementation even some of these MUST requirements can be avoided. If routing in DLC network is done under the IP layer, a huge IPv6 routing overhead can be avoided. In this case a lot of MUST requirements will be not implemented. However, this must not have any impact on the compatibility of end devices and IPv6. That's why here all the requirements for the IPv6 nodes and routers are listed and the need for implementation of every requirement specified in the requirements protocol will be defined during the development of the convergence layer.

3.3.8.2. Application Layer

Since the different Power Grid applications could be managed by different dispatchers belonging to different administrative and autonomy groups, these applications shall be separated at least logically. Therefore, a VLAN architecture is highly recommended.

Virtual LAN (VLAN) management allows an DLC network to be separated into different independent isolated sub-networks that can be managed independently.

As the trend is clearly towards the use of very well standardized communication platforms and in particular towards TCP/IP, there is still a vast amount of equipment in the field using older protocols and standards, not to mention, that in the past a lot of vendors used their own proprietary systems and protocols. However, the scope and the boundary of the project is IP over PLC and therefore no additional convergence layers, apart from the IP convergence layer, have to be developed. Equipment without TCP/IP functionality has to be connected through an IP proxy device, performing the ‘equipment specific communication protocol’-to-IP translation. The development of this IP proxy device is not in the scope of this project.

The main open protocols over IP used for SCADA are:

- Modbus TCP
- IEC 60870-5-104. The IEC 60870-5-x standard deals with communication between substation equipment and the central network operation centre. The IEC 60870-5-101 standard describes telecontrol (SCADA). The IEC 60870-5-104 standard in particular describes telecontrol (SCADA) over IP.
- DNP3 IP. DNP is a variation of IEC 60870-5-101, especially used in United States and Canada.
- IEC 61850, mostly used for communications between objects within a (HV / MV / LV) station, but also in between stations and central SCADA installations.

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5. Appendix I

5.1. Definitions

Terminology	Description
Access Point	node interconnecting DLC+VIT4IP intranet and DLC+VIT4IP DLC network
Base Station	node interconnecting two DLC+VIT4IP DLC networks or DLC+VIT4IP DLC network and DLC+VIT4IP intranet (i.e. Access Point or Bridge)
Bridge	node interconnecting MV DLC and LV DLC networks
Node	node interconnecting utility devices to LV or MV DLC network
Transmission System Operator	party operating a transmission system (IEV 617-02-11)
Distribution System Operator	party operating a distribution system (IEV 617-02-10)
Transmission Power Network	Electric network from Power Plant to the HV/MV substation
Primary Distribution network	Electric network from HV/MV substation to MV/LV substation
Secondary Distribution network	Electric network from MV/LV substation to the consumers
Substation	a part of an electrical system, con-fined to a given area, mainly including ends of transmission or distribution lines, electrical switchgear and controlgear, buildings and transformers. A substation generally includes safety or control devices (for example protection) (IEV 601-03-02) NOTE – The substation can be qualified according to the designation of the system of which it forms a part. Examples: **transmission substation** (transmission system), **distribution substation**, 400 kV or 20 kV substation
High Voltage (U > 35kV)	(IEV 601-01-27) 1) in a general sense, the set of voltage levels in excess of low voltage (> 1kVac) 2) in a restrictive sense, the set of upper voltage levels used in power systems for bulk transmission of electricity Nomenclatures used to represent different high voltage levels: - High Voltage: 35kV < V $\leq$ 230kVac - Extra High Voltage: 230kV < V $\leq$ 800 kVac
Medium Voltage (1kV < U $\leq$35kV)	any set of voltage levels lying between low and high voltage (IEV 601-01-28) NOTE – The boundaries between medium and high voltage levels overlap and depend on local circumstances and history or common usage. Nevertheless the band 30 kV to 100 kV frequently contains the accepted boundary. However, the term Medium Voltage is commonly used for distribution systems with voltages above 1 kV and generally applied up to and including 52kVac. Note: The term medium voltage is commonly used for distribution systems with voltages above 1 kV and generally applied to and including 52 kV. For technical and economic reasons, the nominal voltage of medium-voltage distribution networks rarely exceeds **35 kV**.
Low Voltage (U < 1kV)	a set of voltage levels used for the distribution of electricity and whose upper limit is generally accepted to be **1 000 V a.c** (IEV 601-01-26)
Feeder	an electric line originating at a main substation and supplying one or more secondary substations (IEV 601-02-08)
Cable	assembly of one or more conductors and/or optical fibres, with a protective covering and possibly filling, insulating and protective material (IEV 151-12-38) Single core - multi core cable

Terminology	Description
Over Head line	an electric line with one or more conductors or a cable supported above ground by appropriate means (IEV 151-12-33) NOTE 1 – An overhead line may consist of only one conductor when the circuit is closed by the Earth. NOTE 2 – An overhead line may be constructed with bare conductors, generally supported by insulators, or with insulated conductors. NOTE 3 – The concept of overhead line generally includes the supporting elements
Underground cable	an electric line with insulated conductors buried directly in the ground, or laid in cable ducts, pipes, troughs, etc (IEV 601-03-05)
Switchgear	a general term covering switching devices and their combination with associated control, measuring, protective and regulating equipment, also assemblies of such devices and equipment with associated interconnections, accessories, enclosures and supporting structures, intended in principle for use in connection with generation, transmission, distribution and conversion of electric energy (IEV 441-11-02)
Circuit breaker	a mechanical switching device, capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying for a specified time and breaking currents under specified abnormal circuit conditions such as those of short circuit (IEV 441-14-20)
Load-brake switch	a switch capable of making and breaking a circuit under normal but not fault conditions
Switch-disconnector	a switch which, in the open position, satisfies the isolating requirements specified for a disconnector (IEV 441-14-12) NOTE – A disconnector is capable of opening and closing a circuit when either negligible current is broken or made, or when no significant change in the voltage across the terminals of each of the poles of the disconnector occurs. It is also capable of carrying currents under normal circuit conditions and carrying for a specified time currents under abnormal conditions such as those of short circuit.
Earthing switch	a mechanical switching device for earthing parts of a circuit, capable of withstanding for a specified time currents under abnormal conditions such as those of short circuit, but not required to carry current under normal conditions of the circuit (IEV 441-14-11)
Switchboard	part of a manual or manually supervised exchange at which the interconnection of circuits is manually controlled (IEV 714-20-01)
Fuse	a device that by the fusing of one or more of its specially designed and proportioned components, opens the circuit in which it is inserted by breaking the current when this exceeds a given value for a sufficient time (IEV 441-18-01)
Bushing	device that enables one or several conductors to pass through a partition such as a wall or a tank, and insulate the conductors from it (IEV 471-02-01)
Lightning arrestor	A lightning arrester is a device designed to protect electrical apparatus from high transient voltage and regulate the duration and amplitude of follow current

Table : Definitions

5.2. Abbreviations

AP	Access Point
BS	Base Station
CPE	Customer premise equipment
DSO	Distribution System Operator
HV	High Voltage

LV	Low Voltage
MV	Medium Voltage
OH	Over Head
OHL	Over Head line
REP	Repeater
TSO	Transmission System Operator

Table : Abbreviations

6. Appendix II

6.1. Example: European Electricity Network characteristics – Overview

In addition to section 3.1.1 the following tables in this section provide details on the characteristics of European electricity networks using the example of several European countries. As respective information is spread over several companies in most cases, data is difficult to gather and therefore the table is not complete. Nevertheless it gives a good idea of the networks.

6.1.1. MV Network

country DSO	name DSO	Overhead MV lines			Underground MV cables			MV Topology			
		Cable Type	Typical cable length between MV/LV transformer (km)	total (km)	Cable Type	Typical cable length between MV/LV transformer (km)	total (km)	Parallel (Line) (%)	Meshed(%)	Radial or star (%)	Looped (Ring) (%)
BE	All		1,03	7302		1,03	62841		x		
ES	Iberdrola (14(32) provinces)			63321			16548				x
FR	ERDF		0,86	596618		0,86	38082			x	x
IE	ESB		0,38	80002		0,38	7550				
IT	ENEL		0,79	202860		0,79	119140				
Israel	IEC		0,50	15100		0,67	9912				
NL				few			60000		x		x
PL											
Austria											
Germany											
Germany	DSO Berlin□DSO Hamburg	s.a.	s.a.	s.a.	s.a.	s.a.	s.a.	0,1		98	0,1
P	REN			50712			10512		x		x

Table 19: MV electricity network characteristics for several European countries (part 1)

country DSO	name DSO	Substation HV/MV power transformer						
		HV/MV transformer ratings (MVA)	typical rating (MVA)	# HV/MV transformers	High availabilty HV/MV substations (= 2 parallel trafos) (%)	# MV feeders per transformer	MV (kV)	HV (kV)
BE	**All**	20 to 60	50		90%		10/11/12/15/26	380/220/150/70/36
ES	**Iberdrola (14(32) provinces)**	6-200					33	(400/220)/132/65/45 () is not IBERDROLA
FR	**ERDF**	15/20/30/36/40/70/100		2100 stations			15/20	400/225/90/63kV
IE	**ESB**	?					10/20	38/110/220/275/400
IT	**ENEL**	20-25-40-63		1650			10/15/20	132/150
Israel	**IEC**	20/30/45/75		188 SubStations			13/22/33	161/400
NL		?					? ± 10%	380/150/110/50
PL		10-16-25-32-40					6/15/20	110
Austria		20, 32, 40 and 63MVA					10kV urban / 20 kV rural	110kV
Germany							10kV urban / 20 kV rural	380/220/110kV
Germany	**DSO Berlin DSO Hamburg**	31-40		210 in Berlin	0,9		10kV urban / 20 kV rural	110kV
P	**REN**	20		654 (368 stations)			10-60kV	400/220/150kV

Table 20: MV electricity network characteristics for several European countries (part 2)

country DSO	name DSO	Other MV grid characteristics			
		Voltage regulation (Automatic tap changers/ capacitor banks/..)	**MV neutral earthed or isolated**	**Balanced**	**Security**
BE	**All**	Automatic tap charger	earthed	Yes	n-1
ES	**Iberdrola (14(32) provinces)**	Automatic tap charger	?	Yes	n-1
FR	**ERDF**	Automatic tap changer and capacitor banks	Resistance/coil	Yes	n-1
IE	**ESB**	?	?	?	?
IT	**ENEL**	Automatic tap charger	Petersen (60%) Insulated (40%)	Yes	n-1
Israel	**IEC**	Automatic tap charger	Petersen / resistance / solidly earthed		n-1
NL		?	?	?	n-1
PL		Automatic tap charger	Petersen/resistance earthed/insulated	Yes	n-1
Austria		Automatic tap charger	solidly earthed, compensated grounding	Yes	n-1
Germany		Automatic tap charger	solidly earthed, compensated grounding	Yes	n-1
Germany	**DSO Berlin DSO Hamburg**	Automatic tap charger	earthed	Yes	n-1
P	**REN**	?	?	?	?

Table 21: MV electricity network characteristics for several European countries (part 3)

6.1.2. LV Network

country DSO	name DSO	Overhead LV lines or cables						Underground LV cables							
		Area / use	Cable or line type		Length (km)			Area / use	Cable Type		Length (km)			total length (km)	cable per transfo
			Type	Section (mm²)	Typ.	Max.	Total		Type	Section (mm²)	Typ.	Max.	Total		
BE	All	rural	BAXB (Al)	3×95+54,6	0,5	1	53173		EAXVB (Al)	4×150	0,3	0,7	62083	115256	1,70
ES	Iberdrola(14(32) provinces)	rural	2x25Al (see OPERA)				84221	Urban	XC6Z1	3x150 (see opera)			34053	118274	1,63
FR	ERDF	Yes	Almelec	34/54//75/148	0,2	0,6	155320		AL	95/150/240/630	0,3		550680	706000	0,95
IE	ESB		90% single phase		0,05	0,1	54000				0,05	0,1	11473	65473	0,29
IT		Yes	77 % insulated cables		0,5	1	508000				0,4	1	236000	744000	1,83
Israel	IEC	rural		3x150+95; 3x70+54	0,2	1	9412	urban	XLPE	/25/50/150Cu; 95/240	0,2	0,7	9850	19262	
NL		No						All	XLPE		0,5		170000	170000	
PL		Yes			0,5		120358	Yes			0,4		24958	145316	0,61
Austria		rural			0,6	0,8		urban			0,2	0,3			
Germany	DSO Berlin DSO Hamburg	rare	see attachment s.a.	s.a.	s.a.	s.a.	502 (B*)	urban	s.a.	s.a.	s.a.	s.a.	20154 (B*)	20656	s.a.
P	REN	rural/urban					95059	urban					23044	118103	2,40

B*: only in Berlin

Table 22: LV electricity network characteristics for several European countries (part 1)

country DSO	name DSO	Substation MV/LV power transformer							interconnected LV grids (%)	Remote control of LV interconn	% neutral line included	fuse at home 1-phase (A)	fuse at home 3-phases (A)
		MV/LV transformer ratings (kVA)				# MV/LV residential transformers	% residential vs industrial MV/LV transformers in numbers	avg #LV feeders per MV/LV transformer					
			min	avg	max								
BE	All	160-200-400-630	160	250	630	67886	77%	6	100	manual	95%	16-**40-63**	**25-40**-63
ES	Iberdrola(14(32) provinces)	≤ 650 kVA		394		72726	77%	4-15					
FR	ERDF	50-100-160-250-400-630-1000	50	190	1000	740000	77%	6-8	100			90	
IE	ESB	25-40-50-63	25	50	63	229499	77%	5-8 homes					
IT		250-400-630	250	400	630	406000	77%						
Israel	IEC	100-160-250-400-630-1000	100	450	1000	23000	50%	4-8			1	25-40	25 40 63 80
NL		160-200-400-630-1000		630		34783	77%	3-4					
PL		20-40-50-65-125-100-160-200-250-315-400-630	20	190	630	240000	77%	4-8	90		~5%	16-40	40-63
Austria		400-630-800					77%						
Germany	DSO Berlin DSO Hamburg	400 - 630- 800- 1000	400	630	1000		70%	n.n.				n.a.	35-250
P	REN	?	50	273	?	49165	70%	n.n.				?	?

Table 23: LV electricity network characteristics for several European countries (part 2)

country DSO	name DSO			Accounts (EAN)			Street cabinets			Electricty Meter	Street lighting			
		LV protection	Restoration	#accounts per MV/LV transform	#accounts (EAN) per LV feeder	DSO # accounts	# Street cabinets	With fuse (y/n)	With circuit breaker (y/n)	Exterior or outdoor Meter	Street lighting points per capita	% lighitng with separate cable	% with dimming scheme	Average power of lighting point (W)
BE	All	fuses	No	79	15	5377048				no	0,18	95	20	122
ES	Iberdrola(14(32) provinces)	fuses	rare		20-50	14/33 spain				yes?	0,12			122
FR	ERDF	fuses	?	90	9	33600000					0,12			122
IE	ESB	?	?	6	1	2000000					0,12			122
IT		breaker	unusual		31						0,12			122
Israel	IEC	fuses				2300000	171000		n		0,12			122
NL		?	?	200	50-80						0,12			122
PL		fuses	80%		90	15900000					0,12			122
Austria		fuses	urban		urban 20 - 40 rural 5 - 15						0,12			122
Germany	DSO Berlin DSO Hamburg	fuses	urban	10000		2300000	7892	y	y	no	0,12			80
P	REN	?	?	114		5604810					0,12			80

Table 24: LV electricity network characteristics for several European countries (part 3)

6.2. Example: Belgium Electricity Network characteristics - Details

Connection:

1. Basic connection:
   - 1ph 230 V / 40 A => 9,2 kVA
   - Electric heating: 15,9 kVA, 3ph 230 V, 40 A
2. Other connections:
   - 1ph 230V: I = 40/50/63 A => S = 9,2/11,5/14,5 kVA
   - 3ph 230V: I = 25/32/40/50/63/80/100 A => S = 10/12,7/15,9/19,9/… kVA
   - 3ph 400 V: I = 20/25/32/40/50/63/80/100 A => S = 13.8/17,3/22,2/… kVA

Transformers:

1. Ratings: 160/250/430/630 kVA, 250 kVA is standard for residential applications, 630 kVA for industrial.
2. Secondary of transformer is always 3 * 400 V, 1ph 230 V connection is between line and neutral.
3. Clock hour number of Dy5 or Dy11: allows the parallel connection of transformers without loop currents

Cables:

1. Low voltage network consists of 4 * 150 mm^2 cables in aluminium, with +- 220 A current rating, in residential area and 4 * 95 mm^2 cables in aluminium outside residential areas.
2. A <u>maximum of 25 households is connected to the cable</u>. At 24 A/hh (see later), this gives 8 * 24 A in each phase or 192 A per phase. At 220 A/phase * 0.85 (reserve factor) = 187 A, both figures match.

Power Quality:

1. Max. voltage drop of 4 %
2. Grid extension:
   a. Check current load of transformer and cable.
   b. The new load may cause a maximum voltage drop of 2.5 %, total voltage drop may not exceed 4 %.
   c. If the values are exceeded: separate LV cable. If this is still insufficient: separate MV cable + transformer
3. LV-grid: Cos ϕ of 0.9 for loads, cos ϕ of 1 for solar panels.
4. MV-grid: Minimal cos ϕ of 0.9 for loads, 0.99 for generation, mostly automated capacitor bank if cos ϕ is below 0.9.
5. Harmonics in grid are measured at MV-rails: must be in accordance with local regulations.
6. Since the secondary Y is only earthed at the transformer, a large current unbalance between the lines can not cause an earth reference point translation at the transformer, but it can do so at the

household connection. Therefore the distribution network operator is not eager to install a 50 or 63 A single phase connection if for e.g. charging a PHEV. The DNO would prefer a three phase 400 V connection in that case of 20 A/13.8 kVA or 25 A/17.3 kVA.

Power ratings for households:

1. A 0,8 Utilisation Factor (UF) is applied to account for the fact that the maximum power is seldom used. This UF is used for individual connections, shops and allotments.

2. A Simultaneity Factor (SF) is used that accounts that not all connections use the maximum power simultaneously.

3. Rule of thumb for the number of electrical heatings:

   When gas distribution is present: 4 % electrical heating

   When gas distribution is not present: 20 % electrical heating

Rating of one individual household:

5,5 or 4,4 kVA => 24 or 19 A per household.

Power ratings for small and medium enterprises:

Transformer is standard at 630 kVA

An individual SME can have a maximum connection of 3ph 400 V / 100 A = 69.2 kVA by a separate cable starting from the transformer. If the connection is above 69.2 kVA the MV grid is extended to the SME and a separate transformer is placed.

Design of MV grid:

1. Grid is powered by one 20/40/70 MVA HV/MV transformer and one reserve or two transformers and one reserve: N-1 reliability for transformers. HV-grid is N-1 itself: feeds through different HV-lines (or cables) at 70 … 150 kV.
2. MV substation is connected with 15-20 medium voltage (MV) feeders, mostly at 15 kV. MV cable consists of 3 monopolar cables, 3 * 95 mm^2 aluminium. Feeds 10-20 distribution transformers. If MV cable is cut in between two distribution transformers the fault is isolated by opening the appropriate switches at the distribution transformer. By closing the end-switch at the end of the neighbouring MV cable, the power to the remaining distribution transformers is restored. This cable will now provide power to the DT that were disconnected by the fault. The MV cable is designed to withstand the current drawn by his own DT + the DT of the other MV cable.
3. In each distribution cabin one MV/LV transformer is present. The transformer feeds several LV lines. An LV lines consists of 4*150 mm^2 cables with a line voltage of 400 V. The LV cables are fused at 250 A. They feed a maximum of 30 households. The transformers are all of the type Dy11 which allows them to be put in parallel without loop currents. If the transformer should fail, the transformer can be isolated from the MV and LV grids. The LV cables can be powered by a diesel generator or an LV cable coming from another distribution cabin. The LV cables can be put in parallel before the transformer is disconnected to avoid loss of power to the LV customers.

4. The network is operated at 85 % of its capacity to cope with future growth of demand.
5. The transformers are oil cooled, dry transformers are only used when fire prevention is essential such as in hospitals. Oil cooled transformers have lower losses, less inrush current and provide better cooling.
6. When there is a large unbalance between the currents drawn in each line, a transformer with a primary Y-connection and secondary zigzag-connection is used. This divides the phase current over 2 primary windings and (partially) solves the translation of the earth reference point.

6.3. QoS parameters – further details

		QoS parameters												
		Critical (1)	Desiable (2)	non critical (3)	Priority	datarate (kbit/s)	traffic type	Min. latency (s)	Ma. Latency (s)	Max Jitter (ms)	BER	UPS	Max time of network recovery (sec)	% coverage
Communication Content	1-Tele-control	X			yes	9,6	Random		0,5	NA	NA	Yes	1	10 to 15
	2-Tele-control (Fault detection)	x			yes	9,6	Random		NA	NA	NA	Yes	15	> 50
	3-Operational Telephony	x			yes	8	Random		0,5	30	1,00E-03	Yes	15	< 10
	4-Corporative application access		x		no	2000	Random		1	NA	1,00E-05	Yes	NA	< 10
	5-Video surveillance		x		no	256	Continuous		1	NA	1,00E-04	Yes	NA	< 10
	6-Video supervision		x		no	64	Periodic		NA	NA	1,00E-04	Yes	NA	< 10
	7-Alarm Management (Temp., humidity, gas,…)		x		yes	9,6	Random		30	NA	NA	Yes	15	10 to 15
	8-Tele-measurement. Product and Power quality			x	no	9,6	Periodic		NA	NA	NA	No	NA	> 30
	9-Protection Tele-measurement.			x	no	64	Random		1	NA	1,00E-05	No	NA	< 10
	10-Operation/supervision telecom network			x	no	(4)	Continuous		1	NA	1,00E-04	No	NA	10 to 15
	11-AMR/AMM		x		no	(5)	Periodic		NA	NA	NA	No	NA	> 95
	12-Load Management, DSM		x		no	2000	Periodic		1	NA	NA	No	1	10 to 15

Table : technical requirements and service cataloguing of twelve electrical services for automating MV and LV electrical network according [CIGRE]

The preceding table shows the relevant QoS parameters for different types of data content representing twelve electrical services for automating the MV and LV electrical network, in terms of technical requirements and service cataloguing (critical, desirable and non-critical) for utilities. (Source:CIGRE,WG D2,21, June 2008.)

Notes to table:

(1) Redundancy of physical telecom. Network and continuous power supply.

(2) Availability not dependent on power supply.

(3) Medium and long-term non-availability allowed.

(4) this depends on the number of facilities installed and the operation and supervision purposes.

(5) This depends on network architecture.

(Further) notes to table:

- The requirements for video surveillance depends on the video resolution, the number of captured and sent frames, the codec and if the video capturing is event based or continuous. For instance in common intermediate format (CIF; 352 x 288) at 1 frame per second requires about 15 kbps upstream, at 4 frames per second 36 kbps and at 10 frames per second 128 kbps.
- Further details with respect to required data throughputs are given in appendix section 1.1.
- UPS : Uninterruptible power supply
- ###FIXME Coverage : how to interprete here, i.e.... what is the meaning of coverage 10%?
- Corporative application access: what does that mean?

The following table provides a basis for the estimation of required throughputs based on the considered core applications:

- (Extended) Meter Management
  - Meter reading
  - Power quality data
  - Control actions, include demand side management
- Monitor (grid) objects and Control Grid objects
  - Combined as “SCADA”
  - Application functions on top of “SCADA”:
    - Distribution management: outage detection, fault detection, service restoration, …
    - Demand management
    - Distributed generation control

Item	Minimum	Maximum	Average	Typical size	# per station
(Extended) Meter Management:					
Read e-value	1 value / 60 min	1 value / 3 min	1 value / 15 min	32 bytes	
Read G-value	1 value / day	1 value / 15 min	1 value / hour	32 bytes	
Read W-value	1 value / day	1 value / hour	1 value / 12 hours	32 bytes	
Read meter status	By exception	Once / hour	By exception	16 bytes	
Set Control status	1 per year	1 per 5 min	1 per hour	32 bytes cmd 16 bytes ack	
Set value	1 per year	1 per 5 mi	1 per hour	32 bytes cmd 16 bytes ack	
Read quality data	Exception	1 / minute	1 per hour	48 bytes	
Monitor Grid Object:					
Read status	By exception	1 / 10 sec	By exception	16 byte	128
Read value	By exception	1 / 10 sec	By exception	32 byte	16
Control Grid Object:					
Set status	1 / day	1 / minute	1 / hour	16 byte ctl 8 byte ack	32
Set value	1 / day	1 / minute	1 / hour	32 byte ctl 8 byte ack	8

Table 25: Throughputs based on the considered core applications

The table below summarises the time and data size requirements for some typical transactions with advanced meters. For approximately 3 million electricity meters (e.g. Flanders region) this requires about 0.5 MiB per meter per year for reading the meters monthly. If not only monthly measurements registers need to be transferred, but also 15 min profile data needs to be transmitted or if detailed power quality data needs to be sent, then the amount of data per meter can increase with 2 or 3 orders of magnitude (Deconinck, 2008)

Transaction type	Time critical	Response (min/typ/max)	#times/ year	#data (min/typ/max)
Command store measurement registers	Yes	Immediate / 5 min / 1 h	1	0.5 kB / 1 kB / 16 kB
Send measurement registers (periodically + on demand)	No	Immediate / 10 min / 2 h	13 (12 + 1)	1 kB / 32 kB / 16 MB

Command reduce load	Yes	Immediate / 5 min / 1 h	1	0.5 kB / 1 kB / 16 kB
Adjust parameters	No	Immediate / 10 min /2 h	2	0.5 kB / 1 kB / 16 kB
Upgrade firmware	No	10 min / 2 h / 1 day	0.2	0.5 kB / 1 kB /512 kB
Send alarms	No	Immediate / 10 min / 2 h	0.2	0.5 kB / 1 kB / 16 kB

Table 26: Time and data size requirements per transaction type per meter (Deconinck, 2008)

Application	**Basic Description**	**Upstream data per node (byte)**	**Downstream data per node (byte)**	**Permissible latency**	**Scheduled**
Meter readings - data collection	Collection of daily interval reads of individual meters	2000-10000	50-400	Up to 8 hours	Yes
Meter readings - on demand	A request of immediate parameters such as consumption or the presence of power or other parameters	100-500	50-100	1- 5 seconds	No
Demand response - broadcast of data	A system-wide broadcast of data to demand response or in-home energy display units	40-100	500-2000	1-60 seconds	Yes
Demand response - directed control of individual premises	Directed control messages to devices at customer premises. Includes confirmation of delivery	40-100	200-500	1-5 seconds	No
Outage detection	A message indicating loss of electricity supply from a given device	100	0	1-5 seconds	No
Fault detection	A message indicating a fault has occured and including some basic measurement parameters	100-300	0	1-5 seconds	No
Distributed switch control	Control message to switches or other devices in the distribution system	50-300	250-1500	1-2 seconds	No
Distributed generation-predispatch reporting	Messages to distributed generation resources (such as solar panels or PLEVs) to prepare for generation dispatch	50-2000	1000-3000	1-2 seconds	No
Distributed generation - dispatch	Messages to dispatch distributed generation resources	100-200	100-200	1-2 seconds	No
Distributed generation - status reporting	Reporting status from distributed generation resources during their operation	250-1000	50-200	1-2 seconds	No

Software download	Download of new software for devices in the field	10 kilobytes - 100 kilobytes	100 kilobyte - 10 megabyte	< 24 hours	Yes

Table 27: Throughput and latency requirements according to DCN 2030-10-0020-00-0012

Further requirements with respect to throughput are given by the following consideration according to (Rempli 7-1, 2003) which considers data transfers for metering and SCADA applications for normal, heavy and peak loads.

For normal load in the network the following assumptions can be made:

- sporadic metering requests from operators (10 requests/h)
- sporadic controls to SCADA (5 controls/h)
- sporadic alarms from SCADA (20 alarms/h)
- cyclical measurement of transformer load (12 values/h)

The throughput for a heavy load in the network has the following pattern:

- cyclic meter reading for all meters
- sporadic metering requests from operators in parallel (10 requests/h)
- sporadic controls to SCADA in parallel (10 controls/h)
- sporadic alarms from SCADA in parallel (40 alarms/h)
- cyclical measurement of transformer load (12 values/h)

The throughput for peak load has a different pattern:

- cyclic meter reading for all meters
- sporadic metering requests from operators in parallel (20 requests/h)
- sporadic controls to SCADA in parallel (10 controls/h)
- sporadic alarms from SCADA in parallel (50 alarms/h)
- Cyclical measurement of transformer load (12 values/h)

6.4. Exemplary requirements from users

This section shows exemplary requirements of users with respect to AMR/AMM as a basis for estimations of the required throughput given in section 3.2.3.5:

- (Heitzmann, 2009):
    - 150 meters on average per data concentrator
    - Around 3,5 million meters (all media)
    - Around 20k data concentrators
    - Data acquisition for AMR:
        - at least once per day
        - resolution of at least once per 60 min.

- [RWE]:
    - 200 metering points (MUC) on average per data concentrator (max. ca. 5 meters per metering point/MUC, max. ca. 1000 MUCs per concentrator (ann.: an amount of ca. 500 is a reasonable value for this)
    - Around 8 million meters / meter points ?(all media)
    - Around 20k data concentrators
    - Data acquisition for AMR:
        - Daily value
        - Hourly value (in some cases)
- Vattenfall:
    - A subsystem on one transformer station contains max. 300 smart meters on one concentrator
    - Max. interval: 96 data packages per day and meter
    - Min. every 15 minutes all electricity meters have to be read out
    - Request on response time: max. 30 sec. for control signals
    - Data string AMR: date | time | ID | OBIS | Value | signature
    - Net data volume: 2 kByte per meter ≈ 600 kByte/15 min (AMR)
    - Data string for control signals: SML-Protocol Description
    - Net data volume for control signals: 500 Bytes
        - SML overhead, e.g.: SML_Request, SML_open, SML_Data, SML_status, SML_Close, SML_Response
        - examples for further commands: set MUC-C RTC, remote switching in the customer station, ...)
- Future applications using time- and load-variable tariffs may require to provide data to the customer in shorter time intervals (in the range of minutes) instead of the initial 60minutes-intervals.

6.5. Economic Background Information

6.5.1. European penalties for supply breaks

The following table shows European penalties for supply breaks in electrical power per 1 hour:

Connection	Customer type	Compensation
U < 1kV	Household	EUR 35
1kV ≤ U < 25kV	Small Industry	EUR 900
U ≥ 25kV	Large Industry	EUR 90.000

Table 28: European penalties for supply breaks

6.5.2. Market impact of DLC product related legislation and standardisation

Scope: The DLC market is heavily subjective to applicable EU 27 legislation and regulation, therefore a summary of the most important elements is described hereafter.

DIRECTIVE 2009/72/EC concerning common rules for the internal market in electricity

Most relevant articles are:

Article 12 (d) managing electricity flows on the system, taking into account exchanges with other interconnected systems. To that end, the transmission system operator shall be responsible for ensuring a secure, reliable and efficient electricity system and, I n that context, for ensuring the availability of all necessary ancillary services, including those provided by demand response, insofar as such availability is independent from any other transmission system with which its system is interconnected;

Article 12 (e) providing to the operator of any other system with which its system is interconnected sufficient information to ensure the secure and efficient operation, coordinated development and interoperability of the interconnected system;

Article 16 (1) Without prejudice to Article 30 or any other legal duty to disclose information, each transmission system operator and each transmission system owner shall preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its activities, and shall prevent information about its own activities which may be commercially advantageous from being disclosed in a discriminatory manner. In particular it shall not disclose any commercially sensitive information to there remaining parts of the undertaking, unless this is necessary for carrying out a business transaction. In order to ensure the full respect of the rules on information unbundling, Member States shall ensure that the transmission system owner and the remaining part of the undertaking do not use joint services, such as joint legal services, apart from purely administrative or IT functions.

ANNEX I MEASURES ON CONSUMER PROTECTION

Member States shall ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the electricity supply market. The implementation of those metering systems may be subject to an economic assessment of all the long-term costs and benefits to the market and the individual consumer or which form of intelligent metering is economically reasonable and cost-effective and which timeframe is feasible for their distribution.

Such assessment shall take place by 3 September 2012.

Subject to that assessment, Member States or any competent authority they designate shall prepare a timetable with a target of up to 10 years for the implementation of intelligent metering systems. Where roll-out of smart meters is assessed positively, at least 80 % of consumers shall be equipped with intelligent metering systems by 2020.

The Member States, or any competent authority they designate, shall ensure the interoperability of those metering systems to be implemented within their territories and shall have due regard to the use of appropriate standards and best practice and the importance of the development of the internal market in electricity.

DIRECTIVE 2006/32/EC on on energy end-use efficiency and Energy Services also referred as ESD Directive

Most relevant articles are:

Article 10 Energy efficient tariffs and other regulations for net bound energy

Member States shall ensure the removal of those incentives in transmission and distribution tariffs that unnecessarily increase the volume of distributed or transmitted energy.

Member States may permit components of schemes and tariff structures with a social aim, provided that any disruptive effects on the transmission and distribution system are kept to

the minimum necessary and are not disproportionate to the social aim.

Article 13 Metering and informative billing of energy consumption

1. Member States shall ensure that, in so far as it is technically possible, financially reasonable and proportionate in relation to the potential energy savings, final customers for electricity, natural gas, district heating and/or cooling and domestic hot water are provided with competitively priced individual meters that accurately reflect the final customer's actual energy consumption and that provide information on actual time of use.

When an existing meter is replaced, such competitively priced individual meters shall always be provided, unless this is technically impossible or not cost-effective in relation to the

estimated potential savings in the long term. When a new connection is made in a new building or a building undergoes major renovations, as set out in Directive 2002/91/EC, such

competitively priced individual meters shall always be provided.

2. Member States shall ensure that, where appropriate, billing performed by energy distributors, distribution system operators and retail energy sales companies is based on actual energy consumption, and is presented in clear and understandable

terms. Appropriate information shall be made available with the bill to provide final customers with a comprehensive account of current energy costs. Billing on the basis of actual consumption shall be performed frequently enough to enable customers to regulate their own energy consumption.

DIRECTIVE 2009/125/EC on establishing a framework for the setting of ecodesign requirements for energy-related products

The Ecodesign Directive provides with consistent EU-wide rules for improving the environmental performance of energy related products (ERPs) through ecodesign . The Ecodesign directive does not set binding requirements on products by itself: it provides a framework (rules and criteria) for setting such requirements through implementing measures.

Energy related products (the use of which has an impact on energy consumption) account for a large proportion of the energy consumption in the EU and include:

- energy-using products (EUPs), which use, generate, transfer or measure energy (e.g. electricity, gas, fossil fuel), including consumer goods such as boilers, water heaters, computers, televisions, and industrial products such as transformers, industrial fans and industrial furnaces.
- other energy related products (ERPs) which do not necessarily use energy but have an impact on energy and can therefore contribute to saving energy, such as windows, insulation material or bathroom devices (e.g. shower heads, taps).

An example of an implementing measure is COMMISSION REGULATION (EC) No 1275/2008 with regard to ecodesign requirements for standby and off mode electric power consumption of electrical and electronic household and office equipment.

It cannot be excluded that sooner or later AMI including DLC could be reviewed and subjected to implementing measures within this framework.

Directive 2004/22/EC on measuring instruments (MID)

This concerns full harmonization of utility meters. Essential Requirements (Allowable Errors, climatic/mechanical/electromagnetic environments, reproducibility,…..) for the measuring instruments are described in Annex 1 of the directive. Specific Requirements for active electrical energy meters are defined is Annex MI-003.

Most relevant articles are:

Article 7 Conformity marking

(2) Member States shall take all appropriate measures to ensure that measuring instruments be placed on the market and/or put into use only if they satisfy the requirements of this Directive.

Article 13 Harmonised standards and normative documents

Member States shall presume conformity with the essential requirements referred to in Annex I and in the relevant instrument-specific Annexes in respect of a measuring instrument that complies with the elements of the national standards implementing the European harmonised standard for that measuring instrument that correspond to those elements of this European harmonised standard the references in respect of which have been published in the Official Journal of the European Union, C series.

…

European standardisation requests or mandates

Standardisation requests (mandates) are the mechanism by which the Commission requests the European Standards Organisations (ESOs) to develop and adopt European standards in support of European policies and legislation.

Most relevant ongoing mandates are:

- The Standardization mandate M/441 (available here), issued on 12th March 2009 by the European Commission to CEN, CENELEC and ETSI, in the field of measuring instruments for the development of an open architecture for utility meters involving communication protocols enabling interoperability, is a major development in shaping the future European standards for smart metering and Advanced Metering Infrastructure.
- **Other?**

General background information on European and International standardization bodies

EN/CENELEC internal regulations define a standard as a document, established by consensus and approved by a recognized body that provides, for common and repeated use, rules, guidelines or characteristics for activities or their results, aimed at the achievement of the optimum degree of order in a given context. Standards should be based on consolidated results of science, technology and experience, and aimed at the promotion of optimum community benefits. The European EN standards are documents that have been ratified by one of the three European standards organizations, CEN, CENELEC or ETSI.

In addition to “official” standards, there may be other sector specific procedures for product testing, which could be considered as standards when they have been recognized both by the sender and the receiver, that is, when they are using the same parameters or standards.

Following the EU’s ‘New Approach’, any product-oriented legislation should preferably refer to harmonized (EN) test standards in order to verify the compliance with set measures. The referenced test standard should be accurate, reproducible and cost-effective, and model as well as possible the real-life performance. If no suitable test standard exists, they need to be developed (possibly based on existing sector specific procedures) for the relevant parameters in the view of implementing measures.

In technical use, a standard is a concrete example of an item or a specification against which all others may be measured or tested.

EN standards are equivalent to IEC standards (EN 6xxxx –series of standards). Nevertheless it is also possible to have CENELEC and EU27 national standards that are not derived from IEC (e.g. EN 50xxxx). IEC is an acronym for the International Electro technical Commission

In the US and some other countries standards are developed within the IEEE. IEEE is an acronym for the Institute of Electrical and Electronics Engineers. IEEE are not de facto equivalent to IEC standards, they are developed in parallel.

Please note that it is also possible to have national standards in Europe as far as they do not conflict with the harmonized standards.

To be completed.

Maybe a list of all applicable standards is needed somewhere in Task 1.3??

6.5.3. Current smart metering status in EU as reported by European Regulators' Group for Electricity and Gas

See available document 'Status Review on Regulatory Aspects of Smart Metering (Electricity and Gas) as of May 2009'[13].

6.5.4. Generic cost-benefit parameters for impact assessment

Scope: Several countries are undertaking economic assessments about the introduction of AMI in line with Directive 2009/72/EC. DLC is an essential component of the AMI roll out procedure. Economic assessments most often include a cost-benefit analysis and the generic parameters are described hereafter (see referred data sources hereafter). Finally those parameters will be linked to the DLC Business-model (Task 4.4) and first screening related to the scenario selection and economic boundary conditions (Task 2.1). These parameters have boundaries or limits that costumers are prepared to pay for depending on their valuation of service, see tables hereafter. Typical market parameters are included in a later section.

Data sources: Senternovem (2005)[14], VREG (2007)[15] or ESAT (2008)[16], domestic DSM see www.smart-a.org, , REMODECE IEE project, Sustainable industrial policy study on distribution and power transformers (www.ecotransformer.org), VDN requirements[17], ZVE[18], *educated guess for missing parameters or modified parameters*

Parameter overview:

Parameter	**Value**	**Uncertainty**	
		Min.	**Max.**
Economic parameters related to AMM/AMR **(source: Senternovem study, *italic parameters were changed*)**			
Costs of standard (dumb) electricity meter (E-meter)	€ 20	15	25

13 http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_ERGEG_PAPERS/Customers/Tab/E09-RMF-17-03_SmartMetering-SR_19-Oct-09.pdf

14 Senternovem (2005): 'Recommendation Implementing smart metering infrastructure at small-scale customers', October 2005, Senternovem report 4150, FAS No. 1-2893.

15 VREG (2007): 'Studie communicatiemiddelen voor slimme meters (VREG 2006/0192)', Geert Deconinck et Al., May 2007, www.vreg.be

16 ESAT (2009): Deconinck, B. Decroix, Smart Metering Tariff Schemes Combined with. Distributed Energy Resources, CRIS, Linköping, Sweden, 2009 (www.slimmemeters.be)

17 : http://download.hager.com/Hager.de/e-volution/files_download/wissen/Lastenh_101.pdf

18 http://www.enbw.com/content/de/partner/_media/pdf/eHZ-Technologie/2007090486965696ZVE_07_22_Haushaltszaehler.pdf

Costs of smart E-meter (excl. DLC component)	*€ 75*	*40*	*200*
Costs of standard (dumb) gas meter (G-meter)	€ 30	25	35
Costs of smart G-meter	€ 50	35	60
Life span of dumb E-meters	30 years	20	35
Life span of dumb G-meters	30 years	25	35
Life span of smart E-meters	15 years	10	*20*
Life span of smart G-meters	30 years	25	35
Price increase of gas, electricity, CO_2 per year	0%	0	*5%*
Residual value of existing E-meter	€ 0	0	0
Residual value of existing G-meter	€ 0	0	0
Time required for E-meter installation in household	0.5 hours	0.33	*0.75*
Time required for G-meter installation in household	0.5 hours	0.33	*0.75*
Percentage of service provider switches per year E	5%	3	6
Percentage of service provider switches per year G	2%	1	3
Reduction of E-price due to easier switch	0.0025 euro/kW_h	0.0010	0.0040
Reduction of G-price due to easier switch	0.0050 euro/m3	0.0020	0.0080
Reduced amount of telephone calls about meter readings E	50%	25	75
Reduced amount of telephone calls about meter readings G	50%	25	75
Reduction in fraud due to smart E-meters	50%	25	75
Cost per hour for an installer	€ 50 per hour	40	60
Cost per call hour for the Call Centre	€ 40 per hour	30	50
Cost per hour of lost time household	€ 7.50 per hour	0	7.50
Cost per hour for the administration	€ 50 per hour	40	60
Cost per hour for a meter reader	€ 50 per hour	40	60
Annual cost of wireless modem per household	€ 20	8	60
Savings on E due to feedback	2%	1	6
Savings on G due to feedback	2%	0	4
Increase in standing charges for smart E-meter	€ 0	0	0
Increase in standing charges for smart G-meter	€ 0	0	0
Percentage of households with paper invoice	50%	20	80
Collection / Disconnection Charges per one time	€ 100	50	200

Economic parameters for residential load management **(source www.smart-a.org *italic parameters were changed or added)***			
Value of shiftable load (moderate scenario) (€/(kW.annum))	€ 45	€ 20	€ 90
Average Wattage for Heating (heat pump?) (kW)	1.68	*0.4*	*2*
Average Wattage for Electical car (assumed 5KWh per day) (kW)	0.2	*0.2*	*0.8*
Average Wattage for smart appliances (washing, drying, refrigerator)(kW)	0.75	0.03	0.15
Specific economic DLC parameters **(added in this study)**			
Cost of DLC component for product integration (e.g. add on for AMR)	€ 25	20	50
Cost of DLC device in stand alone app. (e.g. acces point)	€ 100	50	200
Cost of MV coupling device	TBD		
DLC modem component failure rate at minimum life time of 10 years	2%	0.1%	3%
DLC modem component premature failure rate before 1 years	0.20%	0.10%	0.30%
Average DLC modem component power energy consumption	0.75W	0.5	1.5
Initial set up cost for DLC system	TBD Euro		
Set up time for DLC system	3 months	2	12
Street lighting economic parameters **(source: www.eup4light.net)**			
Energy saving per street lamp due to dimming	30%	10	50
Street lamp wattage	122W	60	450
Average operational hours per year	4000 h	2000	4000
Savings per lamp due to remote maintenance	0.05 hour	0	0.15
Grid scada economic parameters **(added in this study)**			
Saving per HV/MV substation due to SCADA	*0.33 hour*	*0*	*0.5*
Saving per HV/MV substation due to video surveillance	*0.33 hour*	*0*	*0.5*
Market size quantification parameters (EU27) **(source: Eurostat, www.ecotransformer.org)**			
EU27 habitants	501000000	NA	NA
Average size of a household in habitants	2.40	NA	NA
New installations or stock growth for meters	1%	0.5%	2%
Legally required meter replacement for callibration check vs stock	2%	1%	2.5%
Average street lighting poles per capita	0.12	0.11	0.2
Typical residential and light commercial electricity price per kWh	0.16	0.06	0.25

Typical annual electricity consumption per household (EU27)	3800 kWh	1500	15000
Total stock of distribution transformers (MV/LV)	4459000	NA	NA
Total stock of substations HV/MV	75000	NA	NA

Table 29: Generic cost-benefit parameters for impact assessment

7. Appendix III Distribution Line Carrier Applications Areas

This annex is based on a section of the internal DLC+VIT4IP report "State of the Art Analysis".

There are basically three keys areas where DLC systems are utilized; these areas are: home automation, intelligent metering management and intelligent power management. In the last quarter of 2005, a questionnaire concerning technology interest and use was carried out. The questionnaire was targeted at active and assocaite members of Cigré SC D2, as well as to several manufacturers. Twenty responses were received, 85% of which are Utilities, 15% Manufacturers, 20% from Africa, 5% American, 5% from Asia, and 70% European. Figure 7:1presents the results of the ratings as stated by each of the respondents (Cigre wgp D2.21, 2008). From this graph, it is obvious that there is a high interest in all the application areas, particularly in the AMR. In the following, the three DLC areas shall be discussed in detail.

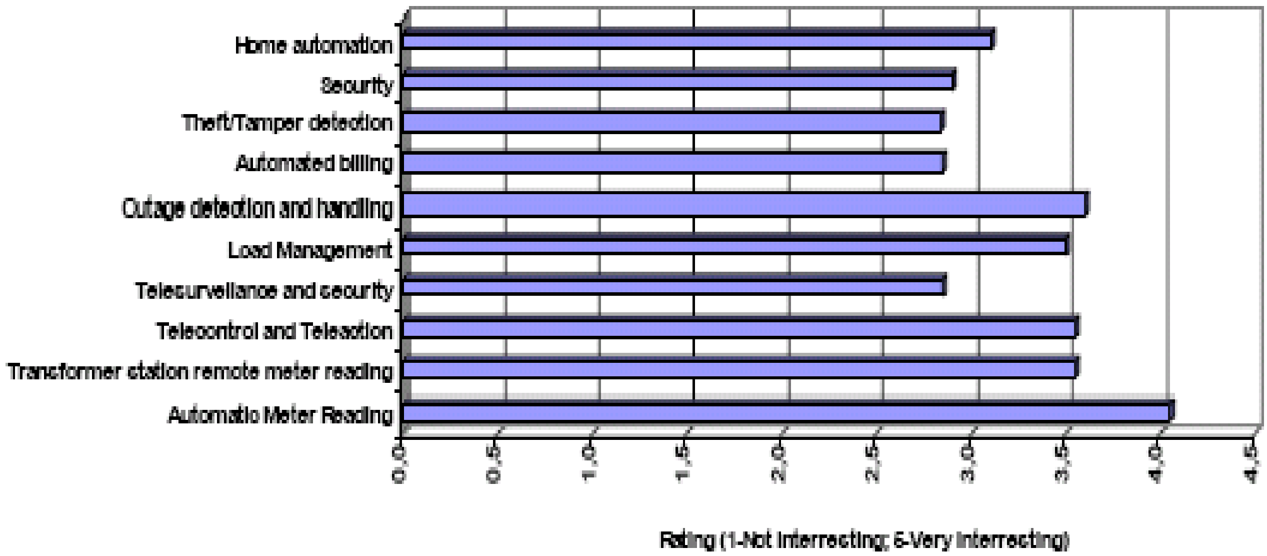

Figure 7:1 Possible Applications for xPLC

7.1. Home Automation

A Home Area Network or a home grid brings some of the smart grid capabilities into houses. A smart home or building is a home or building that is equipped with special structured wiring and devices to enable remote monitoring, controlling or programming of an array of automated home electronic devices. The field of home automation is expanding rapidly as electronic technologies converge. The home network encompasses communications, entertainment, security, convenience, and information systems. The control or monitoring signals from appliances, and related fittings or basic services is an aim of home automation.

The data transmission could be achieved via different mediums in a smart home; Wireless (Wi-Fi) networks would work well for data distribution in the home, although such high bandwidth is not necessarily required. Power Line – using the home's existing electrical outlets is a promising technology for home automation. This technology works by giving compatible devices its own address, and then communicates commands through the system. Its applications include appliances, lighting, and security. Radio Signals - Aside from the traditional devices that the power line can control, the radio signals enable you to control communications systems and your home theatre system. Emerging technologies such as Z-Wave use radio signal technology. Structured Wiring- using CAT5e or RG6 cables, although structured wiring is believed to be the most robust option, it is only possible if building a new home or undertaking an extensive home renovation. Recently, Home grid forum by promoting ITU G.hn standard developed a worldwide standard using a unified MAC/PHY for coaxial, phone line and powerline networking which enable operators to deploy home networks regardless of wire type.

Smart appliances can access the smart grid power source to optimize energy use at opportune times of the day. For example, power will only be supplied to the coffee maker in the morning and the washing machine at night. Smart appliances have the ability to communicate with other appliances in the neighbourhood and nearby on the smart grid to regulate and optimize energy use from a community level.

State-of-the-art domestic appliances can not only benefit us with energy efficiency, they can also offer a range of options for load-shifting. This can include delaying the start of washing or dishwashing cycles, interruptions of the operation of appliances, or the use of refrigerators and freezers for temporarily storing energy in order to avoid operation of the compressor during peak times. Although the energy consumption and load of a single appliance is negligible compared to the challenge of managing regional distribution networks and national electricity systems, a study shows that the impact of a coordinated smart operation of millions of domestic appliances can be significant (Smart-A , 2009). A list of potential smart appliances which used for this study is shown in Table **7.1**. Most of other electricity consuming devices in private households are typically used by consumers "on demand" and thus do not allow for much load shifting, such as computers, audio and video sets and lighting.

Table 7.1: Domestic appliances selected for the Smart-A project

	AC	Air Conditioner
	CP	Heating Circulation Pump
	DW	Dishwasher
	EH	Electric Storage Heating
	FR	Freezer
	OS	Oven & Stove
	RF	Refrigerator
	TD	Tumble Dryer
	WH	Electric Water Heater
	WM	Washing Machine

Based on these assumptions, a study in (Smart-A , 2009) applied the economic values of Smart Appliances in different generic regions to the 29 European countries. For the purpose of this study, two options for load shifting have been taken into account: Smart Timing of appliance cycles, and Interruption of appliance cycles. Estimate of the gross benefit per kW of controllable load that the introduction of Smart Appliances could bring about by the year 2025 are shown in Figure 7:3 and the CO2 saving resulted by using smart appliances is depicted in Figure 7:2 . These estimates are rough in the sense that generation flexibility assessment of the countries are not feasible in detail.

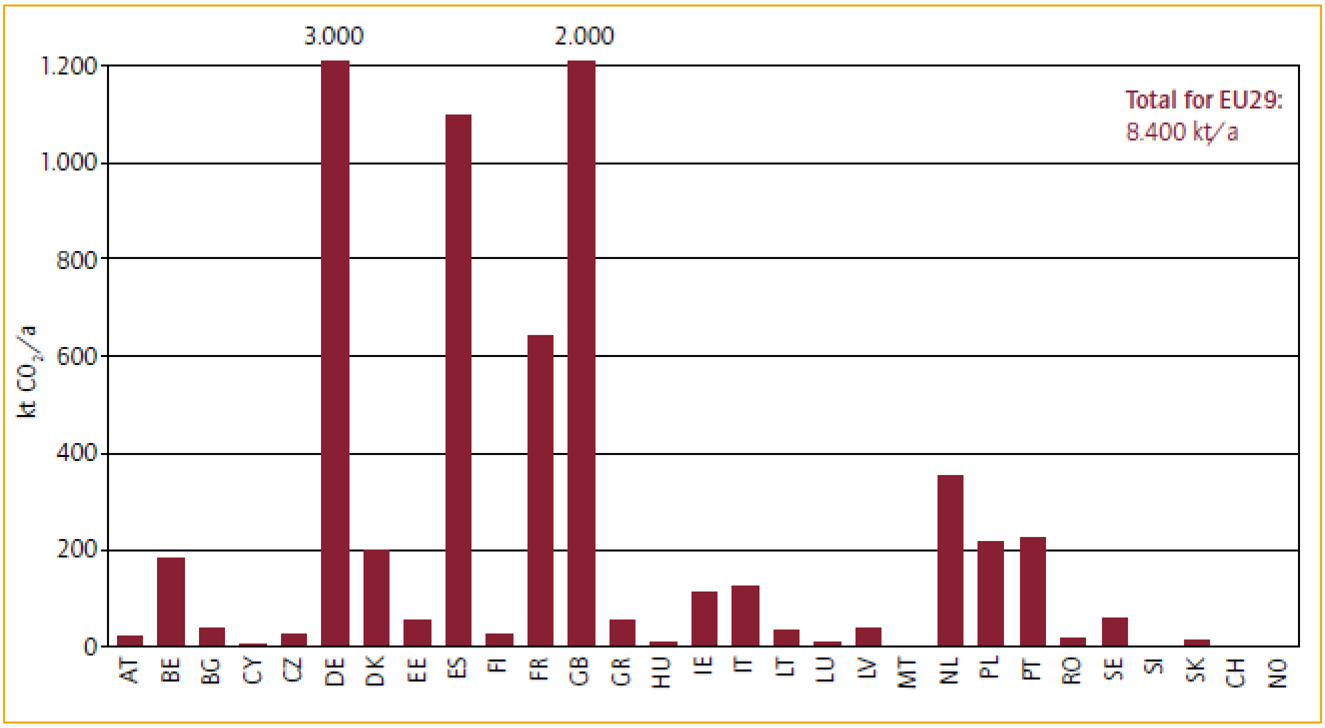

Figure 7:2: Estimated maximum annual CO_2 savings through Smart Appliances (year 2025)

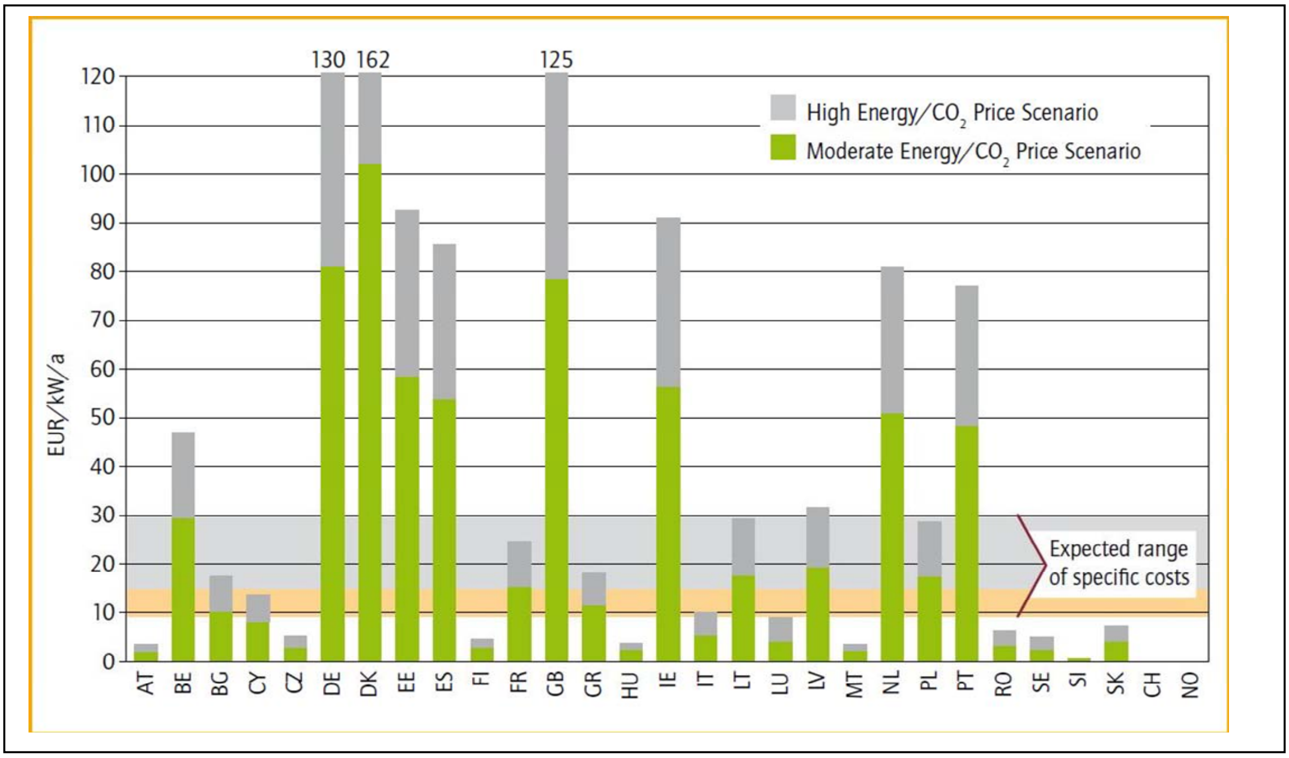

Figure 7:3: Estimated annual gross economic benefits of Smart Appliances per kW controllable load (in year 2025)(Smart-A , 2009)

Home automation systems can be broken down into four primary functions. Depending on the system's size and complexity, it will be able to control one or more of these functions: Comfort, Efficiency, Security, and Safety.

7.1.1. Comfort

Most home comfort can be achieved by using HVAC (Heating, Ventilating and Air Conditioning) systems (AllHVACInfo, 2010). Through HVAC systems, for example, the temperature of each room can be adjusted for particular activities. Water temperature can also be controlled for showers and baths to set up desired value for different users. Through meters of humidity and carbon dioxide good indoor air quality (IAQ) can be assure.

Lighting control also provides comfort by automatic toggle lights, dim light and by setting up lighting levels depending on chronological time (time of day) or astronomical time (sunrise/sunset). Technologies like Insteon and DALI are used specially for lighting control. Their speeds are in the range from 1.2 kbps up to 13.165 kbps on peak load.

7.1.2. Efficiency

Nowadays energy efficiency is an important concept, due to global warming and high energy prices. Minimize energy consumption is a way to improve consumption efficiency. This can be achieved by using different appliances and disconnecting them from the power network in case of exceeding predefined limit of consumption or by using smart metering capabilities, which allow utilities to communicate with the house and power down appliances during peak loads on the network.

7.1.3. Security

Home automation provides home security by applications like: one key for all doors, control and authorized entry, visual and motion detectors. Speakerphones with entry codes, appropriate card readers or key pads for visitors are also used to ensure the home security. Last but not least, security lighting can imitate the presence of people in the house to ensure security.

7.1.4. Safety

Safety home automation systems are smoke and fire alarm systems, which notify the user about fire or smoke appearing. These systems may also prevent the fire danger by automatic disconnecting appliances from the power grid.

Other safety applications are panic buttons at strategic locations, these buttons are necessary for disabled and ill people to provide them urgent help. Similarly remote door opening is useful for old and disabled people; it can also be combined with voice control function.

7.2. Intelligent Metering Management

Remote metering is a group of technologies that allows remote measurement and reporting of information. Although the term commonly refers to wireless data transfer mechanisms (radio or infrared systems), it also encompasses data transferred over other media; such as a telephone or computer network, optical link, power line or other wired communications.

7.2.1. Automatic Meter Reading (AMR)

AMR ia a remote reading system based on an advanced technology that permits utilities to read electronic meters over long distances. Through AMR, the energy consumption can be read on an annual, monthly, weekly, daily or on an hourly basis.

Consumption and status data, such as time stamps, are through various connection media being transmitted to a central system for billing and analysis. The automatic data collection enables billing based on real time consumption as opposed to an estimated consumption.

AMR systems consist of a Host Central Station (HCS), Data Concentrator Units (DCU) and Meter Interfacing Units (MIU). Each HCS, while working independently, can also be integrated with an existing corporate information management system through software interface.

7.2.2. Smart Meter

A smart meter is an advanced meter (usually an electrical meter) that identifies consumption in more detail than a conventional meter; and optionally, but generally, communicates that information via some network back to the local utility for monitoring and billing purposes (telemetering).

Smart meter often refers to an electrical meter, but it can increasingly also mean a device measuring natural gas or water consumption.

Similar meters, usually referred to as interval or time-of-use meters, have existed for years, but Smart Meters usually involve a different technology mix, such as real-time or near real-time sensors, power outage notification, and power quality monitoring. These additional features are more than simple automated meter reading (AMR). They are similar in many respects to advanced metering infrastructure (AMI) meters.

7.2.3. Automated/Advanced Multi-Metering Infrastructure (AMI)

AMI refers to systems that measure, read and analyse energy consumption. These systems are also able to read electricity, gas, heat and water meters remotely. AMI systems can be defined a san extension of the simpler AMR-system. The AMI always communicates two-way and comprises the whole range of metering devices, software, communication media, and data management systems.

The concept of Automatic Meter Reading (AMR) is rapidly evolving towards smart multi-metering or multi-functional Advanced Multi-Metering Infrastructure (AMI). A future AMI scenario will allow energy service companies to provide demand management capabilities while also establishing new services that create value for energy consumers, network operators, metering operators and retailers. These services will at least include automatic meter reading, flexible and remotely programmable power control, remote (re)connection and disconnection and flexible tariff management.

7.2.4. Automated Meter Management (AMM) or Smart Metering

AMM is another expansion of remote system that includes possibility of performing technical measurements and functions and carrying out customer-oriented services via the system. The question is not anymore how to get the data, but how to manage them and how to get the most information out of them. This in fact the core of the smart meter: it enables a sensible and economical viable allocation of the resources from data collection to analysing data.

7.2.5. Demand Side Management (DSM)

Demand-Side Management is customer response changing energy use in response to market factors including:

- Conservation – Use less across many hours.
- Demand Response – Use less when prices and/or production costs are high.
- Load management -- Shifting demand from high price to low / price periods and peack load management.

“DSM” includes energy efficiency (EE) and demand response (DR):

– Energy conservation investments in EE to reduce bills (many options).

– Event-based load response tied to operator notification:

- Traditional large customer interruptible programs tied to reliability triggers.
- Direct load control programs (water heaters or AC units, even some C&I loads)

– Event-based price response to operator notification:

- Time of use pricing with event-based critical peak pricing.
- Day-Ahead hourly pricing on called “event days.”

– Non-event based price response (independent of any operator):

- TOU rates every day (programs becoming more targeted and granular)
- Day-Ahead hourly pricing every day
- Real-time pricing (actual daily markets)

– System-reliability based DR – interruptible customers tied to notification.

– Price-based DR - customers make choices in response to price signals.

7.2.6. Power Quality Monitoring System (PQMS)

Power quality (PQ) is the generic name given to a range of disturbances on the electrical network. Each PQ disturbance has a defining characteristic wave shape. By identifying the type or types of disturbances, the cause and possible solution can be found.

The Power Quality Monitoring System objective consists in determining the quality of power and the behavior of the electrical system globally. The PQMS monitors the quality of supply of all of its high and medium voltage costumers. The PQMS monitors both the voltages and the currents together with other variables and then sends this data to a central computer which then manages and controls the data.

7.3. Intelligent Power Management

Intelligent Power Management (IPM) optimizes the distribution and use of electrical power. While the installation of IPM involves up-front cost and ongoing maintenance, the technology can save money in the long term as a result of reduced electric bills, reduced downtime and reduced total energy consumption. The key component of IPM is Distribution Automation (See

Figure 7:4) and it's latest derivatives .

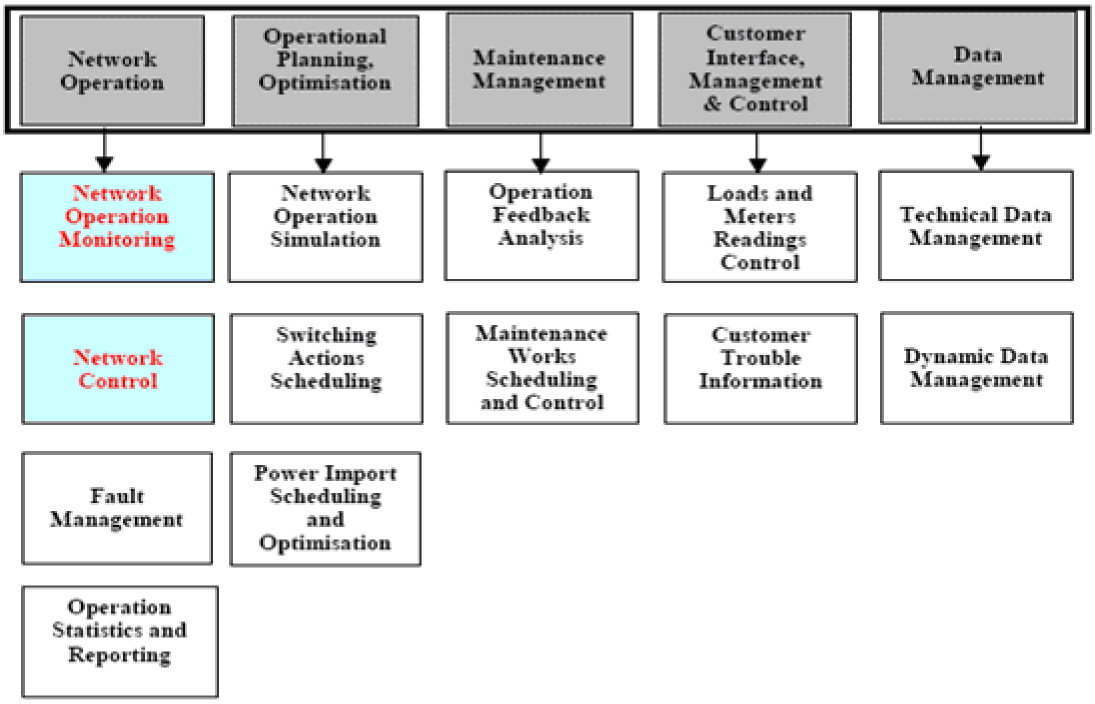

Figure 7:4 Distribution Automation – main functions

7.3.1. Smart Grid

The term "smart grid" refers to an electricity transmission and distribution system that incorporates elements of traditional and cutting-edge power engineering, sophisticated sensing and monitoring technology, information technology, and communications to provide better grid performance and to support a wide array of additional services to consumers. A smart grid is not defined by what technologies it incorporates, but rather by what it can do. The key attributes of the 21st century grid include the following:

- The grid will be "self-healing." Sophisticated grid monitors and controls will anticipate and instantly respond to system problems in order to avoid or mitigate power outages and power quality problems.

- The grid will be more secure from physical and cyber threats. Deployment of new technology will allow better identification and response to manmade or natural disruptions.

- The grid will support widespread use of distributed generation. Standardized power and communications interfaces will allow customers to interconnect fuel cells, renewable generation, and other distributed generation on a simple

"plug and play" basis.

- The grid will enable consumers to better control the appliances and equipment in their homes and businesses. The grid will interconnect with energy management systems in smart buildings to enable customers to manage their

energy use and reduce their energy costs.

- The grid will achieve greater throughput, thus lowering power costs. Grid upgrades that increase the throughput of the transmission grid and optimize power flows will reduce waste and maximize use of the lowest-cost generation resources. Better harmonization of the distribution and local load servicing functions with interregional energy flows and transmission traffic will also improve utilization of the existing system assets.

7.3.2. Self-Healing Grid

The SHG function comprises a set of computing applications for information gathering, modeling, decision-making, and controlling actions. These applications reside in central and/or in widely distributed systems, such as relay protection, remedial automation schemes (RAS), local controllers, and other distributed intelligence systems. All these applications and system components operate in a coordinated manner and are adaptive to the actual situations.

The conventional methodology for emergency control is based on off-line studies for selection of the local emergency automation schemes, their locations, and their settings. Such off-line studies are usually performed for selected operating conditions based on typical cases and on previous emergencies. However, the design of remedial actions and emergency automation schemes based on previous emergencies may be ineffective for the future emergencies. In reality, the emergency situations often occur under conditions that are quite different from the study cases. With the advent of deregulation, the energy schedules are derived from financial considerations rather than strictly power operations considerations. Therefore, the types of possible contingencies increase substantially, and it would be very difficult to study with purely off-line analyses. Not only are there increased pressures from deregulation, there are new challenges imposed by the involvement of distribution systems and customers in preventing and responding to power system emergencies. For instance, with the increased number of distributed energy resource (DER) devices connected to the distribution system, distribution operations have to expand to monitor and manage (if not actually control) these DER devices. The advances of Distribution Management Systems (DMS) and Advanced Distribution Automation (ADA) make these systems available for real-time coordination of transmission and distribution operations in normal, emergency, and restorative states of the power systems.

The SHG will be supported by fast data acquisition systems (Wide Area Measurement Systems and SCADA) and will include fast simulation and decision-making applications observing wide power system areas. These wide-area applications will coordinate the behavior of distributed control systems (regional EMS, DMS, Plant EMS, RAS, and relay protection). These distributed systems and actuators will perform adequately fast under emergency and later under restorative conditions following the rules and settings preset by the upper level simulation and decision-making applications. The coordination of different systems and actuators will be accomplished in a hierarchical manner. Some directive from the upper level, e.g., from the ISO/RTO EMS will be transmitted to the regional EMS, and some commands and settings will be downloaded directly to the actuators. The regional EMS will transmit some directives to the DMS and plant EMS and some commands and settings will be directly downloaded to the actuators, which are in the corresponding areas of responsibility. Some local actuators will be integrated into distributed intelligence schemes and will communicate among themselves in a peer-to-peer manner. The rules of behavior of the distributed intelligence schemes can be preset by the upper control system.

The power system operators will be the Persons In Charge (PIC) for the performance of the entire SHG and will participate in the system setup and decision-making processes, which allow sufficient time for the operators to perform an educated action. Under emergency conditions, when fast and complex actions should be performed, the pre-armed and adaptive local and distributed applications and automatic schemes should be the main executors for the protection of equipment and prevention of blackouts.

The future control system for the self-healing grid will differ from the current approaches by implementing significantly more automated controls instead of supervisory controls by the operators and by aiming at preservation of adequate integrity of the generation-transmission-distribution-customer system instead of self-protection of equipment only.

7.3.3. Supervisory Control and Data Acquisition (SCADA)

The Data Acquisition and Control (DAC) function, used in transmission and distribution operations, comprises multiple types of mechanisms for data retrieval from field equipment and the issuing of control commands to power system equipment in the field, including among field devices, between field devices and systems located in substations, and between field devices and various systems (including, but not limited to, SCADA systems) located in DER and utility control centers and engineering/planning centers.

Objectives: The DAC function provides real-time data, statistical data, and other calculated and informational data from the power system to systems and applications that use the data. The DAC function also supports the issuing of control commands to power system equipment and the setting of parameters in IEDs and other field systems.

Rationale: Power system real-time data is source of most information required for power system operations. Control over the power system equipment can be achieved by issuing control commands and setting parameters.

The Data Acquisition and Control (DAC) function, used in transmission and distribution operations, comprises multiple types of mechanisms for data retrieval and issuing of control commands to power system equipment. These mechanisms are often used in conjunction with each other to provide the full range of DAC interactions. The DAC function, in turn, is used by other functions, such as Supervisory Control and Data Acquisition (SCADA) systems, Energy Management Systems (EMS), Protection Engineering systems, and Advanced Distribution Automation (ADA), as the means for their interactions with the power system equipment.

The SCADA product supports a wide range of industry standard and legacy protocols, including DNP 3.0, IEC-60870-5, TASE.2 ICCP, ELCOM-90 and DL-476-92. It is integrated with DMS, EMS and GMS products for real-time network analysis, and can be used in substation automation and pipeline management projects. Its features include:

- IP-based redundant front-end processors
- Supports bit-oriented synchronous and asynchronous protocols
- Large library of legacy RTU protocols available
- RDBMS-based database management facility
- Online database edits with audit trail
- Fully internationalized user interface with secure access control
- Automatic generation of substation and RTU tabular displays
- Large library of dynamic symbol objects for graphic displays
- Powerful calculated points engine
- Rich scripting language for real-time automatic process control
- Replicated real-time database for superior performance
- Historical data collection

- ODBC/SQL access
- Web-based access to SCADA data and displays

7.3.4. Distribution Management System (DMS)

The DMS product provides utilities with a comprehensive suite of applications and tools for efficient, reliable and cost-effective management of distribution networks. Its sophisticated network model supports three-phase unbalanced networks, and is the basis for all of the DMS applications. The DMS product provides an interface to most major GIS systems for initial population and online incremental updates of the network model and operating displays. The DMS applications are fully integrated with SCADA and EMS products and use a common real-time database. Most DMS applications are available in both real-time and study mode. Applications include:

- GIS interface
- Network connectivity analysis
- Feeder coloring and tracing
- Cuts, grounds and jumpers
- Load forecast
- Load estimation
- 3-phase unbalanced power flow
- Fault level analysis
- Fault detection, isolation and restoration
- Load shedding
- Loss minimization and load balancing
- Contingency load transfer
- Volt-var control
- Intelligent switching management
- Trouble call and outage management
- Work crew management
- Dispatcher training simulation

7.3.5. Advanced Distribution Automation (ADA)

The ADA Function performs a) data gathering, along with data consistency checking and correcting; b) integrity checking of the distribution power system model; c) periodic and event-driven system modeling and analysis; d) current and predictive alarming; e) contingency analysis; f) coordinated volt/var optimization: g) fault location, isolation, and service restoration; h) multi-level feeder reconfiguration; i) pre-arming of RAS and coordination of emergency actions in distribution; j) pre-arming of restoration schemes and coordination of restorative actions in distribution, and k) logging and reporting. These processes are performed through direct interfaces with different databases and systems, (EMS, OMS, CIS, MOS, SCADA, DMS, AM/FM/GIS, AMS and WMS), comprehensive near real-time simulations of operating conditions, near real-time predictive optimization, and actual real-time control of distribution operations.

Rationale: By meeting its objectives in near-real time, the Function makes a significant contribution to improving the power system operations through automation, which cannot be achieved using existing operational methods.

Status: The methodology and specification of the Function for current power system conditions have been developed, and prototype (pilot) and system-wide project in several North-American utilities have been implemented by Utility Consulting International and its client utilities prior to IntelliGrid Architecture project.

7.3.6. Relay Protection Reconfiguration Function

No fault calculations are needed in this application, if the distribution system is radial without significant DER.

With DERs in distribution, the situation is much more complex, especially when supporting the fuse-saving protection policy. There are a variety of relationships between fault currents through the protective devices and through fuses. The room for adjustment of the settings of the protective devices is limited. Hence, it is possible, that under some conditions, the coordination for the fuse saving protection cannot be provided. Therefore, the relay protection coordination application should include a fault calculation routine determining probable fault currents through the protective devices and through the fuses. The range of these fault currents should be compared with the corresponding settings, and a decision about the coordination should be made. If the coordination with existing settings cannot be provided, and changes of settings of the protective devices are possible, then the recommended changes should be implemented. The assumption here is that the future protective devices will be available for remote change of their settings.

Another consideration in regards to fuse saving protection is the disconnection of the DER before the reclosing to avoid asynchronous connections. If the interruption of DER services for fuse saving purposes is unacceptable (contractual agreement between DER owner and DISCO), then the fuse saving protection cannot be implemented. The input data for the application should include the DER characteristics needed for calculations of the fault currents (different types of DER will have different characteristics) and the relevant contractual conditions, if any.

The situation is different when the coordination of several protective devices along the feeder should be coordinated, and there are DERs connected to the circuits between the protective devices. In this case, the fault current through the protective device downstream from the DER will be greater than the fault current upstream from the DER, and it is easier to provide coordination. But, if the DER disconnects before the fault is cleared due to low voltage, then the margin for coordination becomes smaller. This relationship between the residual voltage at the DER PCC, timing of the relay protection, and relay protection setting should be taken into account in the relay protection coordination application.

7.3.7. Multi-level Feeder Reconfiguration Function

This application recommends an optimal selection of feeder(s) connectivity for different objectives. It supports three modes of operation:

1. Closed-loop mode, in which the application is initiated by the Fault Location, Isolation and Service Restoration application, unable to restore service by simple (one-level) load transfer, to

determine a switching order for the remotely-controlled switching devices to restore service to the non-faulted sections by using multi-level load transfers. .

2. Advisory mode, in which the application is initiated by SCADA alarms triggered by overloads of substation transformer, segments of distribution circuits, or by DOMA detecting an overload, or by operator who would indicate the objective and the reconfiguration area. In this mode, the application recommends a switching order to the operator.
3. Study mode, in which the application is initiated and the conditions are defined by the user.

The application performs a multi-level feeder reconfiguration to meet one of the following objectives:

- Optimally restore service to customers utilizing multiple alternative sources. The application meets this objective by operating as part of Fault Location, Isolation and Service Restoration.
- Optimally unload an overloaded segment. This objective is pursued if the application is triggered by the overload alarm from SCADA, or from the Distribution Operation Modeling and Analysis, or from Contingency analysis. These alarms are generated by overloads of substation transformer or segments of distribution circuits, or by operator demand.
- Minimize losses
- Minimize exposure to faults
- Equalize voltages

The last three objectives are selected by engineer/planner.

The feeder reconfiguration process is a multi-objective function with a very large number of variables. Theoretically, the number of possible combinations to consider during the search of the best solution is equal 2n, where n is the number of switching devices in the interconnected circuits. With DERs connected to the distribution circuits, the circuit configuration solution may be different. Just by adding the two states of DER: ON or OFF, the number of combinations for searching the configuration solution increases to 2n+m, where m is the number of DERs connected to the subject circuit. Different modes of operation and different load schedules of DER can also change the solution. Hence, the number of combination may increase even more. The nominal optimal configuration is typically selected for a long-term interval (season, year). If the solutions are different with DERs ON from those with DERs OFF, then the application should take into account the probable schedules of the DERs during the entire time interval for which the configuration solution is sought and find a configuration which is the best for this time interval. The application should be capable of recommending smaller time intervals with different circuit boundaries.

When the reconfiguration solution implies the participation of DER devices, and the circuits can be overloaded if the DER devices are disconnected, then an additional condition that the DER devices are always available when needed by the Area EPS should be present. In this case the maintenance of DER devices will lead to temporary change of configuration, and an outage of DER at heavy-load times is a contingency. Hence, DERs introduce additional opportunities and additional constraints to the configuration and to the migration from one configuration to another.

When the distribution circuits are reconfigured, a DER may move from being electrically connected to one substation bus to being connected to another bus, and this may be unacceptable by the DER owner due to, e.g., a change of the DER capability to provide ancillary services, or due to an increase in exposure to faults. (The DER owner may have a reliability guarantee or similar agreement with DISCO, limiting the exposure to faults.) The input data describing such kind of conditions should be made available to the reconfiguration application.

Other constraints can be imposed by the transient process during switching operations while implementing the new configuration, which consist of paralleling and breaking. The change in voltage magnitude and phase angle during the switching operations will present some kind of disturbance for the DER and in some instances may be unacceptable. Such parameters as acceptable rate of voltage and angle changes may be needed for deciding whether the configuration with a DER connected to the circuit can be accomplished. In some cases, a temporary intentional islanding during the transition from one configuration to another can be included in the reconfiguration solution.

The specific of multi-level feeder reconfiguration process is that the more connectivity alternatives are available, the greater are the optimization benefits. As was mentioned above, the number of alternatives increases with the increase of the number of sectionalizing and transfer switching devices. In order to consider the maximum number of alternatives all interconnected feeders with all switching devices available for control should be included in the optimization process. The presence of DER devices in the distribution system increases the number of alternatives due to the various combinations of kW and kvar injections, possibilities of islanding, and protection schemes, and contractual agreements. The run-times of the multi-level feeder reconfiguration program ranges from seconds to hours depending on the reconfiguration objective.

The feeder reconfiguration solution will be used for different timeframes, such as:

1. For several hours after clearing a fault for service restoration to healthy sections. The solution should be found in the matter of seconds.
2. For several hours or days for voltage equalization, when there is an urgent need in load reduction via Volt, Var, and Watt control. The solution should be found in the matter of minutes.
3. For several days or weeks for load balancing during maintenance of distribution facilities. The solution should be found in the matter of seconds. The solution should be found in the matter of tens of minutes.
4. For a season or a year for minimization of customer exposure to interruptions, normal load balancing, and loss minimization. The solution should be sought during several hours.

The input data for this computing application shall include the following DER object model attributes for different reconfiguration objectives and different timeframes:

a. For minimizing exposure of the distribution system to customer interruptions, the following attributes of the DER object model (or other sources of information) will be used:
   - Rated characteristics
   - Long-term operation and maintenance schedules
   - Contractual constraints
   - Conditions for automatic islanding
b. For balancing loads of substation transformers and distribution feeders, the following attributes may be needed:
   - Rated characteristics, including the capability curves
   - Short-term operation and maintenance schedules
   - Contractual constraints

c. For equalizing voltages between feeders and substations, the following attributes should be considered:
    - Rated characteristics, including the capability curves
    - Short-term operation and maintenance schedules
    - Contractual constraints
    - P-Q-V modes of operations
    - Availability to start DER devices in Area EPS demand

d. For minimizing energy losses, in addition to the attributes mentioned above, the cost of DER operations will be needed.

7.3.8. Public Street Lighting Control and Monitoring

Public Street Lighting Control and Monitoring works basically with modems and sensors connected at the power source of the street lamp of a public lighting system. A sensor senses the current flow through the lamp, thus monitoring the operation of the street lamp. If the lamp breaks down, the modem will report the address code of the lamp report back to the monitoring station through the power cable. A repairman can then be sent immediately to the right location to check and replace the bulb.