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Peyman Jafary

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Peyman Jafary

Cyber-Security Solutions for Ensuring Smart Grid Distribution Automation Functions

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Doctoral candidate: Peyman Jafary
Laboratory of Electrical Energy Engineering
Faculty of Computing and Electrical Engineering
Tampere University of Technology
Finland

Supervisors: Sami Repo, Professor
Laboratory of Electrical Energy Engineering
Faculty of Computing and Electrical Engineering
Tampere University of Technology
Finland

Hannu Koivisto, Professor
Laboratory of Automation and Hydraulic Engineering
Faculty of Engineering Sciences
Tampere University of Technology
Finland

Pre-examiners: Chen-Ching Liu, Professor
Faculty of Electrical Engineering & Computer Science
Washington State University
United States

Matti Lehtonen, Professor
Faculty of Electrical Engineering
Aalto University
Finland

Opponents: Lars Nordström, Professor
Department of Electric Power and Energy Systems
Royal Institute of Technology (KTH)
Sweden

Matti Lehtonen, Professor
Faculty of Electrical Engineering
Aalto University
Finland

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Abstract

The future generation of the electrical network is known as the smart grid. The distribution domain of the smart grid intelligently supplies electricity to the end-users with the aid of the decentralized Distribution Automation (DA) in which intelligent control functions are distributed and accomplished via real-time communication between the DA components. Internet-based communication via the open protocols is the latest trend for decentralized DA communication. Internet communication has many benefits, but it exposes the critical infrastructure's data to cyber-security threats. Security attacks may not only make DA services unreachable but may also result in undesirable physical consequences and serious damage to the distribution network environment. Therefore, it is compulsory to protect DA communication against such attacks. There is no single model for securing DA communication. In fact, the security level depends on several factors such as application requirements, communication media, and, of course, the cost.

There are several smart grid security frameworks and standards, which are under development by different organizations. However, smart grid cyber-security field has not yet reached full maturity and, it is still in the early phase of its progress. Security protocols in IT and computer networks can be utilized to secure DA communication because industrial ICT standards have been designed in accordance with Open Systems Interconnection model. Furthermore, state-of-the-art DA concepts such as Active distribution network tend to integrate processing data into IT systems.

This dissertation addresses cyber-security issues in the following DA functions: substation automation, feeder automation, Logic Selectivity, customer automation and

Smart Metering. Real-time simulation of the distribution network along with actual automation and data networking devices are used to create hardware-in-the-loop simulation, and experiment the mentioned DA functions with the Internet communication. This communication is secured by proposing the following cyber-security solutions.

This dissertation proposes security solutions for substation automation by developing IEC61850-TLS proxy and adding OPen Connectivity Unified Architecture (OPC UA) Wrapper to Station Gateway. Secured messages by Transport Layer Security (TLS) and OPC UA security are created for protecting substation local and remote communications. Data availability is main concern that is solved by designing redundant networks.

The dissertation also proposes cyber-security solutions for feeder automation and Logic Selectivity. In feeder automation, Centralized Protection System (CPS) is proposed as the place for making Decentralized feeder automation decisions. In addition, applying IP security (IPsec) in Tunnel mode is proposed to establish a secure communication path for feeder automation messages. In Logic Selectivity, Generic Object Oriented Substation Events (GOOSE) are exchanged between the substations. First, Logic Selectivity functional characteristics are analyzed. Then, Layer 2 Tunneling over IPsec in Transport mode is proposed to create a secure communication path for exchanging GOOSE over the Internet. Next, communication impact on Logic Selectivity performance is investigated by measuring the jitter and latency in the GOOSE communication. Lastly, reliability improvement by Logic Selectivity is evaluated by calculating reliability indices.

Customer automation is the additional extension to the smart grid DA. This dissertation proposes an integration solution for the heterogeneous communication parties (TCP/IP and Controller Area Network) in Home Area Network. The developed solution applies Secure Socket Layer in order to create secured messages.

The dissertation also proposes Secondary Substation Automation Unit (SSAU) for real-time communication of low voltage data to metering database. Point-to-Point Tunneling Protocol is proposed to create a secure communication path for Smart Metering data.

The security analysis shows that the proposed security solutions provide the security requirements (Confidentiality, Integrity and Availability) for DA communication. Thus, communication is protected against security attacks and DA functions are ensured. In addition, CPS and SSAU are proposed to distribute intelligence over the substations level.

Preface

This study was carried out in the Laboratory of Electrical Energy Engineering at Tampere University of Technology during 2013-2017. The primary supervisor of this dissertation has been Prof. Sami Repo. I wish to express my deepest gratitude to Prof. Sami Repo for his unceasing support, technical supervision and guidance throughout this dissertation. Additionally, I would like to thank my co-supervisor Prof. Hannu Koivisto for his valuable comments during this study.

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Tampere, December 2017

Peyman Jafary

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List of Publications

[P1] P. Jafary, S. Repo and H. Koivisto, "Secure Integration of the Home Energy Management System to the Battery Management System in the Customer Domain of the Smart Grid", *In IEEE Power and Energy Society (PES) General Meeting*, National Harbor, MD, United States, July 2014.

[P2] P. Jafary, M. Salmenperä, S. Repo and H. Koivisto, "OPC UA security for protecting substation and control center data communication in the distribution domain of the smart grid", *In IEEE International Conference on Industrial Informatics (INDIN)*, Cambridge, United Kingdom, July 2015.

[P3] P. Jafary, S. Repo and H. Koivisto, "Secure communication of smart metering data in the smart grid secondary substation", *In IEEE Innovative Smart Grid Technologies - Asia (ISGT ASIA)*, Bangkok, Thailand, November 2015.

[P4] P. Jafary, S. Repo and H. Koivisto, "Security solutions for smart grid feeder automation data communication", *In IEEE International Conference on Industrial Technology (ICIT)*, Taipei, Taiwan, March 2016.

[P5] P. Jafary and et al, "Secure Layer 2 Tunneling Over IP for GOOSE-based Logic Selectivity", *In IEEE International Conference on Industrial Technology (ICIT)*, Toronto, Canada, March 2017.

[P6] P. Jafary, J. Seppälä, S. Repo and H. Koivisto, "Security and Reliability Analysis of a Use Case in Smart Grid Substation Automation Systems", *In IEEE International Conference on Industrial Technology (ICIT)*, Toronto, Canada, March 2017.

List of Abbreviations

AAA	Authentication, Authorization, Accounting
ADA	Advanced Distribution Automation
AES	Advance Encryption Standard
AIS	Aggregator Information System
AMI	Advanced Metering Infrastructure
AMM	Automated Meter Management
AMR	Automated Meter Reading
ANM	Active Network Management
APCI	Application Protocol Control Information
APDU	Application Protocol Data Unit
API	Application Programming Interface
ASDU	Application Service Data Unit
BMS	Battery Management System
CAN	Controller Area Network
CC	Control Center
CIA	Confidentiality, Integrity, Availability
CIM	Common Information Model
CIS	Customer Information System
COSEM	COmpanion Specification for Energy Metering
CPS	Centralized Protection System
CRC	Cyclic Redundancy Check
CYSEMOL	Cyber Security Modeling Language
DA	Distribution Automation
DAN	Doubly Attached Node
DER	Distributed Energy Resources
DG	Distributed Generation
DIC	Distribution Information Center
DLMS	Device Language Message specification
DMS	Distribution Management System
DMZ	Demilitarized Zone
DO	Data Object
DSO	Distribution System Operator
EAP	Extensible Authentication Protocol
EMS	Energy Management System
ENISA	European Network and Information Security Agency
ESP	Encapsulating Security Payload
FDIR	Fault Detection Isolation and Restoration
GIS	Geographic Information Systems

GOOSE	Generic Object Oriented Substation Event
HAN	Home Area Network
HEMS	Home Energy Management System
HMI	Human Machine Interface
HSR	High-availability Seamless Redundancy
HV	High Voltage
IE	Industrial Ethernet
IEC TC57	International Electrotechnical Commission Technical Committee 57
IED	Intelligent Electronic Device
IKE	Internet Key Exchange
IP	Internet Protocol
IPRP	IP Parallel Redundancy Protocol
IPSEC	Internet Protocol Security
ISA	International Society of Automation
ISO	International Organization for Standardization
ISP	Internet Service Provider
IT & OT	Information and Operational Technologies
L2TPv3	Layer 2 Tunneling Protocol version 3
LAN	Local Area Network
LD	Logical Device
LN	Logical Node
LRE	Link Redundancy Entity
LV	Low Voltage
MAC	Media Access Control
MDC	Meter Data Concentrator
MIS	Metering Information System
MMS	Manufacturing Message Specification
MV	Medium Voltage
NAN	Neighborhood Area Network
NIS	Network Information System
NIST	National Institute of Standards and Technology
NMT	Network Management
NTP	Network Time Protocol
OA	Object Attribute
OBIS	OBject Identification System
OPC DA	Open Platform Communications Data Access
OPC UA	OPen Connectivity Unified Architecture
OSI	Open Systems Interconnection
P2CySeMoL	Predictive, Probabilistic Cyber Security Modeling Language
PC	Personal Computer
PD	Physical Device

PDO	Process Data Objects
PPTP	Point-to-Point Tunneling Protocol
PRP	Parallel Redundancy Protocol
PS	Primary Substation
PTP	Precision Time Protocol
QoS	Quality of Service
RCT	Redundancy Control Trailer
RPDO	Receive PDO
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAN	Single Attached Node
SAS	Substation Automation Systems
SCADA	Supervisory Control and Data Acquisition
SCL	Substation Configuration Language
SDO	Service Data Objects
SFO	Special Function Objects
SNTP	Simple Network Time Protocol
SS	Secondary Substation
SSAU	Secondary Substation Automation Unit
SSL	Secure Socket Layer
SV	Sampled Values
TCP	Transmission Control Protocol
TLS	Transport Layer Security
TPDO	Transmit PDO
UDP	User Datagram Protocol
USB	Universal Serial Bus
VLAN	Virtual LAN
VPN	Virtual Private Network
WAN	Wide Area Network
WIS	Work Information System
XML	Extensible Markup Language

1 INTRODUCTION

The motivation behind the smart grid is to improve the efficiency of the electricity supply chain in several economically feasible ways such as increasing the hosting capacity for the renewable energy sources, supplying the acceptable-quality power to the customers, the utilization of the heat pumps, the smart charging of the electric vehicles and enhancing the general reliability of the grid. The distribution domain [1] of the smart grid links electricity from the transmission domain to the customer domain. Traditional distribution systems relied on a low level of automation with basic data communication capabilities. However, smart grid Distribution Automation (DA) takes advantage of the latest advances in ICT systems in order to enable efficient operation of the very much more complex distribution grid of the future. Smart grid DA attempts to create an intelligent and controllable distribution grid by deploying two-way ICT capable of transmitting real-time operational data, rather than just historical data. This results in real-time monitoring and control of the remote distribution elements, thus enabling intelligent operation of the distribution network. ICT systems provide access to the distribution network data needed for a variety of purposes such as monitoring, supervision, protection, control, condition monitoring, operational planning, maintenance and asset management.

The DA is performed at different levels [2] such as the substation level, feeder level, distribution network level, control center level and Distribution System Operator (DSO) level. Information exchange and integration are the key enablers for adding new smart grid functions to DA. ICT systems create the required interaction between the distribution network applications and the components. DA ICT systems contain a heterogeneous network of networks including automation networks, computer networks, cellular

network and wireless networks. On the one hand, employing various network types satisfies the interaction requirements for the emerging DA applications. On the other hand, DA data communication suffers from the security vulnerabilities to which all these different networks are susceptible. Data exchange in ICT systems must be secure because the overall performance of the DA is dependent on the validity of the real-time data that is transmitted over the ICT systems.

Several organizations are currently studying smart grid security requirements including DA communication security. Many of the challenges of smart grid security have already been identified by the European Network and Information Security Agency (ENISA) in [3]. The International Electrotechnical Commission Technical Committee 57 (IEC TC57) Working Group 15 particularly focuses on communication security and has developed the IEC 62351 [4] standard of the Information Security for Power System Control Operations. Furthermore, security requirements for DA applications have been generally defined in NISTIR 7628 [5] by the National Institute of Standards and Technology (NIST). The International Society of Automation (ISA) has also created the ISA99 committee, which has developed the ISA/IEC-62443 [6] standard of Network and System Security for Industrial Process Measurement and Control. The International Organization for Standardization (ISO) along with the IEC have jointly developed the ISO/IEC TR 27019 [7] standard of Information Security Management Systems for Energy Utility Industry.

1.1 Motivation and Objectives

The state-of-the-art smart grid approaches propose a decentralized [8] DA architecture that applies hierarchical and distributed control architecture at different levels of the distribution network. Real-time communication between the various levels is necessary in order to accomplish intelligent DA functions. The decentralized DA enables efficient integration between DA components and systems by transmitting standard-based messages through an open networking infrastructure. Therefore, cyber-security has become vitally important and security measures must be designed to achieve a reliable and efficiently functioning DA.

1.1.1 Distribution Automation Components

There are several components that contribute to the decentralized DA process. The main DA sub-components are Primary substation automation, field-disconnectors automation (feeder automation), Secondary substation automation, customer automation, Data Collectors, Distribution Information Center (DIC) and the distribution control center. Real-time data communication within each of these sub-components, as well as between them, is essential if the smart grid DA goals are to be accomplished. Fig 1 shows different DA components and the communication between them required by the decentralized DA.

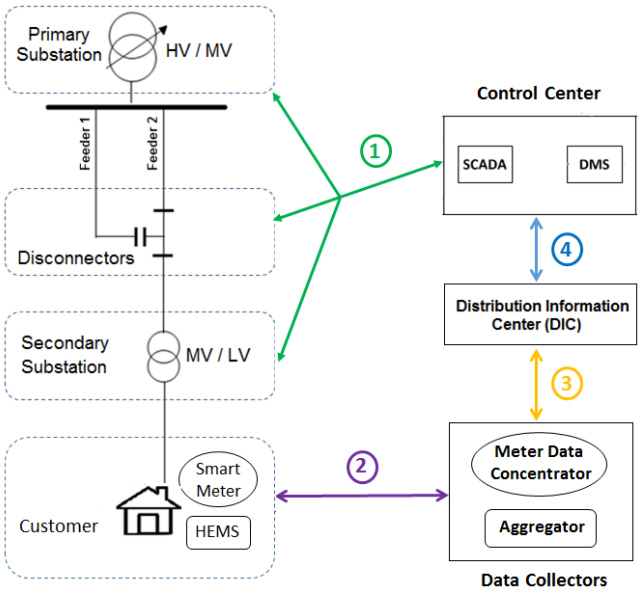


Fig 1. Data communication between DA components in decentralized DA

Decentralized DA requires both Vertical integration (to control center) and Horizontal integration (between DA components). In Fig 1, DA data communication can be categorized into four main groups. The first category includes control center and substation/field communication, substation-to-substation communication and substation to field communication. The second, customer and Data Collectors communication. The third is Data Collectors and DIC communication, while the fourth is control center and DIC communication. While the first communication category often contains Supervisory Control and Data Acquisition (SCADA) messages to/from remote devices, the second

category includes LV network measurement data as well as the data from the customers' Distributed Energy Resources (DER). In the third category, collected data from several customers are transmitted to the respective databases in the DIC. The fourth communication category relates to the Distribution Management System (DMS) that sends/receives the required information for realizing intelligent automation functions.

1.1.2 Communication and Security

Connectivity is necessary for proposing new smart grid DA functions that require integrating new resources into the DA operation. For instance, modern [8] DA concepts (for example, Active distribution network) are more interested in the real-time visibility of process data (for example, DER data). Therefore, Information and Operational Technologies (IT & OT) have to be merged to improve the operational efficiency and to decrease the integration costs. Smart grid DA facilitates integration by using standard data communication and networking protocols. Internet-based data exchange, i.e. communication over Internet Protocol (IP), is regarded as the latest trend for decentralized DA communication because of its compatibilities with the latest generation of SCADA [9], Internet-of-Things [10] devices in the fields/customer sites, and integration methods [11] for databases in DIC. Furthermore, modern automation (control) networks adapt to the Ethernet and Transmission Control Protocol (TCP)/IP, and integrate to enterprise networks [12] via IP-based communication.

Internet-based communication has many benefits, such as cost-effective connectivity and interoperability between DA components. However, this communication also presents cyber-security challenges [13] that can have physical consequences because of the Cyber-Physical-System [14] nature of the smart grid. Security attacks [15] on the DA systems may lead to industrial espionage, system malfunction, blackouts and serious damage to the distribution network environment. All of the above points to the necessity of applying cyber-security solutions that will ensure the reliable DA operation. The principles of security must be taken into account in the planning, design and operational phases of DA.

1.1.3 Research Scope

As stated above, secure Internet communication is essential for the reliable integration of DA components and the realization of smart grid DA functions. The following research questions will define the research scope of this dissertation:

- Can we implement smart grid DA functions by exchanging information (even non-IP protocols) on top of the IP and utilizing the existing networking infrastructures in a way that satisfies the requirements for multiple actors such as DSO, meter provider and customers?

- Can we use standardized IT security protocols and create dependable communication for smart grid DA functions in which information security and automation real-time requirements are met?
    - It should be noted here that the main focus of this dissertation is on the security requirements rather than the automation real-time requirements.

- Can we manage intelligent DA functions hierarchically within decentralized DA by applying new automation solutions that support industrial ICT and distribute decision-making over the distribution network?

Fig 2 depicts the research scope of this dissertation, which is a combination of smart grid DA function, industrial ICT and information security.

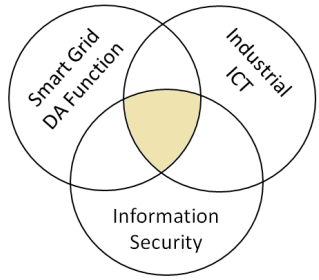


Fig 2. The research scope of this dissertation

Concerning Fig 2, smart grid DA functions selected for this dissertation are substation automation, feeder automation, Logic Selectivity, customer automation and Smart Metering. Industrial ICT includes information integration via power-system automation standards and Internet communication. Information security comprises applying IT security protocols at different layers of the Open Systems Interconnection (OSI) model. As can be seen in Fig 2, the research scope is a combination of three disciplines. Consequently, the research objectives are multidisciplinary as they encompass a broader range of issues than could be handled by a single discipline study that would focus more deeply on a specific problem in just one of the aforementioned disciplines.

1.1.4 Multidisciplinary Research Objectives

This multidisciplinary research creates a link between the three disciplines outlined in Fig 2, and has two aims:

- Confidentiality, Integrity and Availability are defined as the high-level security requirements for the smart grid information networks [5]. The first aim is to meet these high-level security requirements for the local DA communication, as well as remote DA communication over the Internet with deterministic behavior.

- The second aim is to provide real-time connectivity and distribute intelligence in decentralized DA by proposing innovative solutions in the distribution substations.

These aims will be accomplished by fulfilling the following multidisciplinary research objectives (Parts 1 and 2), which correspond to the above-mentioned aims, respectively.

1.1.4.1 Multidisciplinary Research Objectives – Part 1

Smart grid security is regarded as a new field of research, which is still in the early stage of its development [16]. While the importance of smart grid security has been identified and recommendations have been made by government and industry professionals in [3][5], there is as yet no common security framework for protecting communication in smart grid DA. Indeed, most of the DA communication standards have no built-in security mechanisms since they were developed when cyber-security was not a big issue for the industrial networks. For instance, the well-known IEC TC57 standards (such as IEC 60870-5-104, IEC 60870-6, IEC 61968 and IEC 61850) and DNP3 originally lacked internal security mechanisms to provide end-to-end security. Because of this, IEC subsequently published the IEC 62351 standard for handling the security of the TC57 standard series. Although the IEC 62351 standard does address some security requirements, it is not yet in its final version and it is expected that further [17][18] security mechanisms will be proposed. Consequently, the current smart grid DA equipment has no support for IEC 62351, as it is recognized that it is still under development and may yet undergo major changes.

Several security solutions have been proposed [19,20,21,22,23] for securing DA data communication. The proposed security protocol in [19] protects DA data communication,

but it is a proprietary protocol, which means that there are issues concerning security management and implementation. In [20][21], the addition of security extensions to the SCADA communication protocols are proposed. However, the implementation is tedious and requires upgrading of the Data link layer. Although secure aggregation protocols are proposed for the hierarchical collection of metering data in [22][23], these are not reliable enough and contain security vulnerabilities [16] relating to an attacker penetrating the aggregation process and accessing large quantities of critical data by decrypting just one single aggregation packet. Moreover, while a secure framework for data exchange in a Home Area Network (HAN) has been proposed in [24] for similar nodes supporting ZigBee, information integration for dissimilar nodes will also be required especially for other HAN communication technologies of interest [25] such as the Ethernet. Furthermore, the HAN communication in [24] still requires more reliable security protocols in order to avoid the security issues implicit in ZigBee [26]. While the existing security protocols in IT networks may not provide the security requirements for all the DA application areas (for example, IT security protocols does not fully cover industrial control security requirements), but they do secure DA data exchange (particularly DA Internet communication) in many applications because of the following reasons.

First of all, the broadly used security mechanisms in computer networks are compatible with DA data exchange because industrial ICT standards are based on the OSI model, and automation networks also tend to integrate [12] enterprise networks to bridge the gap between the automation and IT systems. Also, although automation networks differ [27] from computer network concerning to real-time requirements and continues functioning, there are also many similarities in terms of using widely accepted networking protocols and technologies. In addition, there are differences [16] between a smart grid DA Internet and the regular Internet in terms of traffic type, performance metrics, communication model and more importantly timeliness of data delivery. However, recent advancements in the Internet access technologies provide high-performance Internet with the increased bandwidth that is able to deliver fresh [27] data to the decision-making elements in DA.

This dissertation addresses the applicability of IT and computer security solutions at different layers of the OSI model in order to achieve secure DA communication through the establishment of secured messages, secured communication paths or both. The following multidisciplinary research objectives are defined in below:

- To create secured messages for the communication in customer automation and Primary substation automation.
- To build secure communication paths for the communication in Smart Metering, feeder automation and Logic Selectivity.
- To evaluate substation's remote communication security by alternative solutions: secured messages and secure communication paths.
- To investigate the impact of the communication network on Logic Selectivity real-time performance.
- To analyze the effect of dependable (Secure and Real-time) Logic Selectivity on the distribution network's reliability.

1.1.4.2 Multidisciplinary Research Objectives – Part 2

The decentralized DA enhances the robustness of the system by distributing the intelligence (via investment in controllability and ICT) over different levels [8] of the distribution network, such as substations. While the automation capabilities of Primary substations are enhanced, Secondary substation automation is also initiated through the addition of a new automation device, i.e. Secondary Substation Automation Unit (SSAU).

In Primary substation, the protection and automation systems are linked in order to provide new functionalities such as the Centralized Protection System (CPS) that was introduced by ABB. While different studies [28][29][30] have addressed CPS from the protection algorithms' perspective, it can also be applied to feeder automation function.

In Secondary substation, SSAU requirements were investigated in IDE4L [31] project conducted in cooperation with Tampere University of Technology. SSAU supports the advanced automation and ICT standards [32] used for creating new intelligent automation functions [33]. In addition, it can also be applied in the Smart Metering Process.

The following multidisciplinary research objectives are defined:

- To consider Primary substation in feeder automation decision-making and to create Horizontal integration between CPS and filed-disconnector.
- To consider Secondary substation in Smart Metering process and to create Horizontal integration of SSAU with customer site and DIC.

1.2 Contributions

These contributions are related to the multidisciplinary research objectives-part 1:

- **Publication 1** develops an integration solution for heterogeneous communication interfaces (Serial and Ethernet) and protocols (CANopen and TCP/IP) in HAN. Mutual authentication over SSL is proposed for securing the HAN communication.
- **Publications 2 and 6** propose Station Gateway as the key device for providing security in Primary substation's local and remote communications. The local communication is secured by developing the proxy server application (supports both IEC61850 and TLS) in the Station Gateway. The remote communication security is achieved by adding OPC UA wrapper functionality to the Station Gateway and create end-to-end security via OPC UA security model. In addition, Publication 6 evaluates security in the substation's remote communication by comparing security mechanisms in two application layer protocols (OPC UA and IEC 60870-5-104) and two types of VPN (PPTP and IPsec).
- **Publications 3 and 4** establish secure communication paths for metering data and Decentralized feeder automation messages by proposing PPTP and IPsec tunnels.
- **Publication 5** experiments assessment of standardized Logic Selectivity in which protection, control and monitoring functions modelled with IEC61850 data model. Next, proposes L2TPv3 over IPsec for establishing a secure communication path for transmitting GOOSE messages over the Internet. In addition, it measures jitter and delay in the GOOSE recorded traffic in order to analyze them for Logic Selectivity real-time requirements. Finally, it calculates reliability indices (SAIFI and SAIDI) in case of employing GOOSE-based Logic Selectivity.

These following contributions are assigned to the mentioned multidisciplinary research objectives-part 2:

- **Publication 4** proposes CPS as the place for making Decentralized feeder automation decisions.
- **Publication 3** proposes SSAU for real-time LV network data transmission between smart meter and metering database.

1.3 Publications

There are six publications [P1]-[P6] listed in this dissertation. These publications were prepared in accordance with the top-down approach: smart grid, distribution network, DA function, communication and security. The author of this dissertation proposed all the publications and was responsible for the preparation, writing and presentation of the papers. The author has conducted all the research work with the following exceptions.

Prof. Sami Repo (as the primary supervisor) and Prof. Hannu Koivisto have been the supervisors of the dissertation and their roles in the publications have involved general discussion, guidance and commentary. In Publication 2, M. Salmenperä assisted in configuring the OPC UA wrapper and provided comments on the same paper. In Publication 5, O. Raipala helped for configuring the electrical protection parameters. M. Salmenperä and J. Seppälä prepared the communication setup for the secure Internet communication. They also commented on issues related to PICARD analysis as well as writing some paragraphs about the tunneling protocol and security. S. Horsmanheimo, H. Kokkoniemi-Tarkkanen and L. Tuomimäki analyzed the recorded traffic measurements as well as writing a few paragraphs. The Logic Selectivity algorithm was invented and implemented at the device level by A. Alvarez, F. Ramos, A. Dede, and D. D Giustina. In Publication 6, J. Seppälä has commented on the security related issues.

1.4 Structure of Dissertation

Following this introduction, chapters 2 and 3 describe smart grid DA functions and the industrial ICT discussed in the above publications. Chapter 4 explains cyber-security in DA data communication, while Chapter 5 defines the research methodology and materials. The security solutions ensuring smart grid DA functions are discussed in Chapter 6 and the dissertation' conclusion is presented in Chapter 7.

2 SMART GRID DA FUNCTIONS

This chapter provides the background information for realizing the smart grid DA functions that are the focus of this dissertation.

2.1 Remote Control and Monitoring

High-level DA decisions are made by the control center applications that receive data from remote distribution devices and DIC. The control center contains SCADA and DMS applications that monitor and manage MV network operation. SCADA applies remote-to-field communication for exchanging measurement data, status of switches and control commands. DMS carries out remote-to-corporate communication with DIC in order to exchange the data values required to perform intelligent functions.

2.1.1 Supervisory Control and Data Acquisition (SCADA)

SCADA enables control center to collect data from the remote facilities and to send control instructions to them. The changes in SCADA architecture can be described as shifting from Monolithic to Distributed to Networked generations [34]. In the traditional Monolithic-SCADA, the Master Terminal Unit collects data from Remote Terminal Units (RTUs) via Wide Area Network (WAN) by using manufacturer-dependent communication protocols. A Monolithic-SCADA does not integrate the distribution network data with other applications in the control center. In a Distributed-SCADA, a LAN is used in the control center in order to share SCADA data with other network components (like DMS) via proprietary protocols. Finally, the Networked-SCADA utilizes an open network infrastructure and standard protocols [35], not only for communicating with the remote field devices but also for interconnecting with the DMS.

2.1.2 Distribution Management System (DMS)

DMS [36] provides new DA functions by integrating process data (SCADA data) and the distribution network data (geographic, network components and management data), which are acquired from DIC databases. DMS has functionalities such as topology management, real-time network analysis, automated outage planning, Volt/VAR

optimization, fault management and supply restoration. DMS has been developed incrementally by adding new intelligent tasks that use existing distribution network data to perform new functions. Realizing DMS tasks requires the use of SCADA real-time data, which means that there must be data exchange between DMS and SCADA applications. Several versions of DMS to SCADA integration have evolved over time. While proprietary communication protocols were used in the initial versions, standardized Application Programming Interface (API) i.e. Open Platform Communications Data Access (OPC DA) has been used in later versions. The most recent version applies Web Service interface with the messages defined in the IEC 61968. Additionally, realizing DMS tasks requires the use of network data in DIC databases.

2.1.3 Distribution Information Center (DIC)

A distribution utility company maintains a number of information systems containing data related to the customers, the network facilities, maintenance and the geographic locations of the feeders. Moreover, smart grid application areas, such as Smart Metering and Distributed Generation (DG), have presented new information systems that are applied to modern DA and an Active distribution network [8]. Table I describes the information systems in a DIC.

Table I. Description of the information systems in DIC

Static Data	**NIS**	This includes technical and economic data about the distribution network assets, [2]. The NIS also contains calculated values for the short-circuit fault currents and load flows in different locations of the distribution network.
	CIS	This database stores the customers' identification data, such as the customer type, customer delivery point and the customer load profile.
	GIS	GIS includes geographical information about the distribution network locations. The DMS uses this information to visualize the distribution network, the MV feeders' topology and the MV fault management.
Dynamic Data	**WIS**	This manages information about field crews. In fault conditions, DMS informs the WIS to organize work assignments for the respective field crews.
	MIS	MIS database contains collected data (customer consumption, power quality measurements and LV fault information) from customers' smart meters via the smart metering process [37].
	AIS	This stores DG/DER data that is collected by the aggregator [8] from the Home Energy Management System (HEMS) inside a customer's premises. DMS uses this database for Active distribution network management and integrating local generation into the electricity network operations.

In Table I, DIC elements can categorized into two main groups. The first group, consisting of Network Information System (NIS), Customer Information System (CIS), Geographic Information Systems (GIS) handles static data. The second group, consisting of Work Information System (WIS), Metering Information System (MIS) and Aggregator Information System (AIS) for the relevant DSO, handles dynamic (real-time) data. These information systems are used for statistical, commercial, billing and technical purposes.

2.2 Substation Automation

Substation Automation can be implemented in both Primary and Secondary substations. Although most of the Substation Automation Systems (SAS) have been designed for Primary substations, the potential of Secondary substation automation will also be utilized more in any smart grid DA.

2.2.1 Primary Substation Automation

In Primary substation, SAS provides automation at both the substation and distribution network levels. At the substation level, SAS creates local automation for voltage control, reactive power compensation and automated switch sequences. At the distribution network level, SAS systems send measurements, status of switches, disturbance recorders and events to the control center. In addition, they receive control commands, acknowledgments, settings, and configuration parameters from the control center.

Traditional SAS apply analog signals via hardwiring for receiving the feeder measurements, and manufacturer-dependent Fieldbuses for exchanging data between the substation relays. The Fieldbus interface presents substation data to the substation computer and Remote Terminal Unit (RTU) for the local and remote usage, respectively. However, in a modern substation, the entire substation data is exchanged digitally between the measurement, protection and control devices via the substation's LAN.

2.2.1.1 Modern Substation Architecture

A modern substation LAN contains three logical levels: Process level, Bay level and Station level [37]. The Process level includes measurement transformers and sensors that provide process data via the network communication interface, rather than through analog

hard wiring. Intelligent Electronic Devices (IEDs) are located at the Bay level. These IEDs are the latest substation automation devices, and are intelligent, programmable and support advanced ICT protocols. Examples of such IEDs include the feeder/busbar protection relay and the bay/voltage controller. The Station level consists of monitoring and higher level automation devices including Human Machine Interface (HMI), substation computer, and Station Gateway. These substation levels are connected via Industrial Ethernet (IE) switches in which measurement transformers, IEDs and automation applications are able to communicate through a single Ethernet network using the uniform, interoperable [38] communication protocol that is the IEC 61850 standard. In Fig 3, the IE switches are also linked together via a redundant network topology, such as a ring, in order to increase substation data availability.

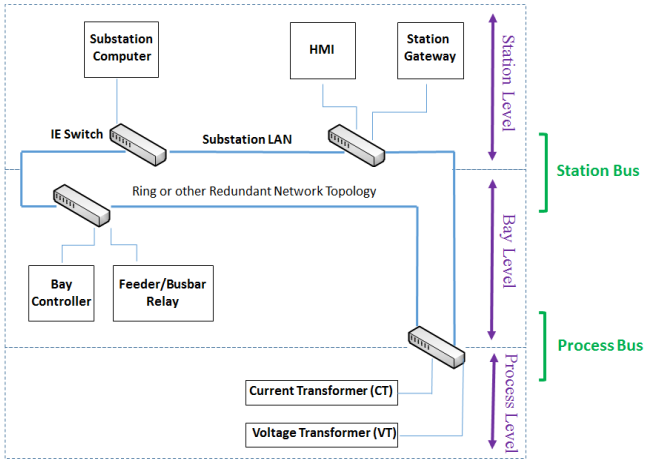


Fig 3. Modern Primary substation architecture [37]

In Process level, measurement transformers publish current and voltage values as digitized Sampled Values (SV) in the IEC 61850-9-2 format. At the Bay level, the intended IED subscribes the published values and performs the protection function. Bay level IEDs also exchange data with other IEDs for monitoring and control purposes. Station level is the place at which the substation LAN is connected to a remote network.

There are two other terms in a substation LAN, which need to be defined: Process bus and Station bus. Process bus is intended for communication between the Process and Bay levels, while the Station bus refers to communication between the Bay and Station levels.

2.2.1.2 Specific Requirements for Substation LAN

There are a number of similarities between a substation LAN and an ordinary computer LAN. However, the SAS imposes specific requirements, time synchronization and network redundancy, on the substation LAN standards. The on-time delivery of data to substation IEDs and outdoor devices requires an extremely precise time-synchronization method. The most recent substation IEDs support Ethernet technology and are able to use the same network to exchange both process data and timing information. Therefore, a Network Time Protocol (NTP) or a Simple Network Time Protocol (SNTP) can be used for time synchronization. The accuracy of these protocols is within the millisecond range, but does not satisfy the extreme time-demanding applications such as Process bus SV (IEC 61850-9-2) and Synchrophasor (IEEE C37.118 and IEC 61850-90-5) applications [40][41]. These applications require time synchronization accuracy at the microsecond range. The IEEE 1588v2 Precision Time Protocol (PTP) [39] provides the required level of accuracy and should be used for the time synchronization of substation LAN devices.

In addition to the above, network redundancy solutions with extremely fast recovery times should be used in a substation LAN because data availability is critical for the continuous operation of the IEDs. Although Spanning Tree Protocol and Rapid Spanning Tree Protocol are often used to manage redundant topologies in a regular computer LAN, they are not suitable for substation LAN because of their long recovery times, which can take several seconds. The IEC 62439 standard defines suitably fast redundancy Ethernet protocols [42] such as Media Redundancy Protocol, Parallel Redundancy Protocol (PRP), High-availability Seamless Redundancy (HSR), Cross-network Redundancy Protocol, Beacon Redundancy Protocol and Distributed Redundant Protocol. In a substation LAN, the best solutions are HSR [43] and PRP [44] because they provide zero recovery time.

2.2.2 Secondary Substation Automation

In a distribution network, a substation that transforms MV to LV is known as a Secondary substation. Legacy Secondary Substations mainly include MV/LV transformers and fuses for protecting the LV feeders, but there is no automation, or at best only simple automation functions such as that provided by a typical RTU. However, Secondary Substation automation [45] will become more important in future DA, and will make these substations capable of advanced automation and communication functionalities.

This is achieved by using an SSAU that provides monitoring and control functions at Secondary substation level. The SSAU has new smart grid functions, such as fault current measurement, fault indicators, optimization of power flow, power quality control and LV grid management. The requirements for the next-generation SSAUs have been studied in the IDE4L project [46], which was carried out by participating Tampere University of Technology. An SSAU includes various functional modules, as is shown in Fig 4.

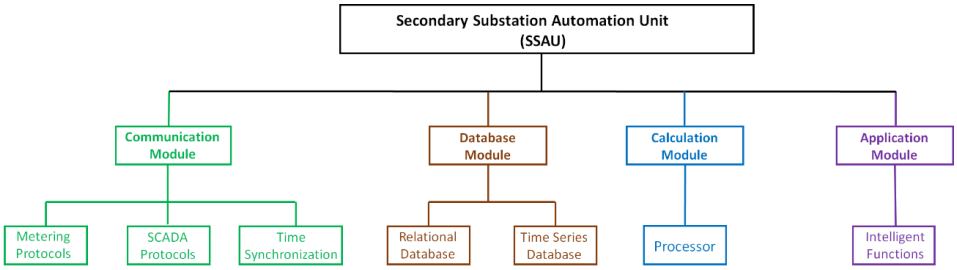


Fig 4. Modular structure of the Secondary Substation Automation Unit (SSAU)

The SSAU includes four main modules: the Communication, Database, Calculation and Application Modules. The Communication Module handles the integration of SCADA and third-party devices to SSAU. This module is also used for local time synchronization of the SSAU via the use of NTP, SNTP or IEEE 1588v2 PTP. The Database Module can be either a Relational Database Management System or a Time Series Database. The Database Module is the data hub in the SSAU, which receives data from third-party devices and provides data for internal and external applications. Fig 5 shows an example of data communication to/from an SSAU using metering and SCADA protocols.

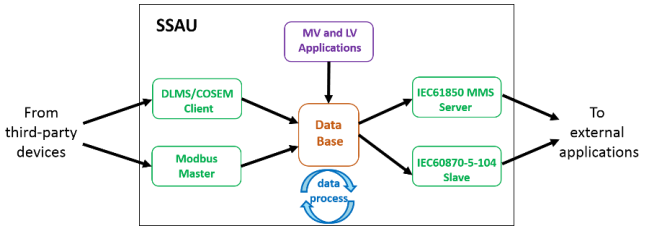


Fig 5. Data communication to/from SSAU

The Calculation Module includes processor for data processing, running programs and protocols. An industrial computer with Linux or Microsoft Windows operating system

can be used as the hardware for SSAU. Application Module includes intelligent algorithms for distributing DMS functionality over the Secondary substation level.

2.3 MV Fault Management

The MV fault management process involves three main steps: fault detection, fault isolation and supply restoration. Fault detection is realized by a local protection IED. In the fault isolation step, the fault is located and the protection IED isolates the faulty area by sending a trip command to its circuit breaker. In the restoration step, the distribution network's topology is changed in order to restore power to the rest of network.

In a fault condition, power is disrupted within one part of the radial distribution network and the affected customers experience an outage. In this situation, the DSO enhances service continuity by using backup feeders that restore power to the affected customers. Service continuity can be enhanced by utilizing several factors in the Design, Implementation and Operation phases of the distribution network. In Design phase, MV feeders are designed in accordance with the Open Ring Structure, in which the feeder's topology is radial but structured as a ring by allocating a normally open switch. The Open Ring Structure is applied for designing back-up feeders for power restoration. In Implementation phase, protection IEDs must be configured to be Selective, which means only a minimal part of the network has to be isolated during the fault occurrence. Protection IEDs provide Selectivity via two main methods: time-based Selectivity, which configures the operational delay, or communication-based Selectivity, which exchanges blocking messages [47]. In the Operation phase, there are two approaches [48] for increasing service continuity: Fault Detection Isolation and Restoration (FDIR) and Logic Selectivity. These methods can be implemented in Centralized or Peer-to-Peer architectures. Centralized architecture applies Vertical integration while Peer-to-Peer architecture uses Horizontal integration to accomplish their restoration decisions.

2.3.1 Centralized Architecture (Restoration by DMS)

In a fault condition, service continuity can automatically be realized with the FDIR method, which applies coordinated interactions between the IEDs and the switching devices. In [49], various solutions are proposed for FDIR. The main challenge in FDIR is

automatic restoration after fault detection and isolation. DMS can act as the central location for making restoration decisions during the FDIR process. Below, the FDIR and restoration steps are explained for the fault condition shown in Fig 6.

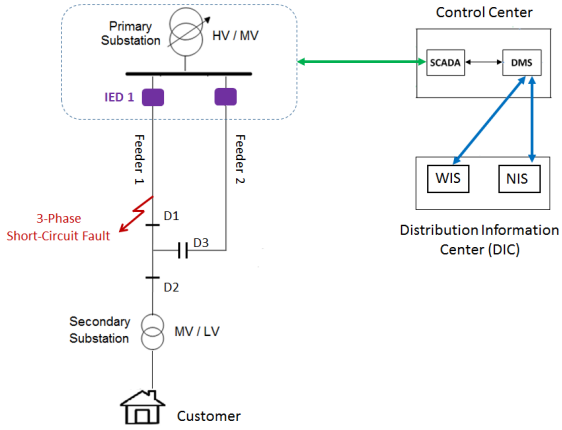


Fig 6. Supply restoration by DMS

Protection IED 1 detects a short circuit current and is activated. This results in the opening of the feeder 1 circuit breaker and the subsequent outage experienced by the customers connected to feeder 1. Then, IED 1 sends the value of the measured-fault-current to the SCADA as an event. Next, the SCADA informs the DMS about the received value from IED 1. The DMS requires this value (measured-fault-current) to automatically estimate the fault location in the distribution network. The DMS then communicates with the NIS, which contains the distribution network's static data, including the feeder 1 data.

In the NIS, the fault currents have been previously calculated (calculated-fault-currents) for all the feeder 1 zones: Primary substation to Disconnector 1 (D1), D1 to D2, and D2 to the Secondary substation. The DMS receives the calculated-fault-currents from the NIS and compares them with the measured-fault-current received from SCADA. The fault location is automatically estimated to be where these values overlap. Then, the DMS runs its supply restoration algorithm and makes intelligent restoration decisions, i.e. opening D1 and closing D3. Next, the DMS informs SCADA to execute its restoration decisions by sending control commands to the remote disconnectors (D1 and D3). Finally, the DMS sends an information request [50] to the WIS to dispatch a field crew for fault clearance. The WIS sends an SMS/email/call to the crew to inform them about the fault location.

2.3.2 Peer-to-Peer Architecture (Restoration by Logic Selectivity)

Automatic supply restoration can be accomplished in a Peer-to-Peer architecture via Horizontal integration, local processing and a distributed intelligence model. An example of Peer-to-Peer architecture is Logic Selectivity, which exploits communication-based selectivity and aims to maximize distribution network Selectivity, thus reducing the number of outages and enabling faster reconfiguration during a fault condition. Logic Selectivity is regarded as a highly efficient service continuity method, but it requires substantial investment in feeder switching devices (replacing some switch disconnectors with circuit breakers), substation IEDs, and the communication network between them.

In a fault condition, the operation time of the downstream IEDs must be less than that of the upstream IEDs. Logic Selectivity provides protection Selectivity by using a blocking signal that enables faster operation of the IEDs closer to the fault. This requires an algorithm that is designed to consider blocking messages. Blocking messages block the operation of the protection function in the upstream IEDs. These messages can be based on a proprietary [51] protocol or they can be standard [52] blocking messages in the form of Generic Object Oriented Substation Event (GOOSE).

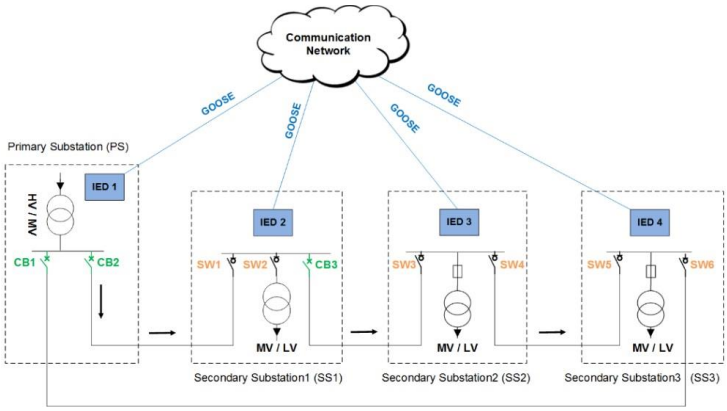


Fig 7. An application of standardized GOOSE-based Logic Selectivity

Fig 7 shows an example of GOOSE-based Logic Selectivity application. The power flow is from Primary (upstream) substation to Secondary (downstream) substations. All the substations are equipped with IEDs that control the respective Circuit Breaker (CB IED) and/or the attached Switch (SW IED). Implementing efficient Logic Selectivity requires

that there is a circuit breaker in at least one of the Secondary substations. Thus, a circuit breaker is used in the first Secondary substation (SS1). Furthermore, all IEDs should be equipped with some level of intelligence for executing the algorithm applied for fault isolation and supply restoration. This algorithm's design must take into account different parameters relating to power direction, fault detection and switching devices.

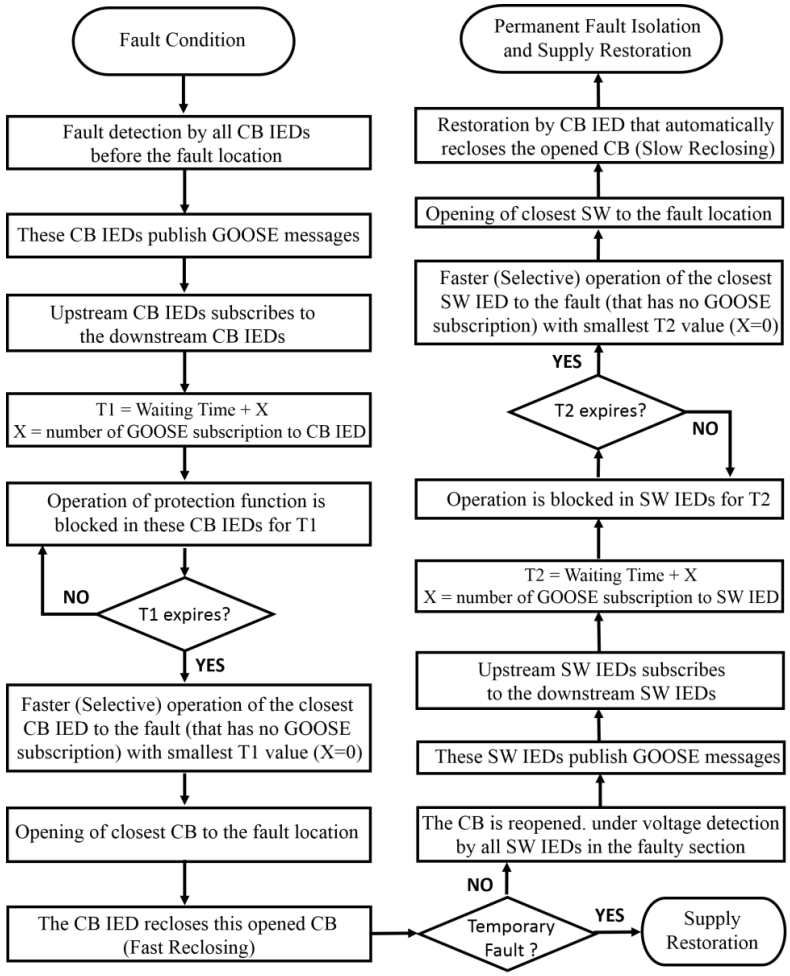


Fig 8. The GOOSE-based Logic Selectivity algorithm

A summary of the Logic Selectivity algorithm [53] that is used for the network in Fig 7 is presented in Fig 8, above. This algorithm adapts [54] IEC61850 standard, and can be

defined in ISaGRAF [55]. The algorithm includes three main stages: fault isolation by CB IEDs that open the closest breaker to the fault, further minimizing of the faulty section by the SW IEDs that open the nearest switch to the fault, and service restoration by CB IED that recloses the opened breaker after passing the reclosing time. There are also two (fast and slow) reclosing times for handling temporary and permanent faults, respectively.

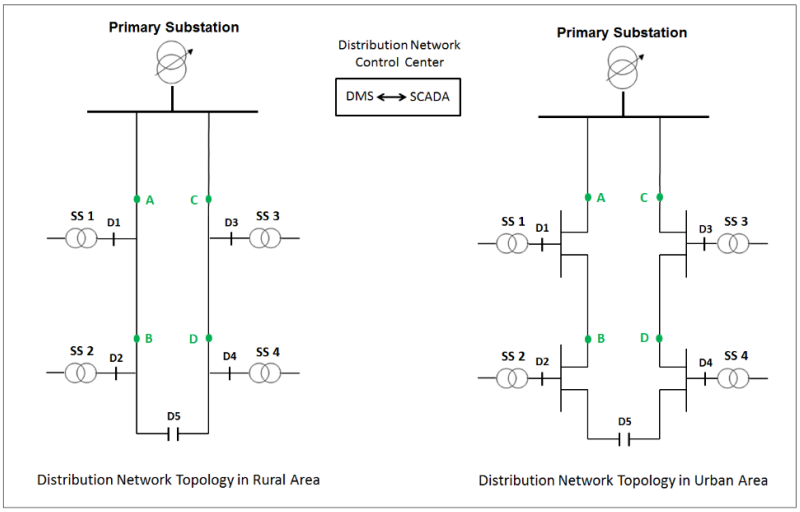
In the algorithm, T1 and T2 values have key roles and they make the operation time of the upstream IEDs greater than that of the downstream IEDs. The number of GOOSE subscriptions to each IED determines the X value and, consequently, T1 and T2 values. The subscription of the upstream IEDs to the GOOSE messages published by the downstream IED must occur within Waiting Time in T1 and T2 formulas. In other words, the accurate operation of the algorithm requires the blocking message exchange between IEDs within the Waiting Time, which is usually in millisecond range (e.g. 100ms).

A Peer-to-Peer architecture is considered more efficient than a Centralized architecture because it has faster operation, autonomy (restoration decisions are locally made by the field IEDs with no central controller), robustness (failure of one IED does not stop the entire process), scalability (adaptation of system for adding new IEDs) and reliability (decentralized decision making with no single-point-of-failure).

2.3.3 Feeder Automation

Both the Centralized and Peer-to-Peer architectures allow for the automatic operation of the feeder switching devices, i.e. feeder automation as a subsection of DA. Feeder automation is actualized through FDIR, Logic Selectivity, automatic transformer/feeder load transfer, self-healing mechanisms and load balancing [56].

While some degree of feeder automation can be achieved using devices such as pole-mounted reclosers and sectionalisers [37], fully automated feeder automation can be fulfilled via the use of advanced IEDs interacting to make feeder automation decisions. These decisions can be made in different locations in the distribution network such as the control center, substations or even in-field. Publication 4 [P4] introduces four feeder automation approaches: Semi-Automatic, Centralized, Decentralized and Distributed explaining by Fig 9. This figure also includes a table that lists the devices required to implement each approach, the required elements in the four highlighted points (A to D), Disconnector 1 to 5 (D1 to D5), Primary Substation (PS) and Control Center (CC).



	A	D1	B	D2	C	D3	D	D4	D5	PS	CC
Semi Automatic	Recloser	----	Sectionaliser	----	Recloser	----	Sectionaliser	----	----	----	----
Centralized	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Remote I/O RTU	IED	Agent
Decentralized	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Remote I/O RTU	IED Agent	----
Distributed	Recloser Agent	IED Agent	Recloser Agent	IED Agent	Recloser Agent	IED Agent	Recloser Agent	IED Agent	IED Agent	----	----

Fig 9. Feeder automation approaches and the required devices for each approach

Fig 9 illustrates a distribution network with two MV feeders designed in accordance with the Open Ring Structure, in which D5 is normally open but the other disconnectors (D1 to D4) are normally closed. There are also four Secondary substations (SS1 to SS4). The approaches to feeder automation are classified based on the location of the agent software (which makes the feeder automation decisions), the intelligence level of the controlling devices and the functionality of the switching devices. In Fig 9 the required devices are proposed to achieve maximum distribution network reliability. However, in practice some of these devices may be changed, depending on their cost and the load criticality.

2.4 Customer Automation

Customer domain [1] of the smart grid will include new application areas such as home automation and smart charging [57] of the electrical vehicles. Furthermore, there is a shift away from passive customers towards more active customers who participate in the distribution network operation by providing their local generation and flexibility services [8] to the market. Therefore, an intelligent customer automation and LV grid data management system is required. Customer automation is a new dimension for DA. It requires smart meters and HEMS, which provide customer data to the Data Collectors that shown in Fig 1. These collected data are used for different purposes, including Active distribution network [8] in which energy resources at the customer premises are controlled in real-time in order to achieve the goals of Demand-side integration [58].

2.4.1 HEMS for Demand-Side Integration

Demand-side integration aims to meet the Active distribution network constraints by managing customer loads through consumer load control, and by integrating local generation capacity into the electricity network operations. The decision to integrate local energy resources can be made at one of the four levels shown in Fig 10.

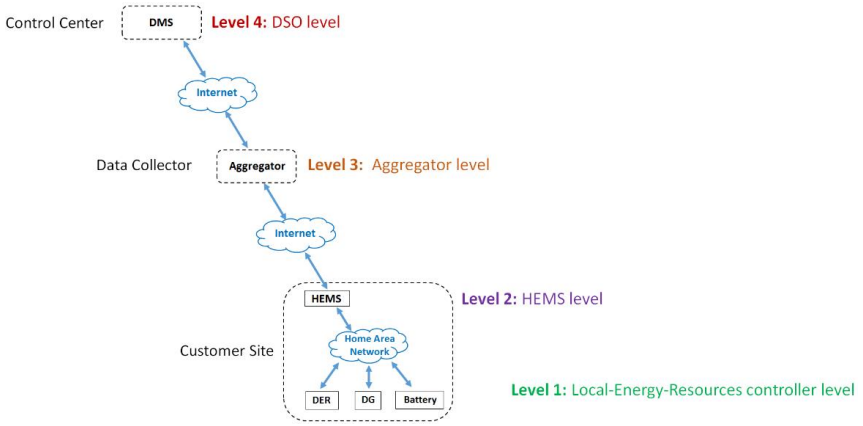


Fig 10. Demand-Side Integration decision levels

Each level has its own role in the complete system and the higher levels always co-ordinate operation at the lower levels. These different levels have different ways of

making wise decisions, based on several factors such as DSO policy, specific use-case, and the general scenario.

HEMS provides smart grid features such a, energy scheduling, load prioritization, home appliance energy efficiency, local energy management and Demand-Side integration decisions. Effective HEMS operation requires real-time data communication to both Aggregator and customer's energy resources via the Internet and HAN, respectively.

2.4.2 HEMS Communication in Home Area Network

A local network connecting a group of smart digital devices together within the customer's premises is called HAN. Smart home appliances, including HEMS, use the HAN to carry out the communication requirements for home automation applications.

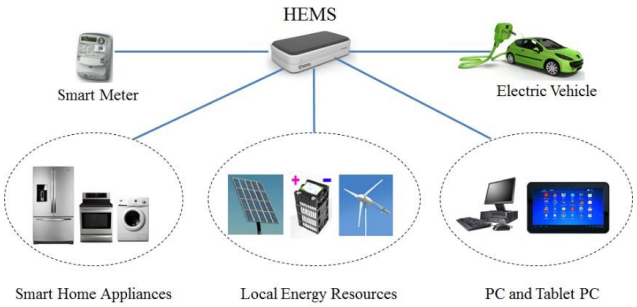


Fig 11. HEMS communication in Home Area Network

As can be seen from Fig 11, HEMS communicates with smart meter, electric vehicle, smart home appliances and local energy resources. HEMS provides various automation functions such as handling Demand-Side integration decisions by running an intelligent energy management algorithm [59] [60] that controls local energy resources for various situations, such as production following optimization and peak load management.

Home automation applications often require cost-effective and low-power-consumption communication. Therefore, communication technologies with low data rates (up to 100kbps) and short communication ranges (up to 100m) are usually utilized in HAN [61].

HAN takes advantage of various wireless and wired networking technologies. Some examples of the wireless technologies it uses [62] are WiFi, Z-Wave, ZigBee, Bluetooth

and 6LoWPAN. The wired technologies can be [62] Ethernet, HomePlug, HomePNA and serial communication protocols such as Controller Area Network (CAN). Integration of these different communication technologies and security are the key challenges in HAN. These wired/wireless protocols can be used in HAN for communication of HEMS (level 2 in Fig 10) with local energy resources (level 1 in Fig 10) controller. This controller is an IED in case of DER/DG, and a Battery Management System (BMS) in case of battery.

2.5 Smart Metering

A smart meter acts as a sensor that supports real-time bidirectional communication, which is the essence of Smart Metering. The term Smart Metering implies a system that automatically measures, records, analyzes and controls customers' energy consumption with the aid of advanced measurement and communication technologies [37]. Smart Metering system includes three main elements: Automated Meter Reading (AMR), Advanced Metering Infrastructure (AMI) and Automated Meter Management (AMM). AMR utilizes digital data communication protocols/techniques for automatically collecting data from the remote smart meters. AMI is the network architecture that provides bidirectional data communication between smart meters and utility information systems. AMM manages and stores customer data in the information systems.

2.5.1 Smart Metering Data for Smart Grid DA Applications

Traditional DA was only based on MV data, and was unaffected by LV network data. However, smart grid DA also utilizes LV network data, as well as collecting information from DER. Smart Metering is used to collect LV network data to accomplish new application areas such as Active Network Management (ANM) and Advanced Distribution Automation (ADA). ANM [8] is regarded as the newest distribution network management model as it enhances the network's hosting capacity by utilizing decentralized DA and DER flexibility services. ANM operation requires both LV network data and DER data, which are collected by Smart Metering and Aggregator, respectively.

In addition, the collected LV network data provided by Smart Metering adds advanced LV automation functions to DA. LV data is applied for ADA in which control center becomes capable of real-time LV grid monitoring and fault management [63]. The most

recent smart meters are able to indicate different LV network faults such as neutral conductor fault, blown fuse, over/under voltage and wrong phase order [64]. ADA utilizes smart meter data and provides LV network fault detection and location capabilities.

2.5.2 Smart Metering Architecture in the Distribution Network

Smart Metering in the distribution network includes automatically collecting LV network data from smart meters and storing them in the respective database in DIC.

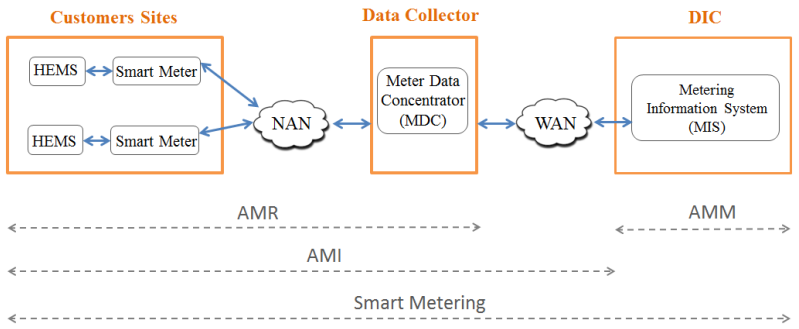


Fig 12. Smart Metering architecture in the distribution network

Fig 12 shows the Smart Metering architecture utilized in Finland. At the customer site, smart meter communicates locally with HEMS and remotely with Meter Data Concentrator (MDC) through Neighborhood Area Network (NAN). The smart meter's communication with the NAN can be carried out via wired network such as Power Line Carrier and public telephone network or through wireless networks such as ZigBee, WiFi and cellular networks. Communication network technologies with 100 kbps–10 Mbps data rates and 10 km coverage distance are frequently used in NANs [61]. However, the design of a NAN depends on several factors [65] such as the number of smart meters, communication medium, cost, and the amount of data transfer. The NAN topology can be varied but it must satisfy the timing requirements of the metering applications. For instance, ad hoc network and mesh network can be designed as a NAN topology [65].

In Fig 12, MDC utilizes a WAN for transmitting data collected from several smart meters to MIS database in DIC. The WAN supports higher data rates (10 Mbps–1Gbps) over greater distances (100 km) than a NAN [61]. The WAN uses IP-based communication that can be achieved through optical communication, cellular networks or satellite.

3 INDUSTRIAL ICT AND UTILITY INTERNET

Traditionally, a wide variety of communication protocols and separated networks were utilized for communication in different components of DA. However, smart grid improves integration by applying standard messages and communication network.

3.1 Communication Standards in Decentralized DA

Below, the most popular communication standards used in smart grid DA, which were applied in publications [P1]-[P6], are explained.

3.1.1 IEC 60870-5-104

IEC TC 57 defines IEC 60870-5 standard series for process and telecontrol data communication in electric power system. The latest version is IEC 60870-5-104 (IEC 104) that is the most popular protocol utilized for electrical SCADA system communication in European countries. In every IEC 104 communication system, there are two communication parties: Controlling station and Controlled station. In case of DA, Controlling station can be placed in the control center that receives data from Controlled stations in remote substations/field devices. IEC 104 also defines two directions for data transfer: control and monitor. It is also possible for a device to operate in the dual-mode.

TCP/IP transports IEC 104 data over a serial line or Ethernet. IEC 104 application layer includes four groups of objects: Process, System, Parameter and File transfer information [66]. Fig 13 illustrates the structure of IEC 104 messages transmitted by Ethernet frame.

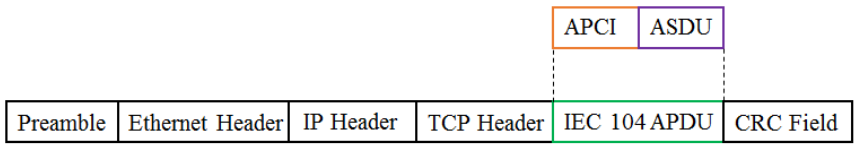


Fig 13. The structure [66] of the IEC 104 message in the Ethernet Frame

Application Protocol Data Unit (APDU) consists of two [66] main parts: Application Protocol Control Information (APCI) and Application Service Data Unit (ASDU). APCI

contains control information for managing the flow of communications. ASDU carries the application data but only contains one of the four types of the above-mentioned objects. One part within ASDU is Common address that is allocated to station. In addition, every internal data element is also identified by its Information Object Address.

3.1.2 IEC 61850

IEC 61850 standard includes information model and abstract communication services that facilitate integration between SAS from different manufactures. The hierarchical IEC 61850 data model [67] includes Physical Device (PD), Logical Device (LD), Logical Node (LN), Data Object (DO) and Object Attributes (OA). PD is the device connects to the communication network and may take the role of various LDs such as measurement, protection, monitoring and control. Every LD includes one or more LNs that are related to the various functions in SAS applications. There are LNs for measurements, circuit breakers, switches, transformers, etc. LN supports one or multiple Dos, each with unique name/s defined in the standard and related to the specific power system function. The standard also defines sets of OA for every DO. Each OA has specific name and type depending on its particular purpose. This hierarchical model provides a standard way of defining SAS and their functions as an abstract data model. The abstract model can be mapped to SV [68], GOOSE [69] and Manufacturing Message Specification (MMS) [69].

3.1.2.1 SV, GOOSE and MMS

The IEC 61850-7-2 presents the abstract communication service interfaces for the information exchange. While IEC 61850-8-1 defines the mapping of IEC61850 datasets to MMS and GOOSE protocols, IEC 61850-9-2 defines data mapping for the SV.

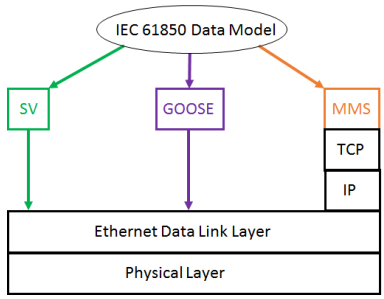
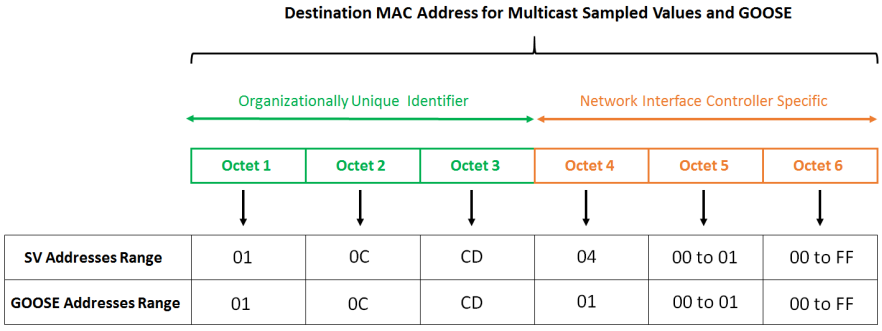


Fig 14. Mapping IEC61850 data to the OSI model layers

As can be seen in Fig 14, applications of SV and GOOSE are directly mapped to Ethernet frame but MMS applications also utilizes TCP and IP layers.

The structure of SV and GOOSE messages are explained in [70] and [71], respectively. SV and GOOSE are multicast messages that are published in the substation LAN and intended IEDs or applications are subscribed. The publish-subscribe mechanism is based on the destination multicast Media Access Control (MAC) address. Each address relates to specific SV or GOOSE data. An IED is configured to subscribe to the specific multicast address. Fig 15 depicts the hexadecimal values of destination multicast MAC address for GOOSE and SV messages. The IEC TC 57 has defined these hexadecimal values.



SV Addresses Range	01	0C	CD	04	00 to 01	00 to FF
GOOSE Addresses Range	01	0C	CD	01	00 to 01	00 to FF

Fig 15. Destination MAC address for multicast SV and GOOSE communication

MMS communication is based on client-server concept in which MMS client (for example SCADA) and MMS server (for example IED) operate over TCP/IP. This communication is typically used for read/write variables, reporting and file transfer. MMS uses IEC 61850 communication services [72] , and defines standard objects, messages, encoding rules and a set of protocols for exchanging messages between SAS.

3.1.2.2 Horizontal and Vertical Communication

In a modern substation, all of IEC 61850-compliant devices and their relationships can be officially described by using Substation Configuration Language (SCL) [73] as the XML files. The SCL files identify communication instructions such as sender, receiver, period, content and method of exchanged messages among SAS. Communication in an IEC 61850-compliant substation is categorized into two main groups: Horizontal and Vertical communications, as described in Table II.

Table II. IEC 61850 Horizontal and Vertical Communication in the Station bus

	Horizontal Communication	**Vertical Communication**
Scope	Bay level	Bay and Station levels
Direction	IED to IED	IEDs and Station Gateway/substation computer/HMI
Data Content	protection/interlocking	control command to IEDs and data/events reporting from IEDs
Message Type	GOOSE	MMS messages
OSI Layer	Layer 2	Layer 3 and 4
Data Transmission	Ethernet network	Ethernet network
Communication Model	Publish-Subscribe	Client-Server
Time Criticality	Highly time-critical	Lesser time-critical
Information Flow	SCL files	SCL file

3.1.3 IEC 62439-3 PRP

PRP is a redundancy protocol with zero recovery time. PRP operates in the layer 2 of OSI model and presents seamless redundancy for the layer 2 networks such as the SV and GOOSE. It is based on the Ethernet frame duplication that is transparent to the higher layer protocols. From topology point of view, PRP network can include both PRP and non-PRP nodes. PRP node is called Doubly Attached Node (DAN) with two Ethernet interfaces (A and B) connecting to two discrete LANs. Non-PRP device is called Single Attached Node (SAN) and contains only one Ethernet interface, as shown in Fig 16.

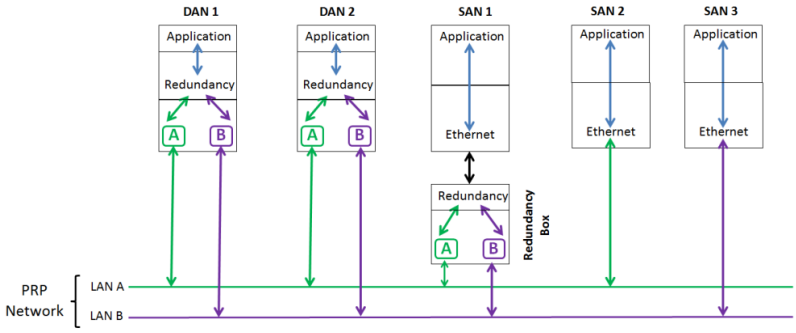


Fig 16. DAN, SAN and Redundancy Box in the PRP network

SANs connect to only one LAN in a PRP network, and exchange data with other SANs in the connected LAN. However, SANs can act like DANs via the Redundancy Box [44].

3.1.3.1 Link Redundancy Entity (LRE)

Every PRP device has two Ethernet interfaces but with the same MAC addresses. Redundant transmission via two Ethernet controllers is managed by the Link Redundancy Entity (LRE) software that duplicates each data frame [44]. A mechanism is required for handling the duplicates at receiver side. There are two [74] methods for handling duplicates: Duplicate Accept and Duplicate Discard. While receiver delivers both original frames to the higher layer protocol in Duplicate Accept, LRE performs duplicate filtering at Data Link layer in Duplicate Discard. This method is preferred mechanism since LRE delivers just one data frame to the upper layer and offloads the application processor.

In Duplicate Discard, LRE recognizes duplicated frames with Redundancy Control Trailer (RCT) [74]. In this method, the overhead bits are added to the duplicated Ethernet frames as it is shown in Fig 17. In the RCT section of Ethernet pairs, the Sequence number and Size fields are the same. The only field with a different value is the LAN identifier.

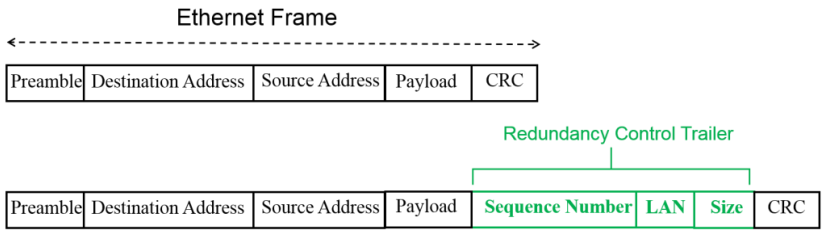


Fig 17. Ethernet frame with Redundancy Control Trailer

3.1.3.2 Routing in PRP Network

In some applications, IEDs connected to the substation LAN (designed based on PRP) need to be logically categorized into different Virtual LANs (VLANs) or IP subnets, based on their role and time-criticality. In these situations, data exchange between IEDs requires a router to forward data packets from one subnet to another. However, routing inside a PRP network is challenging. The routing challenge stem from the router operation principle. First, router checks the destination IP address of the received packet. Then, router checks its routing table to find the best matching interface for the received packet. Finally, the received packet is encapsulated for router outgoing port. In the last step, router replaces the source MAC address of the received packet with the source MAC address of

its outgoing port. This presents the challenge for PRP operation because PRP receiver node applies the original source MAC address for duplicated frame detection [75].

Therefore, other mechanisms [75][76] are required for applying PRP in IP-based communication. Examples of these mechanisms are a PRP-enabled router, PRP modification algorithms and IP Parallel Redundancy Protocol (iPRP). In PRP-enabled router, PRP should be supported either in router interfaces or tunneled by router over networks. In PRP modification algorithm, adding the original source MAC address as the new extension to RCT (in PRP frame) is proposed. Also, iPRP [76] presents a transport layer approach by replicating User Datagram Protocol (UDP) packets in parallel paths. Each packet is tagged with iPRP header containing the sequence number that is used for duplication detection. iPRP header is located after IP and UDP headers of the data packet.

3.1.4 CAN and CANopen

CAN [77] is an industrial Serial communication protocol categorized in the group of Fieldbuses. CAN supports distributed control in real-time in a robust way by broadcasting short messages to the CAN bus network. There are four types of CAN frames transmitting in the CAN bus: Data frame, Remote frame, Error frame and Overload frame. Up to 8 bytes of the application's data can be transmitted in the Data frame, although the Remote frame has no data field. The Error and Overload frames are quite similar, and they are transmitted when an error is detected in the message or the node becomes too busy.

The CAN protocol stack includes layer 1 (Physical layer) and layer 2 (Data link Layer) of OSI model. There are several application layer protocols for CAN such as CANopen [78]. CANopen adapts CAN Physical and Data link layers and operates based on Master-Slave data transmission. CANopen has its own upper application layer which presents standardized objects for process data i.e. Process Data Objects (PDO), configuration data i.e. Service Data Objects (SDO), predefined messages i.e. Special Function Objects (SFO) as well as network administration data i.e. Network Management (NMT).

PDO are used for real-time communication of inputs and outputs up to 8 bytes of data. There are two different kinds of PDO: Transmit PDO (TPDO) and Receive PDO (RPDO) for sending and receiving process data, respectively. PDO can be transmitted cyclically, or by change of state (event driven) or by polling i.e. reception of CAN request messages such as a Remote message. PDOs to be transmitted/received are specified by PDO

mapping in the Object Dictionary. SDO is for transmission of parameter data that are non-time-critical and exceed the 8 bytes' limit of PDO. There are SDO for read/write of the entries in the Object Dictionary, program download and configuring parameters. SFO are for managing synchronization and errors. NMT are first messages used to start the CAN bus and control the node operational states such as start, stop and reset.

CANopen protocol also comprises the Profile specification [78] concept that adds capability of interchangeability and interoperability to the CANopen devices. CANopen includes two types of Profile: Device and Communication profiles, which are based on the Object Dictionary (systematically arranged objects) concept in which the device-specific functions and communication mechanisms are described in the standard manner. CANopen-based communication is a good candidate for embedded control applications (such as BMS) because of its robustness and configuration flexibility.

3.1.5 IEC 62056 DLMS/COSEM

IEC 62056 DLMS/COSEM is a well-known metering protocol that can be used in a NAN. The protocol uses client-server communication and provides modeling, messaging and transporting of exchanged data between client and server [79]. DLMS/COSEM messages can be transmitted either by Serial communication or by Ethernet and TCP/UDP protocols. Device Language Message Specification (DLMS) is a general notion for abstract modeling of the communicating parties. COmpanion Specification for Energy Metering (COSEM) specifies collection of objects as the common language for metering data on top of DLMS. DLMS message contains metering data or metering function with respect to COSEM objects and data model. Similar objects form a COSEM Interface Class containing particular attributes and methods that can be accessed by xDLMS services such as Request, Response, GET (for reading an attribute) and SET (for writing an attribute). These attributes/methods must be accessed by logical name referencing includes ID of class, instance and attribute/method [80].

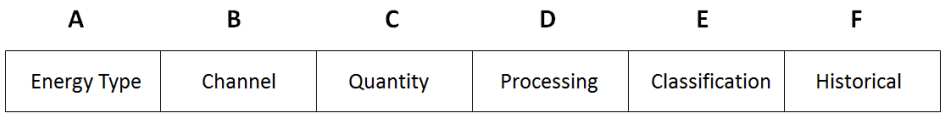


Fig 18. The OBject Identification System (OBIS) structure

Every metering data or function is uniquely represented as a code in the OBject Identification System (OBIS) [80]. This structured code is meaningful sequence of six numbers in hierarchical structure. Fig 18 shows general structure of the OBIS code.

OBIS codes are energy type specific. The first number (A) defines the energy type such as electricity or gas metering, etc. The value of B is the input number using for separating different sources. The C value denotes physical data items relating to the information source concerned. The value of group D defines the processing method for example integration. The E value is used for extra classification. The value of F is applied for historical data definition or further classification. In this way, OBIS codes provide a standard identification code for each metering data item that is exchanged between the DLMS/COSEM client (for instance MDC) and server (for example smart meter).

3.1.6 IEC Common Information Model (CIM)

The IEC Common Information Model (CIM) [81] includes multiple standards used for exchanging information between power system applications in different organizations. The main IEC CIM standards are IEC 61970 and IEC 61968, which are used for Energy Management System (EMS) and DMS in the transmission and distribution networks, respectively. IEC 61968 aims to facilitate application integration in the distribution utility companies. IEC 61968 presents a standard information model for creating the payload of the messages exchanging between DSO applications such as DMS and SCADA.

IEC 61968 standard series (parts 1-9) describes CIM object model and architecture. CIM data model is very large including high number of classes, attributes and associations. However, only subset of the CIM is required in any specific context in power system applications. Therefore, the concept of CIM Profiles [81] is introduced for every use-case in order to prevent using unnecessary parts. CIM Profile only contains necessary classes, attributes and associations requiring for the concrete implementation of the scenario.

3.2 Utility Internet for Decentralized DA

The Decentralized [8] DA architecture is very different from traditional Centralized (control center-based) architecture. In decentralized DA, accomplishing new intelligent

functions requires real-time data communication of not only control center with field devices but also between other DA components such as automation units [82] in Primary substations, field disconnectors and substations, SSAU and smart meters, aggregator and HEMS, and Data collectors with DIC.

The described communication protocols (in the previous Section) use utility Internet for communication. Utility Internet signifies an IP-based network devoted to the utility using for data exchange between DA components. A utility Internet can be a dedicated IP-based network built for the utility, or one acquired as a service from the Internet Service Provider (ISP). In Finland, ISP-based communication is the common and growing method. Fig 19 shows a utility Internet with the communication elements in red.

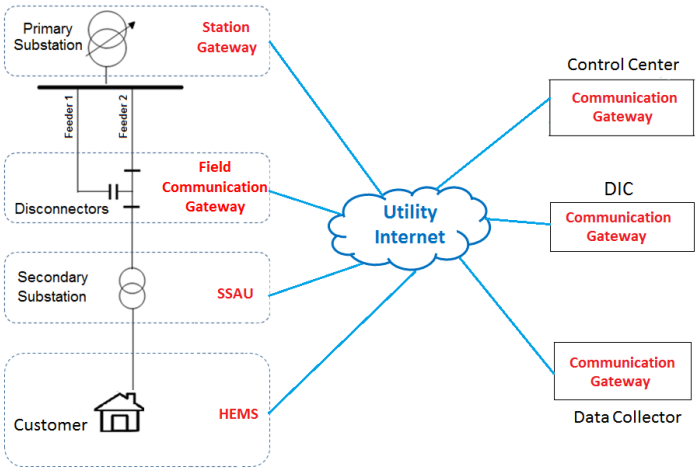


Fig 19. Utility Internet for decentralized DA data communication

Utility Internet provides better DA data manageability, broad range of network services and cost-effective method of interaction for the DA components. DA components use the utility Internet and exchange DA data according to OSI model. This model organizes network communication into seven layers. Each layer has its own protocols and adds some info to the core data, which helps the receiving node to reconstruct the original data.

Security solutions must be designed for the utility Internet in order to ensure reliable operation of DA and its subsections. Moreover, the utility Internet must meet the automation real-time requirements for the time-critical DA applications.

4 CYBER-SECURITY IN DA COMMUNICATION

DA data network is a complex network that is used for supervising, protecting, controlling and monitoring of the DA processes. DA data network includes communication within DA components as well as communication between the DA components via utility Internet. Security considerations have become essential for DA data network to ensure the efficient and reliable operation of the distribution network. Any vulnerability in DA data network could constitute a security threat [83] that malfunctions DA's operation, damage electrical devices or endanger human lives. This becomes even more vital in case of SCADA communication [84] in which hacking of SCADA data presents a serious risk that may result in significant economic losses. Thus, implementing security solutions for DA communication is not just recommended, but is mandatory. Cyber-security solutions aims to protect DA data network and utility Internet by applying a range of security protocols, technologies, devices and policies. Security in DA data communication can be methodically investigated using the security risk analysis and management process.

4.1 Risk Analysis and Management in DA Communication

The security risks could be analyzed in each DA use-case and the identified security solutions are applied. Risk level in each DA use-case is determined by assessing the associated security vulnerabilities and threats [85]. Vulnerability is a weakness in the system or a lack of a countermeasure. Threat is the potential danger of the exploitation of a system vulnerability. Risk is the probability of a threat agent exploiting a system's vulnerability and the associated consequences which could occur in the event of a security attack [85]. Security attack is any action taken against an information resource aimed at gaining unauthorized access, or destroying it. Security attacks can be divided into passive attacks (access to the system data but no change to the system resources) and active attacks (the attacker accesses the system information and changes the system resources). In DA communication, security attacks may happen at any levels such as network, communication stack, system, software, hardware, and physical levels [27][86]. Fig 20 shows the steps for the security risk analysis and management in DA data communication.

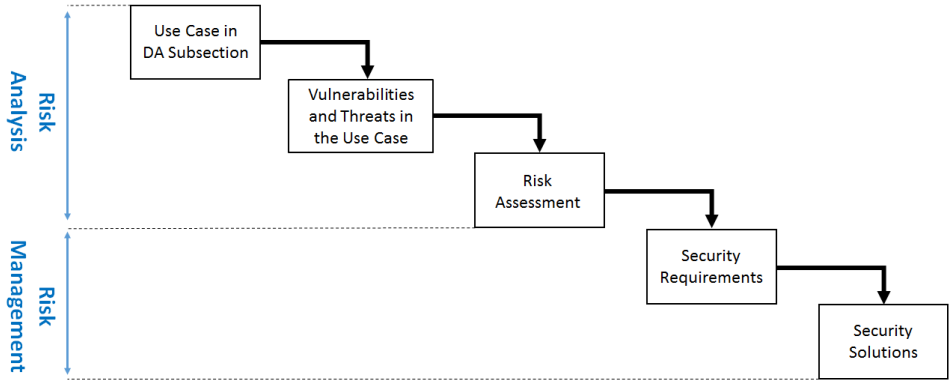


Fig 20. Framework for risk analysis and management in DA communication

The risk analysis phase investigates security vulnerabilities and identifies security threats as well as assessing the risk and likelihood of possible security attacks. Risk assessment evaluates the balance between the financial impact of the risk and the cost of mitigating it. Risk mitigation involves reducing the risk level to an acceptable enough level for the commercial operation of the business.

The risk management phase takes the outcome of Risk Assessment step and determines the security requirements for a specific use-case. Then, security solutions are proposed for risk mitigation and protecting data against different security attacks.

4.2 Security Vulnerabilities in DA Communication

In DA communication, there are security vulnerabilities in both utility Internet and data communication within DA components. In utility Internet, transmitting DA data as the plaintext (communication protocols without built-in security) may expose critical data to the passive and active attacks. Such attacks could stop distribution network operation, cause the protection system malfunction, decrease power supply quality, endanger customer privacy and damage to critical infrastructure like Smart Metering.

There are also vulnerabilities in the data networks inside DA components, which may disrupt precise functions of DA components. These vulnerabilities includes hardware, software, operating system, communication stack, and implementation flaw

vulnerabilities. Lacking a secure perimeter between DA components and utility Internet can also cause attacker penetration the private network (of DA components) from the utility Internet and gain unauthorized access to the existing resources. Furthermore, security vulnerabilities may be appeared because of the factors such as insecure network architecture, poorly defined security policies and incorrect configuration.

4.3 Risk Assessment in DA Communication

Risk assessment step systematically examines the likelihood and severity of any security attacks as well as the potential consequences of their impact on DA assets. The likelihood depends on the number and extent of the security vulnerabilities and defined security policies in DA data network. Likelihood and risk impact severities are estimated and categorized at three different levels: low, medium and high. There are several standards and frameworks applying for risk assessment such as the ISO/IEC 27005 [87], ISO/IEC 31010 [88] and NIST SP 800-30 [89]. Although these frameworks present guidelines for implementing risk assessment within organizations, they do not address the specific features of smart grid with Cyber-Physical System behavior in which security attacks could result in physical actions. This has led to much research into risk assessment methodologies and frameworks in terms of the smart grid's requirements [90]. Furthermore, Cyber Security Modeling Language (CySeMoL) [91] and P2CySeMoL [92] have been proposed as tools for system-level risk assessment in the smart grid.

4.4 Security Requirements in DA Communication

In the smart grid, security mechanisms aim to achieve [93] three primary goals: Confidentiality, Integrity and Availability (CIA). Data is protected from unauthorized access by Confidentiality, unauthorized modification of data is prevented by Integrity, and access to the data is ensured by Availability. CIA are also used as the benchmarks for determining the DA communication security requirements. In enterprise networks (like DIC) the order of security requirements is Confidentiality, Integrity and Availability. This is because in DIC the focuses are on the privacy of databases and network assets, but in the field applications (like substation LAN) the order of security requirements is different

because the focus is more on high data availability and continuous operation. In DA data communication, the priority and requirements of these security objectives depend on the particular application area in the particular subsection of DA. In some DA application areas, the real-time communication constraint has a key role in the automation system's performance. Logic Selectivity is an example of this, as blocking messages must be exchanged between the IEDs within an exact period. This suggests the utilization of the PICARD [94] model that addresses both security and automation requirements.

In addition to the above, the DA communication also requires [95] effective AAA (Authentication, Authorization, Accounting), which must be planned, designed and implemented at different levels, such as the network, application, message and user levels.

4.5 Security Solutions for DA Communication

Although information security in the field of industrial networking is still emerging, in the field of computer networking it is contained and pervasive. Since most of the industrial ICT protocols have been designed based on the OSI network layers, standard IT security protocols in OSI layers can also be applied for DA data communication. Table III describes the applicable security services [96] in the OSI layers.

Table III. Security services in the OSI model layers [96]

Security Service Description	Possible OSI Layers
Peer entity authentication	3,4,7
Data origin authentication	3,4,7
Access control service	3,4,7
Connection confidentiality	1,2,3,4,6,7
Connectionless confidentiality	2,3,4,6,7
Selective field confidentiality	6,7
Traffic flow confidentiality	1,3,7
Connection integrity with recovery	4,7
Connection integrity without recovery	3,4,7
Selective field connection integrity	7
Connectionless integrity	3,4,7
Selective field connectionless integrity	7
Nonrepudiation origin	7
Nonrepudiation delivery	7

As can be seen from Table III, most of computer networking security services operate in top layers of the OSI model. These security services can be applied for the industrial ICT standards that have included TCP/IP in their stack. However, industrial ICT standards implemented in lower layers of OSI network model (for example for GOOSE and SV) cannot directly utilize the security services that are used in the top layers of OSI model.

Moreover, state-of-the-art DA data networks (such as substation LAN) integrate [97][98] to computer networks (such as control center) by using the utility Internet. As a result, the security solutions for DA communication are no longer separated from the network security protocols utilized in computer networks. However, the impact of applying these security protocols needs to be investigated because of specific timing requirements of DA applications. Security protocols may affect the real-time behavior of DA functions, which is the main requirements in application areas such as Logic Selectivity or SAS.

The goal, therefore, is to apply IT security protocols in DA data communication in order to mitigate the security risks arising from DA environment. Achieving this goal requires a strategy. One of the most common risk mitigation strategies is the Defense-in-Depth strategy [99][100] that designs security solutions in different layers in order to mitigate the risks and minimize the probability of security attacks.

4.5.1 Defense-in-Depth Strategy

Defense-in-depth strategy can be used to secure DA data networks and its devices. Multiple security layers (physical and electronic) are embedded all over the system to provide security for data, applications and endpoints.

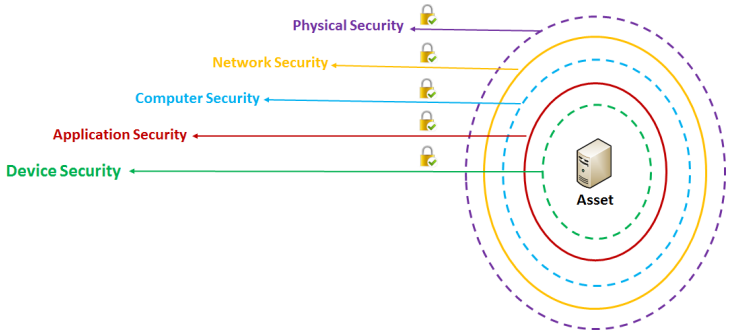


Fig 21. Defense-in-depth strategy

In Fig 21, Device Security layer provides limited access to the sensitive data. AAA mechanisms are recommended for the Application Security layer. It is proposed that Computer Security layer should use computer-hardening technologies such as antivirus software and patch management. Network Security layer protects the network communication by taking the advantage of technologies such as firewall and Virtual Private Network (VPN). Finally, Physical Security layer restricts physical access to critical areas, such as the control room or a substation, only to authorized personnel.

4.5.2 Common Security Techniques for DA Communication

This Section explains the most common IT security techniques that can also be used for securing DA data networks.

4.5.2.1 Cryptography

Cryptography techniques [105] are used to protect system against security attacks. Encryption is a cryptographic technique in which content of the messages alter by the help of an encryption algorithm, for example Advanced Encryption Standard (AES), that transforms raw (pliantext) data to unreadable (ciphertext) data by the secret key. The most common encryption method is symmetric encryption that utilizes a single secret key. The main weakness in symmetric encryption is once anyone's secret key is compromised then all of the secret keys need to be replaced. In contrast, another cryptographic technique is Public-key Cryptography that is based on asymmetric encryption by using two secret keys: public and private keys. One of the keys is used for encryption and another for decryption. The public key is made public for using others while the private key is recognized just to its owner. While the sender encrypts the message with the receiver's public key, the receiver decrypts the message by its own private key. In a case, the message origin is more important than content of the message, Public-Key Cryptography can be used in another mode: the sender encrypts the message with its private key and the receiver decrypts the message by the sender's public key. In this case, the encrypted message is called Digital Signature that proves message source identity. In Public-Key Cryptography, Security Certificates are applied in order to ensure ownership of the recipient's public key or the sender's public key.

Another cryptographic techniques is Message Authentication Code in which sender calculates an extra tag (as the function of message and secret key) for a message and

appends that to the original message. At the receiver side, recipient calculates Message Authentication Code (tag) for the received message in the same way and compares the received tag with the self-calculated tag in order to realize the message came from the authentic source. Another technique that generates Message Authentication Code is Hash function. In this technique, original message is considered as the only input for hash function. Hash function produces digest of the message, which can be considered as fingerprint of the message. The generated digest is also sent with the message and uses for the message authentication. Unlike Message Authentication Code, the hash function does not need a secret key as an input.

4.5.2.2 Virtual LAN (VLAN)

The managed [101] IE switches are the main networking elements in industrial networks such as substation LAN. The managed switch is capable of the network traffic segmentation that is a key consideration in highly time-critical DA applications like SAS. GOOSE and SV traffic should be logically segmented in order to increase data availability and satisfy the real-time requirements of SAS. VLAN is used for this purpose by segmenting data traffic in the substation LAN. VLAN is a logical broadcast domain that can span several physical LAN segments. VLAN provides security in two ways: IEDs requiring higher security are segmented into a same VLAN. In addition, although IEDs are grouped logically, their behaviors are like physically separate entities. Therefore, inter-communication between VLANs becomes possible via the use of a router. This provides router security functionalities to inter-communication.

4.5.2.3 Firewall and Demilitarized Zone (DMZ)

Firewall is a hardware or software tool that protects the private network from unauthorized access from an external network usually the Internet. All the network traffic between the private network and the Internet must pass through the firewall that examines and blocks any unauthorized traffic. Firewalls [83] should be used in DA private networks (such as substation LAN) to separate that from the utility Internet. The most common types of firewalls are packet-filtering, stateful inspection and proxy firewalls. The packet-filtering firewall operates at the Network layer of OSI model and incoming/outgoing data traffic can be filtered according to the source or destination IP addresses. The filtering mechanism is based on Access Control List file. The stateful inspection firewall uses a

dynamic state table for storing information about the data packets. Each packet has source and destination connection information that are stored in the state table and this information in combination with some defined rules are used to allow or block the communication. The Proxy firewall operates at the Application layer of OSI model. This firewall is capable of controlling the applications or services specifically.

DMZ [102] is applied when more secure architecture is required for separating a private LAN from the Internet. DMZ is usually implemented with dual firewalls and only the resources that need to be reachable from the Internet are located in the DMZ, while rest of the LAN remains inaccessible from the Internet. A possible place for DMZ implementation is in DIC in which all the databases are located in the Intranet behind the DMZ. Remote access to DIC databases is only allowed via the intermediary gateway located inside DMZ. This eliminates direct remote access to DIC from the utility Internet.

4.5.2.4 Virtual Private Network (VPN)

VPN is a private network solution for secure data transmission over an untrusted network such as utility Internet. Its operation is based on the tunneling protocols and security mechanisms like encryption and authentication. Tunneling standards operate at different layers of the OSI model. The secure tunnel is established by encapsulating and encrypting of data before transmission over the untrusted network. Data communication is invisible for all the nodes in the network except for those that have VPN secret key. There are two common types of VPN: Remote-Access and Site-to-Site. The Remote-access VPN allows remote individuals to create secure tunnel to the private network such as a Company's Intranet. The Site-to-site VPN allows interconnection of entire network (multiple users) to the main company network over the Internet. Site-to-site VPN can be used for securing Internet communication between the control center and the substation networks.

5 RESEARCH METHODOLOGY AND MATERIALS

This section describes the environment and equipment that were used for building, modeling and simulating different DA functions and verifying the security solutions.

5.1 Smart Grid Testbed

The smart grid DA testbed is located in the Laboratory of Electrical Energy Engineering at Tampere University of Technology. The testbed is used for examining smart grid functions like protection, monitoring, control, and communication. The testbed consists of various hardware and software components such as real-time network simulator, commercial IEDs, SSAU, software tools, data networking and cyber-security equipment.

5.1.1 Real Time Simulation of the Distribution Network

Although the focus of this research work is on data communication, distribution network simulation is also required for accomplishing some projects. For instance, real-time distribution network simulation is necessary for testing Logic Selectivity in [P5]. Real Time Digital Simulator (RTDS) [103] was used for simulating the distribution network components such as circuit breakers, switches, transformers, MV feeders and busbars. RTDS consists of processor cards for network simulation and input/output cards for both digital and analog signals: digital input, digital output, analog input and analog output. RTDS simulates the electrical network model in real-time and this makes it possible to connect actual IEDs to RTDS for hardware-in-the-loop simulation [104]. IEDs typically receive network voltage/current from analog output card. Moreover, digital output/input cards are applied for status/command signals from/to the simulated model in RTDS.

5.1.2 Automation Devices for Experiencing DA Functions

Testbed includes several type of IEDs such as feeder automation IED, protection IEDs, Station Gateway and SSAU. These devices not only support electrical functions but also communication protocols. These IEDs were used for building the lab setups for Logic Selectivity, substation and feeder automation. Furthermore, HEMS, BMS and smart meter were utilized for analyzing customer automation functions and Smart Metering.

5.1.3 Remote Monitoring and Control of the Distribution Network

One of the advantages of creating communication between the distribution network elements is remote monitoring. SCADA is used for remote monitoring and control of the distribution network. IEC 104 Master and OPC UA client applications were applied in order to represent control center SCADA in our research work. These applications exchange relevant data with the IEDs and other automation devices over the Internet.

5.1.4 Internet for Data Communication

The smart grid testbed also includes data networking devices for creating DA data communication over the Internet. Examples of IE switches, routers, 3G/4G modem, PRP devices and security gateway. The Internet service was provided from university research and development network (TUT RDNet) and Finnish mobile network operator (Elisa).

5.2 Software Tools and Application Development

The software tools from different manufacturers were used for configuring the IEDs, smart meter, automation and data networking devices in the laboratory environment. Furthermore, some software applications were also developed in order to implement the proposed solutions for the information integration as well as creating secured messages for DA communication. These developed applications used software toolkits such as OpenSSL, Java TLS libraries, PCAN-Basic API and IEC61850 MMS libraries.

5.3 Utilization of Test setups for Cyber-Security Studies

There are different test setups created in order to build different use-cases and analyze data communication in various DA functions. The test setups contain the above-mentioned automation devices, the aforementioned monitoring applications and electrical network simulation in RTDS. In every test setup, accomplishing DA functions requires data communication over IP-based network, mostly the Internet. Communication security was investigated and security solutions were proposed by adding security protocols (SSL, TLS, PPTP, IPsec and OPC UA security) to the data communication.

6 SECURITY SOLUTIONS ENSURING DA FUNCTIONS

Cyber-security solutions are proposed for the use-cases taken from the following DA functions: substation automation, feeder automation, Logic Selectivity, customer automation and Smart Metering. In each use-case, the issue of security is studied with respect to the depicted steps in Fig 20 (use-case, security vulnerabilities, security requirements and security solution) except the risk assessment step that is out of the scope of this dissertation. Lastly, final security analysis is performed for each use-case in order to analyze how the proposed security solution satisfies the use-case security requirements.

6.1 Smart Grid DA Function 1: Substation Automation

In Primary substation, SAS provides automation functions at both the substation and the distribution network levels.

6.1.1 Primary Substation – SAS Local Communication

Modern SAS uses a substation LAN and IEC 61850 for the local data communication.

6.1.1.1 Use-Case: Local Monitoring in IEC 61850-based Substation

An IEC61850 substation is modeled with RTDS, real IEDs and software applications.

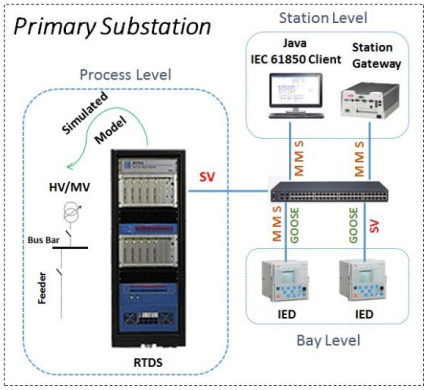


Fig 22. Lab setup for modeling an IEC 61850-based Primary substation

In Fig 22, substation LAN contains Process, Bay and Station level devices that communicate via IE switch to accomplish Horizontal and Vertical communications that was explained in Section 3.1.2.2. The communication details and contents of the messages are explained in [P6]. An IEC61850 MMS client application is developed in Java, and is installed in the substation computer. This MMS client functions as the substation local monitoring software that is capable of requesting the data values from the MMS servers in the IEDs.

6.1.1.2 Security Vulnerabilities

In the substation LAN, there are security vulnerabilities in all the substation levels. The lack of SV in Process level stops protection IEDs functioning. Moreover, attacker could generate spoof SV to cause the protection functions in the IEDs to malfunction. At Bay level, fabricated GOOSE messages may lead to undesired outages and damage to the electrical components. At Station level, an unauthorized IEC61850 client could send fake MMS commands to the IEDs. Moreover, transmitting raw messages in the substation LAN increases the risk of eavesdropping, traffic analysis and cyber-attack to IEDs.

Furthermore, there is a vulnerability in the network design of the substation LAN. Any failure in IE switch or device connections to IE switch leads to unavailability of data in the whole or part of the substation LAN. This could stop the substation from functioning.

6.1.1.3 Security Requirements

In substation LAN, the order of security requirements [27] is first Availability, next Integrity and lastly Confidentiality. Availability is the most important requirement because the continuous operation and correct functioning of SAS depends on the availability of data. Substation data, in particular measurement (SV) and protection (GOOSE) data should be readily available in the substation LAN that has reliably designed in a robust way to minimize service downtime. The second most important security requirement is Integrity that ensures authenticity of the substation data exchanging between substation devices and applications. Finally, confidentiality is required to protect substation data, especially critical data, from unauthorized access.

6.1.1.4 Security Solution

In [P6], designing PRP networks and secured messages by TLS are proposed as the security solutions for the substation LAN. As stated above, data availability is the most important security requirement. A solution to increase data availability is network redundancy. In the lab setup (Fig 22), two PRP networks are designed for the substation LAN in order to increase data availability. PRP network 1 includes devices in Process and Bay levels. PRP network 2 contains Station level devices. In the lab setup (Fig 22), all the devices are DANs except RTDS and substation computer (IEC61850 client) that are SANs and connect to their respective PRP networks via Redundancy Boxes (PRP modules) that was explained in Section 3.1.3.

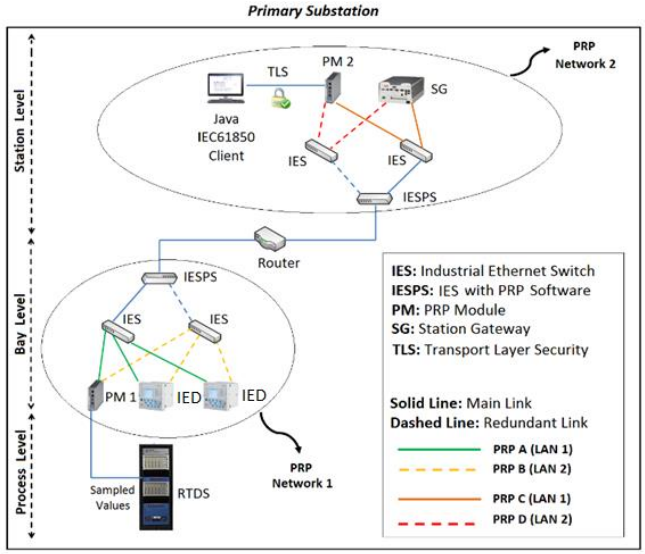


Fig 23. PRP networks design for high data availability

In Fig 23, two PRP networks are designed due to routing challenges in PRP network that were explained in Section 3.1.3.2. Router connects to two PRP networks via the IE switch with PRP Software. This switch supports PRP protocol and has two parallel Ethernet ports that are attached to the regular IE switches in each PRP network.

Integrity and confidentiality are achieved via TLS that is proposed to secure substation local communication, particularly substation local monitoring by IEC61850 client.

However, TLS is not supported by the Bay level IEDs. This brings the idea of using Station Gateway in the middle of communication because it is an industrial computer with embedded Microsoft Windows, which has more possibilities for implementing security protocols. The proxy server supporting TLS and MMS is programmed, and is proposed for securing communication in the substation Station level.

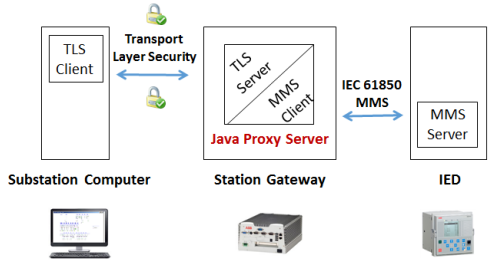


Fig 24. Secured messages for the substation local communication

The proxy server is placed in the Station Gateway between the TLS client and the MMS server, as illustrated in Fig 24. All the exchanged messages between the substation computer and the Station Gateway are secured by TLS, providing not only communication confidentiality and integrity but also preventing the unauthorized access of other clients to the Proxy server. The structure of the exchanged data frames between substation computer and Station Gateway is depicted in [P6].

6.1.1.5 Final Security Analysis

This Section analyzes how the proposed solutions in the previous Section provide the security requirements mentioned in Section 6.1.1.3.

Availability: In Fig 23, all the PRP devices (DANs) and PRP modules run LRE software, as was explained in Section 3.1.3.1. On the sender node, LRE duplicates messages before sending them to two LANs (LAN 1 and LAN 2) in accordance with the data frame format depicted in Fig 17. On the receiver side, LRE ignores the duplicated frame by inspecting the RCT in the data frame. In cases of communication link or IE switch failures, data will be automatically available from the backup LAN with zero recovery time.

Table IV briefly explains the stages [105] that occur to create integrity and confidentiality (by TLS) for data communication between substation computer and Station Gateway.

Table IV. Secure session establishment between the TLS Client and Proxy Server

Stage	Sub-Stage	Description
TLS Handshaking	Establish Security Parameters	TLS client initiates the session with a message that contains supported security parameters by the client.
		Proxy server responds with the message that consists of security factors like TLS version and key exchange method.
	Server/Client Authentication and key Exchange	Proxy sends its security certificate to the TLS client and asks for client security credentials.
		Proxy server authentication.
		Client sends security credentials to the Proxy.
		Client authentication.
		Simultaneous generation of the session keys by client and proxy.
	Finalization	Client sends the message and verifies successful operation of key exchange and authentication.
		Proxy replies by sending the message that implies Handshaking stage is accomplished, and application data can be securely exchanged by applying the generated session keys.
TLS Record Protocol	Fragmentation	Fragmentation of messages to manageable blocks of bytes.
	Compression	Data block compression using the compression method selected during the Handshaking stage.
	Add Message Authentication Code	Adding Message Authentication Code value by applying the generated session keys.
	Encryption	Message encryption by using the generated session keys.
	Record Header	Append TLS record header and transmit secured message.

Integrity and Confidentiality: TLS record protocol uses the session keys (generated during Handshaking) in order to add Message Authentication Code and encrypt substation data for providing integrity and confidentiality, respectively. Moreover, server and client authentications enhances the integrity by exchanging server X.509 security certificate and client password. As a result, only authenticated clients in the substation LAN are allowed to access substation data in the proxy server.

6.1.2 Primary Substation – SAS Remote Communication

Modern SAS has a utility Internet for the remote data communication. There are several standards for the substation remote communication to the control center.

6.1.2.1 Use-case: Remote Monitoring in IEC 61850-based Substation

In the lab setup (Fig 22), substation also communicates with the control center for remote monitoring and control. Modern substation uses Station Gateway for exchanging data with the control center via the utility Internet. Station Gateway has more capabilities than a typical RTU, and supports various communication protocols to the control center.

The most common substation remote communication protocols are IEC 60870-5-104, IEC 61850, DNP3 and Modbus-TCP. These protocols have no internal security mechanisms. In [P2], IEC 62541 OPen Connectivity Unified Architecture (OPC UA) is proposed for the substation remote communication, as is shown in Fig 25, because it can create secure and interoperable communication.

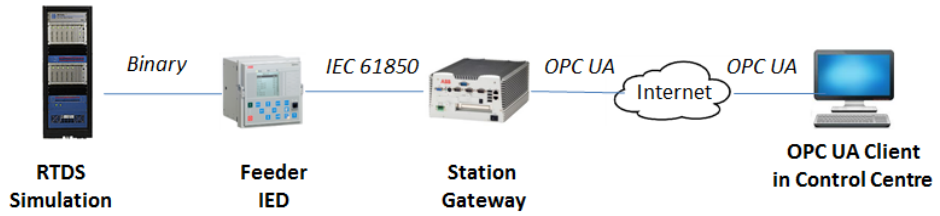


Fig 25. Primary substation remote communication

In Fig 25, substation remote communication is tested by transmitting the position (OPEN/CLOSE) of the simulated breaker (in RTDS) to the remote OPC UA client application. First, RTDS sends the position of the breaker to the feeder IED as a binary signal. Then, the feeder IED defines this binary data with respect to IEC 61850 data model as it is explained in [P2]. Next, the feeder IED performs Vertical communication and transmits the denoted IEC61850 dataset (*REF615.CTRL.CBXCBR1.pos.stVal*) to the Station Gateway. Finally, the Station Gateway should deliver this dataset to the remote OPC UA client that functions as the substation remote monitoring software.

The Station Gateway supports classic OPC (OPC DA) and provides OPC DA server for the IEC 61850 dataset. However, the Station Gateway has no support for OPC UA. Therefore, adding OPC UA Wrapper [106] functionality to Station Gateway is proposed. The OPC UA Wrapper application is installed in the Station Gateway, and makes the Station Gateway capable of OPC UA communication to the control center.

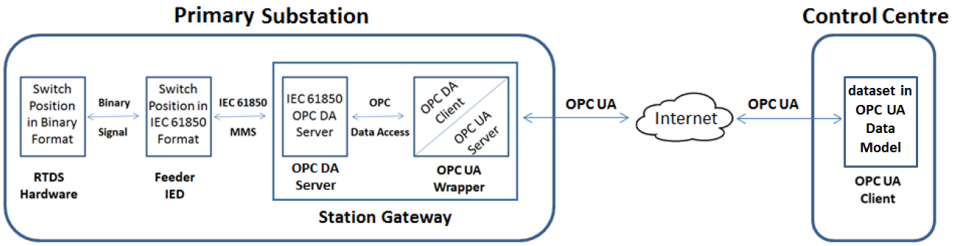


Fig 26. OPC UA for substation remote communication to control center

Fig 26 shows the communication components in substation remote communication. The wrapper functions as both OPC DA client and OPC UA server. The Wrapper presents the IEC 61850 dataset in the OPC UA information model that can be requested by UA client.

6.1.2.2 Security Vulnerabilities

There are security vulnerabilities in the remote communication if substation data is sent as the OPC UA without security. Network eavesdropping is a vulnerability in which an unauthorized attacker captures OPC UA communication traffic. The attacker is able to conceal substation events from the control center, modify the exchanged data, and send forged commands to substation devices by impersonating control center personnel.

6.1.2.3 Security Requirements

In the substation remote communication, the security requirements order [5] is Integrity, Availability and Confidentiality. Integrity is the most important requirement and is especially essential for the control commands sending from the control center to substation. Availability is highly critical for control commands and less critical for monitoring data. Confidentiality is the last security requirement.

6.1.2.4 Security Solution

In [P2], secured messages by OPC UA security model is proposed for protecting substation remote (Internet) communication. OPC UA contains the in-built security model that administers security functions in the different layers: Application layer, Communication layer and Transport layer in each of which there is provision for certain security mechanisms, as shown in Fig 27. These security layers [107] provide security mechanisms not only for integrity, confidentiality and availability but also for

authentication and authorization. Secure session is created between UA client and server (Wrapper) once a secure channel for data transmission has been established between them.

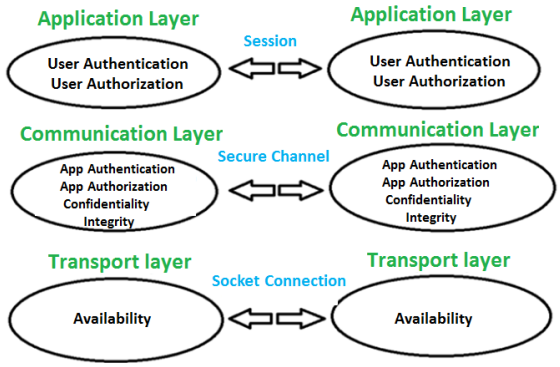


Fig 27. The OPC UA security [107] model

OPC UA security provides security in the Application layer of OSI model. Although OPC UA security model is robust, it is also recommended that security should be applied in the communication path level in case of any possible faults occurring during the OPC UA stack implementation. In this regard, Publication 6 [P6] also evaluates communication path security by testing two types of VPN: Internet Protocol Security (IPsec) [110] and Point-to-Point Tunneling Protocol (PPTP) [111]. While the VPN solution provides point-to-point security over the Internet, the secure OPC UA provides end-to-end security between the applications as illustrated in Fig 28. Moreover, firewalls are also used to control incoming/outgoing traffic from/to Internet.

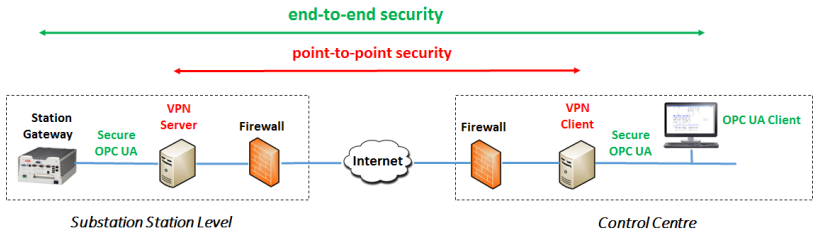


Fig 28. Security for the substation remote communication

The security mechanisms of the above-mentioned VPNs and OPC UA are compared in details in [P6]. Table V briefly shows the comparison of the security mechanisms.

Table V. Comparison of security in the substation remote communication

	Confidentiality	Integrity	Availability	Authentication	
				Application/Device Authentication	User Authentication
IEC 104	---	---	✓	---	---
OPC UA	✓	✓	✓	✓	✓
PPTP	✓	---	---	---	✓
IPsec	✓	✓	---	✓	---

A high level of security is achieved by applying secure OPC UA along with IPsec, which provide security at the message level and the communication path level, respectively. The structure of the secured OPC UA messages within IPsec tunnel is shown in the [P6].

6.1.2.5 Final Security Analysis

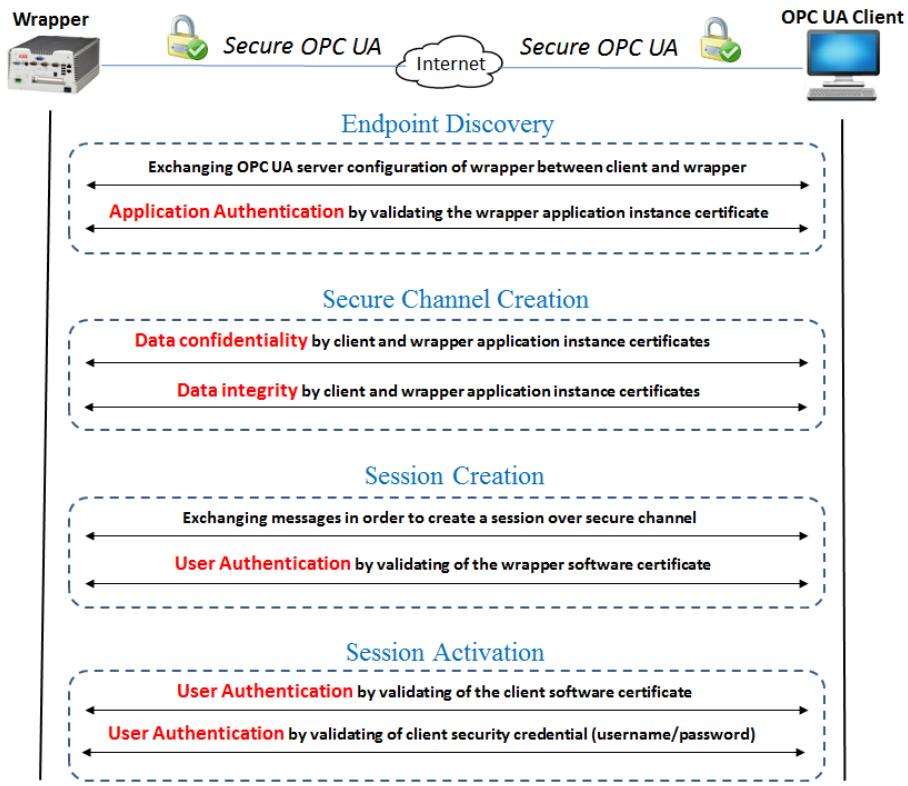


Fig 29. Secure connection establishment between substation and control center

Fig 29 summarizes the actions that occur during secure OPC UA communication, which provide the remote communication security requirements declared in Section 6.1.2.3.The secure OPC UA communication is established in four [107] stages: endpoint discovery, secure channel creation, session creation and session activation. Each stage includes specific OPC UA messages and security credentials which are explained in detail in [P2].

Integrity and Confidentiality: the Communication layer of the OPC UA security model provides data integrity and confidentiality during the Secure Channel Creation stage. OPC UA provide strong integrity and confidentiality by the security policy Basic256Sha256 [108] profile in which security algorithms apply Sha256 for the signature digest and 256-bit encryption. This security policy requires Public Key Infrastructure that was explained in Section 4.5.2.1. Both UA client and UA server contain a pair of security keys that are used for signing and encrypting the transmitted messages between the UA client and server (Wrapper). In addition, OPC UA security provides application authentication and user authentication by exchanging certain X.509v3 certificates (Application Instance Certificates), software certificates and username/password.

Availability: The transport layer of the OPC UA security model provides availability by transmitting the secured data through the socket connection in which error recover mechanisms retain the availability of the services.

6.2 Smart Grid DA Function 2: Feeder Automation

Feeder automation is a subsection of DA, which improves distribution network reliability. Modern feeder automation approaches apply RTUs/IEDs interacting via utility Internet.

6.2.1 Use-Case: Decentralized Feeder Automation

Section 2.3.3 introduced Decentralized feeder automation approach in which automation decisions are made by the agent software locating in Primary substation. Publication 4 [P4] proposes the use of CPS as the place for the agent software. In Primary substation, CPS is applied as the backup protection for the substation protective IEDs. CPS is located at the Station level and used for lesser time-critical protections such as high-resistance earth faults [28][29] and circuit breaker condition monitoring. In CPS, the agent software

has access to the substation feeders' data and makes intelligent decisions for Decentralized feeder automation. In fact, the agent distributes DMS functionality to Primary substation level. This corresponds the decentralized DA and increases distribution network reliability by shifting the location of the decision–making element from the central place (control center) to the distributed locations (Primary substations). However, executing the agent decisions requires real-time communication between the Primary substation and in-field disconnectors.

The agent communicates with in-filed disconnectors by cooperating with an additional software module (for example IEC 104 master in Primary substation SCADA) that executes feeder automation decisions. Fig 30 illustrates a communication architecture for Decentralized feeder automation approach, as is explained in [P4].

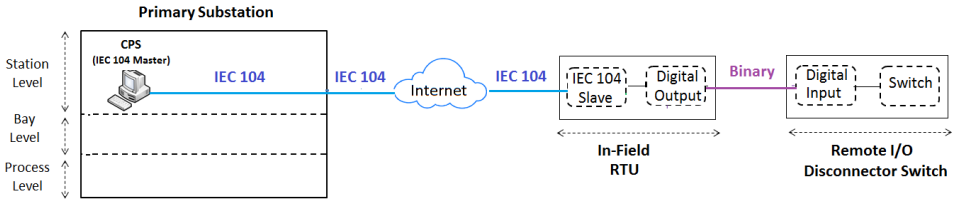


Fig 30. Communication architecture for Decentralized feeder automation

IEC 104 is used as the communication protocol between Primary substation and in-field RTU. IEC 104 master application executes Decentralized feeder automation decisions, for example remotely open/close the disconnector switch that is simulated in RTDS. The IEC 104 message containing open/close command is sent from CPS to the in-field RTU. This message activates the digital output of RTU and subsequently the attached digital input terminal of RTDS, which controls the switch disconnector position.

6.2.2 Security Vulnerabilities

IEC 104 has no internal security mechanisms for securing the Internet communication in Decentralized feeder automation. The plaintext IEC 104 messages could be captured and subversive electric outages may occur through unauthorized applications sending forged IEC 104 commands to the in-field RTUs. This cause malfunctioning of the field-disconnectors and unwanted outages in the MV feeders.

6.2.3 Security Requirements

In feeder automation, the most critical requirement [5] is Integrity, next Availability (high-critical for control and less-critical for monitoring) and then Confidentiality.

6.2.4 Security Solution

In [P4], IPsec in Tunnel mode with Encapsulating Security Payload (ESP) is proposed to create a secure communication path for exchanging feeder automation messages over the Internet. Cellular communication, for example 3G, is being considered as the preferred technology for Internet communication in Decentralized feeder automation. Therefore, the Field Communication Gateway is required. This device supports not only the Internet technologies (3G router) but also security technologies (integrated firewall and IPsec).

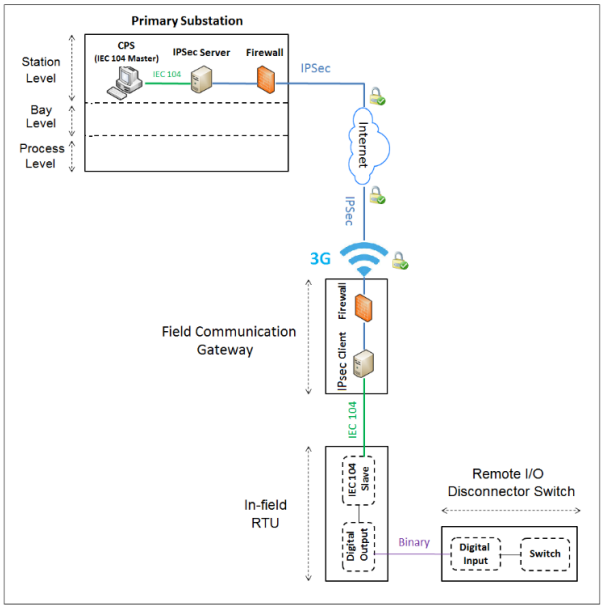


Fig 31. Secure communication path for Decentralized feeder automation

Fig 31 shows the secure architecture that is proposed. IPsec provides certificate-based authentication for IPsec peers (field gateway and substation) and cryptographic security for integrity and confidentiality of IP data (feeder automation messages). The structure of the IEC 104 messages wrapped and secured in the IPsec tunnel is presented in [P4].

6.2.5 Final Security Analysis

In the following, it is explained that how IPsec creates secure communication path for IEC 104 messages and provides the security requirements mentioned in Section 6.2.3. Internet Key Exchange (IKE) and ESP are the main components of IPsec tunnel establishment. IKE includes two phases operating for negotiating security policies and generating a secret key, respectively. IPsec tunnel is stablished after successful authentication of IPsec client and servers by exchanging security certificates during phase one of IKE. The second phase of IKE applies Diffie–Hellman key exchange in which a secure channel is established between IPsec peers by generating a shared key that is used for securing communication. ESP provides cryptographically-based security for IP data.

Integrity: ESP in Tunnel mode [109] provides data integrity for the IP packets by signing the portion of IP packet including the IP payload that contains IEC 104 messages. Furthermore, ESP provides data source authentication by the hash algorithm and using the shared secret key. The authentication data are placed in the ESP Authentication Trailer that is appended to the IP packet. IPsec peers (in the substation and Field Communication Gateway) calculates the hash value in order to verify the identity of the sender.

Confidentiality: The ESP trailer is added to the IP packet before encryption happens. Then, the data after the ESP Header and before the ESP Authentication Trailer is encrypted by the encryption algorithm that is specified during the Security Association establishment in the phase one of IKE. The IEC 104 messages are also included in the encrypted section of the IP packet.

Availability: IPsec has not specific mechanisms for data availability. However, Field Communication Gateway has support for the second SIM card that can be used for a redundant 3G connection in order to maximize network availability.

6.3 Smart Grid DA Function 3: Logic Selectivity

DSO employs Logic Selectivity to reduce both the number of outages and their durations. Consequently, reliability indices such as SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) are improved.

6.3.1 Use-Case: GOOSE-based Logic Selectivity

An example of GOOSE-based Logic Selectivity algorithm was explained in Section 2.3.2.

6.3.1.1 Algorithm Testing by Hardware-in-the-Loop Simulation

Fig 32 depicts the lab setup that is used for testing the GOOSE-based Logic Selectivity algorithm that was presented by Fig 8. Test setup is an example of the hardware-in-the-loop simulation in which the distribution network is simulated in RTDS and actual IEDs are externally connected to the RTDS. Every IED is attached to one of the simulated substations by connecting to the analog terminals (for receiving measurements) and digital terminals (for controlling circuit breaker/switch position) of RTDS.

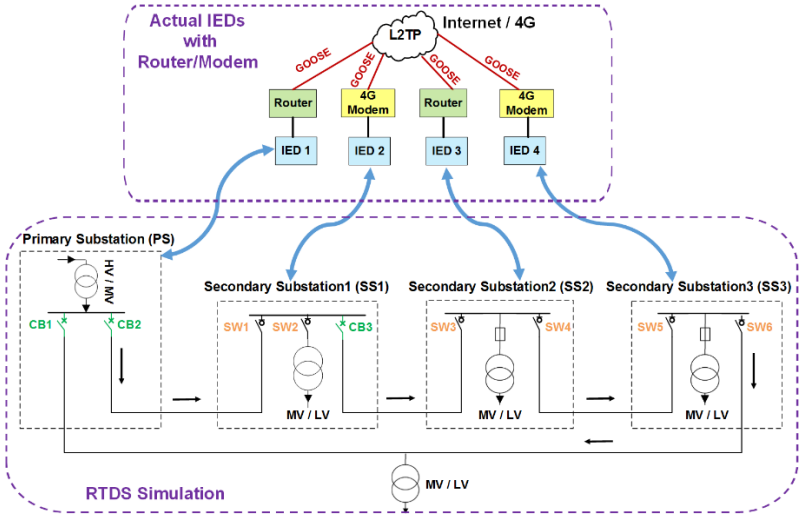


Fig 32. Lab setup for testing the GOOSE-based Logic Selectivity algorithm

The Logic Selectivity algorithm is defined by ISaGRAF, and is embedded into the IEDs. The IEDs support all the applied [P5] IEC61850 LNs for the algorithm. Regarding to the algorithm, IED1 is CB IED. While IED3 and IED4 are SW IEDs, the IED2 functions as both SW IED (to control the switches) and CB IED (to control the circuit breaker).

The content of the GOOSE blocking messages are defined for the IEDs as a SCL file that was mentioned in Section 3.1.2.2. GOOSE subscription between IEDs is designed based on the direction of the power flow and location of each IEDs in this direction. Power flow

direction is from Primary toward Secondary substations. Thus, every upstream IED subscribes to the published GOOSE messages by downstream IEDs, as described in [P5].

GOOSE messages are exchanged between IEDs via utility Internet. GOOSE messages are OSI model layer 2 messages and there are challenges in transmitting them over an IP-based network. In [P5], Layer 2 Tunneling Protocol version 3 is proposed for this purpose. Therefore, IED connect to the Router/4G modem that has support for this protocol.

6.3.1.2 Algorithm Performance Evaluation

The simulated network is run in RTDS, which is monitored and controlled by the RSCAD [103] software. All the breakers and switches are normally closed except the CB1 that is normally open (backup feeder). Investigating the Logic Selectivity algorithm performance requires simulating a fault in the simulated network and examining the behavior of the attached IEDs. Therefore, the fault logic is designed in RSCAD. The fault logic is capable of simulating various fault categories (Phase/Phase-Phase/Three-Phase overcurrent) and different fault types (temporary and permanent) at diverse locations of the simulated model.

The algorithm performance is evaluated by simulating different faults while we have real-time monitoring of the distribution network elements in RSCAD. Fig 33 demonstrates one example in which the algorithm functionality was tested for the permanent (5sec duration) three-phase short-circuit over current fault between SS2 and SS3 in the simulated network of our test setup.

After simulating the fault (step1 in Fig 33), IEDs detect the fault and Logic Selectivity algorithm is started. The first stage of the algorithm is accomplished by CB IEDs opening the nearest CB to the fault location i.e. CB3 that is opened (step2 in Fig 33) by its attached CB IED2. The algorithm includes two reclosing times: fast reclosing (R1=300ms) and slow reclosing (R2=30sec) designed for temporary and permanent faults, respectively. In this test, the opened CB3 is reclosed (step3 in Fig 33) by CB IED2 after passing the fast reclosing time. CB3 is reopened (step4 in Fig 33) since the fault is permanent (5sec duration). Then, the second stage of the algorithm operates by SW IED3 that opens (step5 in Fig 33) the nearest SW to the fault location, i.e. SW4. Finally, CB3 is reclosed after passing the slow reclosing time for restoration. This last step is not shown in Fig 33 because Time Axis only shows real-time values for 3 seconds.

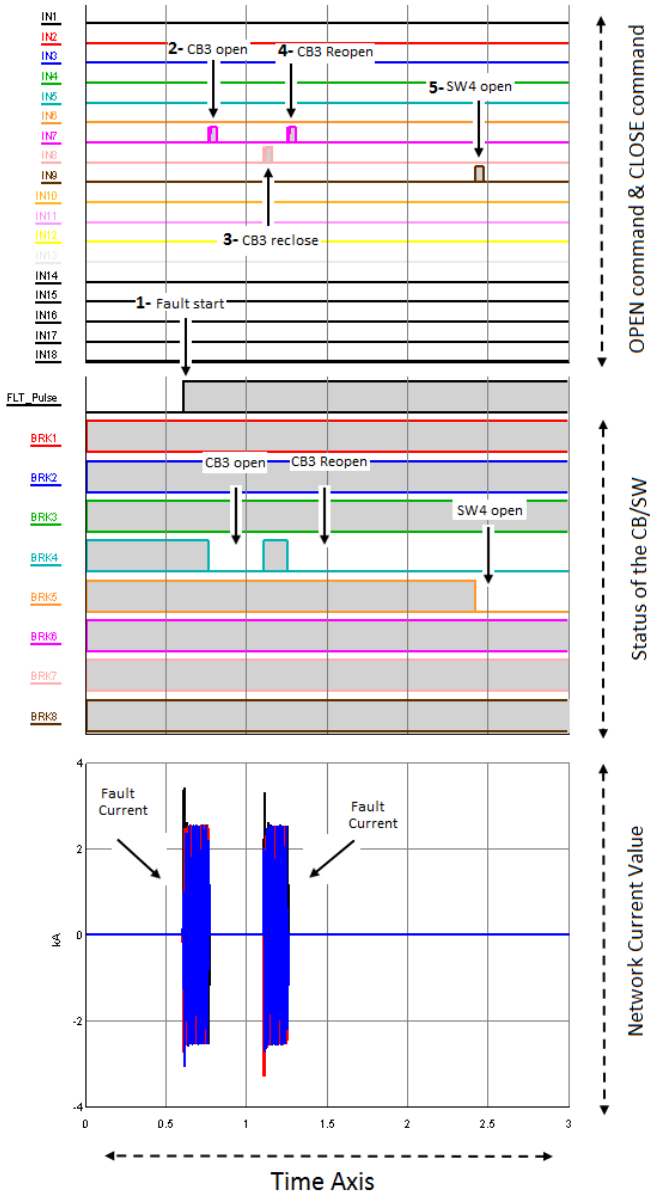


Fig 33. Real-Time network monitoring for the permanent fault between SS2 and SS3

As stated above, the IEDs behaves Selectively i.e. closest CB IED and SW IED to the fault location are operated. For instance in the first stage of the algorithm, both CB IED1

and CB IED2 detect the simulated fault. However, only CB IED2 sends trip command to open its attached circuit breaker (CB3). Fig 34 depicts the operation times of CB IEDs in our test i.e. simulating a fault between SS2 and SS3.

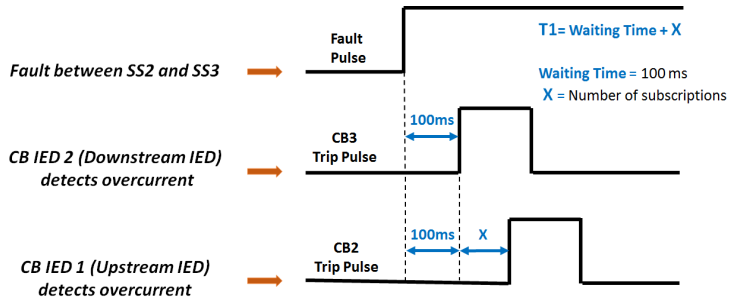


Fig 34. The operation times of CB IEDs in the first stage of the algorithm

During fault condition, both CB IED1 and CB IED2 detect the fault current, start publishing GOOSE messages and wait for passing the T1 before issuing the trip commands. In T1 formula, the Waiting Time is 100ms in our test. The number of GOOSE subscription to each CB IED determines the X value. This X value causes Selective operation of CB IEDs. For example, if 50ms is considered for every subscription then the value of the X is 1*50ms (T1=100ms+50ms) for CB IED1 because it only subscribes to the published GOOSE messages by CB IED2 that is the only downstream CB IED after that in the network. However, CB IED2 is the most downstream CB IED in the network and there is no CB IED after that. Consequently, no GOOSE subscription has been configured for that and X is equal to zero (0*50ms) in CB IED2. This results in smaller T1 value (100ms+0) for CB IED2 that Selectively issues trip command before CB IED1.

To conclude, CB IEDs make Selective decisions by detecting fault currents as well as receiving GOOSE from downstream CB IEDs during Waiting Time. The protection operation in CB IED1 is blocked because the published GOOSE message by CB IED2 is received to CB IED1. The important point here is CB IED1 operation is blocked only if the published GOOSE message (by CB IED2) is received during Waiting Time (100ms). Otherwise, T1 value is not increased in CB IED1, and both CB IED1 and CB IED2 will have the same T1 value (100ms+0) and simultaneously operate and open both CB2 and CB3. In such a case, the algorithm operation is not Selective. This concept is same for the SW IEDs but they operate based on fault passage indication instead of fault detection.

6.3.1.3 Algorithm Timing Evaluation

In RSCAD, the algorithm operation times are calculated in order to compare theoretical results with experimental outcomes by IEDs. The applied IEDs for testing the algorithm are prototypes from Schneider Electric, which were tested in our Smart Grid Testbed.

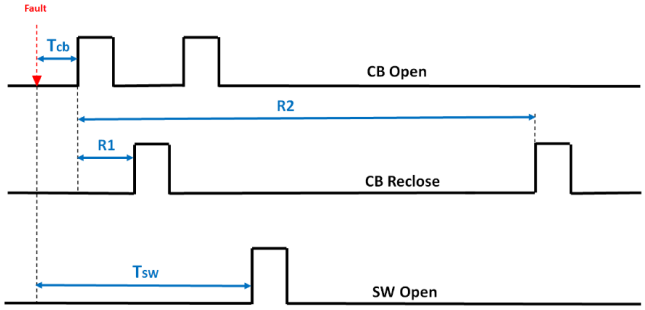


Fig 35. The operation times in the GOOSE-based Logic Selectivity algorithm

The operation times (Fig 35) were analyzed for the three stages of the algorithm: Tcb (time of fault isolation by CB IED), Tsw (time of further isolation by SW IED) and restoration times (R1 is fast reclosing and R2 is slow reclosing). These operation times were analyzed by performing 10 tests in which different faults are simulated in RSCAD and the operation times are calculated. Fig 36 shows the results for the 10 tests.

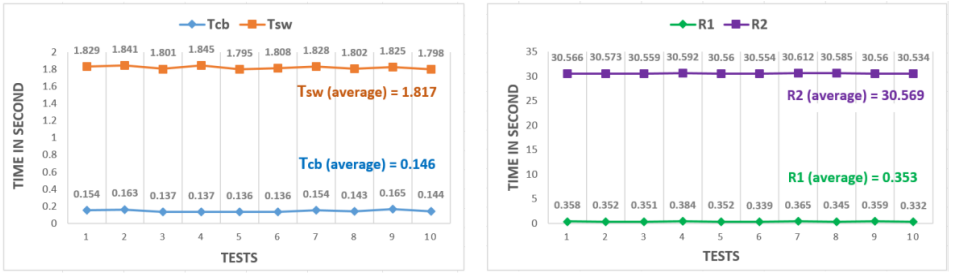


Fig 36. The calculated operation times in the ten times tests

In Fig 36, some delays were added to the operation times in each test. For example, Tcb is not exactly equal to T1 (100ms+0). These delays are related to the overcurrent confirmation by the IED, which starts the algorithm, and delay created by cycle timing of ISaGRAF. However, the testing results still meet the requirements for the application.

6.3.2 Security Vulnerabilities

In GOOSE-based Logic Selectivity, unauthorized applications may capture data traffic and publish fabricated GOOSE blocking messages to overload the IEDs subscription to the messages. This can also cause malfunctioning of the algorithm and subsequently unwanted operation of circuit breakers or switches.

6.3.3 Security Requirements and Automation Requirements

Both security requirements and automation real-time requirements must be satisfied in order to ensure accurate GOOSE-based Logic Selectivity performance.

6.3.3.1 Security Requirements

The security requirements are first Integrity (in order to ensure GOOSE messages are genuine and not altered in transit), then Availability (access to GOOSE messages should be ensured when they needed), and finally Confidentiality (in order to prevent unauthorized access to GOOSE messages content).

6.3.3.2 Automation Real-Time Requirements

According to the Logic Selectivity algorithm, precise performance of algorithm requires the exchange of blocking messages between substations strictly within the Waiting Time. In other word, real-time communication has a significant role in the successful operation of the automation system. Logic Selectivity is a hard real-time automation system because receiving the GOOSE blocking message after the deadline (Waiting Time) is not useful and leads to fail operation of the algorithm. In [P5], the Logic Selectivity algorithm with T1 value of 100ms is tested. Therefore, the communication network must be capable of transferring GOOSE messages between the IEDs within 100ms.

Accordingly, Logic Selectivity requires both secure and real-time data communication. These requirements can be identified together by utilizing PICARD model.

6.3.3.3 PICARD Requirements

PICARD [94] model addresses both security (Privacy, Integrity, Confidentiality) and automation (Alarm, Real-Time, auDiting) requirements in an automation system. In PICARD model, Alarm is hard real-time requirement, Real-Time is cyclic

communication timeliness requirement, and auDiting is the security audit requirement. In Logic Selectivity, the most important security requirement is Integrity. The most important automation requirement is Alarm because of the hard real time requirement. Confidentiality is the second most important security requirement.

6.3.4 Security Solution and Automation Solution

In the following, both security solution and automation real-time solution are explained for the GOOSE-based Logic Selectivity.

6.3.4.1 Security Solution

The applied Router and 4G modem support L2TPv3 [112] that tunnels GOOSE messages between substations. L2TPv3 in itself is a VPN solution with no encryption or strong authentication. Thus, security must be added via the use of other protocols. In [P5], L2TPv3 over IPsec [110] in Transport mode is proposed to create a secure communication path for exchanging GOOSE blocking messages over the Internet. IPsec creates secure communication path in three steps. First, the security certificates authenticate 4G modem and Router during IKE. Next, a common IPsec security association (security algorithms and policies) is established between them. Finally, ESP provides integrity, confidentiality and authentication for the GOOSE communication over the Internet.

After establishing a secure IPsec communication path, L2TPv3 tunnel is created and GOOSE blocking messages are exchanged through the L2TPv3 tunnel. The structure of the data frames containing GOOSE message is illustrated in [P5].

6.3.4.2 Automation Real-Time Solution

The 4G Internet is used for GOOSE communication in the Logic Selectivity algorithm. The Internet must be capable of transferring GOOSE messages between the IEDs within the Waiting Time of the algorithm. Applying high-speed Internet with low latency and deterministic behavior is proposed as the automation real-time solution for GOOSE-based Logic Selectivity. Current 4G operators do not support applicable Quality of Service (QoS) for end users. Therefore, it is necessary to measure communication path characteristics in practice.

6.3.5 Final Security-Analysis and Final Automation-Analysis

This section contains analysis for security, automation real-time, and PICARD model.

6.3.5.1 Security Analysis

This Section describes how IPsec in Transport mode provides the security requirements that stated in Section 6.3.3.1.

Integrity: ESP in Transport mode [109] provides integrity for the IP packets. GOOSE messages are placed in the IP payload that is signed along with the appended ESP Header and ESP trailer. Additionally, ESP protocol offers source authentication by adding Authentication Trailer to the end of the IP packet. Thus, IPsec peers verify the data origin.

Confidentiality: The encryption algorithm that is specified during IPsec Security Association encrypts the IP payload that includes the GOOSE blocking message.

6.3.5.2 Automation Real-Time Analysis

This Section analyzes how the applied 4G Internet satisfies the automation real-time requirements that was mentioned in Section 6.3.3.2. In order to evaluate feasibility of the 4G Internet for Logic Selectivity, the communication network characteristics should be measured. For this purpose, the communication setup is prepared in order to record the data traffic between 4G modem and the router. The details of the communication setup devices and applications are explained in [P5]. The aim is to analyze the recorded traffic and investigate whether the GOOSE transmission times over the 4G Internet stay well under 100ms. In the analysis, only GOOSE traffic without IPsec is analyzed because of some limitation in the utilized QoS measurement software. However, we expect IPsec causes insignificant delay when compared to 4G-network delay.

Ten recorded measurements are investigated in order to replicate changing network conditions. The recorded files are analyzed to measure the communication parameters such as jitter, packet loss, and delay. The measurements are affected by two generated data traffics: the additional UDP traffic and the background traffic. In the following, Fig 37 and Fig 38 depict QoS measurements with additional UDP traffics of 200 kbps and 10 kbps, respectively.

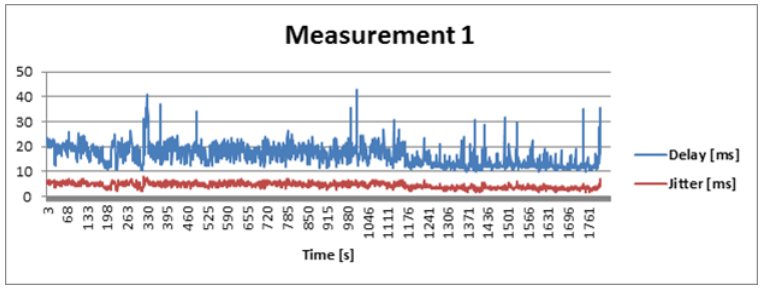


Fig 37. A QoS measurement with 200 kbps additional UDP traffic

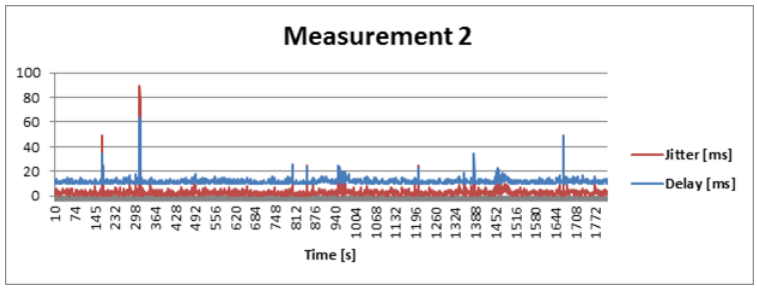


Fig 38. A QoS measurement with 10 kbps additional UDP traffic

In Fig 37, the jitter is around 7ms and the average delay value is below the threshold value of 100ms. In Fig 38, two short connection breaks are encountered, which result in high peak delays at the times 145s and 298s. In these cases, the highest delay value is still smaller than the threshold value i.e. 100ms. However, the jitter peak increase to 90ms that may result the latency to exceed the threshold value (100ms) in some cases such as data encryption.

6.3.5.3 PICARD Analysis

The PICARD requirements for GOOSE-based Logic Selectivity were mentioned in Section 6.3.3.3. Fig 39 shows PICARD analysis in which the security and automation real-time requirements are highlighted (bolded letter) in each step. PICARD analysis only shows two IEDs and one-way communication in order to increase figure clarification. While green elements are trusted links or process, red elements are untrusted ones. The dash lines indicate the trust boundaries. Trust change is not carried out unless IPsec (gradient from red to green) checks for that.

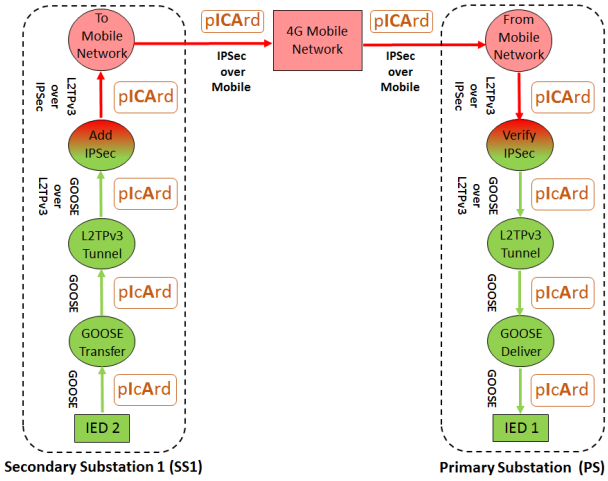


Fig 39. PICARD analysis for the GOOSE-based Logic Selectivity

6.3.6 Effect of Dependable Logic Selectivity on Reliability Indices

Dependable (Secure and Real-Time) Logic Selectively immensely enhances distribution network's reliability. Reliability is the ability of the distribution network to supply uninterrupted power to its clients with the quality demanded by the customers. Reliability can be evaluated by calculating the reliability indices and comparing the effect of alternative reliability improvement methods. In [P5], effect of GOOSE-based Logic Selectivity on the distribution network's reliability is evaluated by calculating SAIDI before and after Logic Selectivity. In the following, both SAIDI and SAIFI are calculated for the lab setup (Fig 32). Since the electrical network is simulated in RTDS, some assumptions should be taken into account: fault rate (λ) of the network is 0.5/100km/year, fault repair time is 3 hours (3h), CB/SW manual operation time is 1h, and CB auto-reclosing time is 30sec (0.008h). Table VI describes the assumptions in the different areas: Area 1 (PS to SS1), Area 2 (SS1 to SS2), Area 3 (SS2 to SS3) and Area 4 (SS3 to PS).

Table VI. The assumptions for the simulated electrical network in RTDS

	Area 1	**Area 2**	**Area 3**	**Area 4**
Length (km)	1 km	2 km	3 km	4 km
Fault Rate (λi)	1*(0.5/100) = 0.005	2*(0.5/100) = 0.01	3*(0.5/100) = 0.015	4*(0.5/100) = 0.02
Customer Number (Nj)	300	200	100	50

$$SAIFI = \frac{\sum_i \sum_j \lambda_{ij} N_j}{\sum_j N_j} \qquad SAIDI = \frac{\sum_i \sum_j \lambda_{ij} R_{ij} N_j}{\sum_j N_j}$$

Rij = outage duration of fault in area i from customers in area j point of view
λij = fault rate in area i affecting to customers in area j
Nj = number of customers in area j

Before Logic Selectivity:

$\sum_i \sum_j \lambda_{ij} N_j$ = [(0.005*300) + (0.005*200) + (0.005*100) + (0.005*50)]+ [(0.01*300) + (0.01*200) + (0.01*100) + (0.01*50)] + [(0.015*300) + (0.015*200) + (0.015*100) + (0.015*50)] + [(0.02*300) + (0.02*200) + (0.02*100) + (0.02*50)] =32.5

Outage calculation in Area 1,2,3,4 when fault is in Area 1 (λ1)

$\sum_i \sum_j \lambda_{ij} R_{ij} N_j$ = [(0.005*3h*300) + (0.005*3h*200) + (0.005*3h*100) + (0.005*3h*50)] + [(0.01*1h*300) + (0.01*3h*200) + (0.01*3h*100) + (0.01*3h*50)] + [(0.015*1h*300) + (0.015***1h***200) + (0.015*3h*100) + (0.015*3h*50)] + [(0.02*1h*300) + (0.02***1h***200) + (0.02***1h***100) + (0.02*3h*50)] =52.5

Outage calculation in Area 1,2,3,4 when fault is in Area 4 (λ4)

$\sum_j N_j$ = 300+200+100+50=650

SAIFI = 32.5/650 =0.05 **SAIDI** = 52.5/650 =0.08 h

After Logic Selectivity:

$\sum_i \sum_j \lambda_{ij} N_j$ = [(0.005*300) + (0.005*200) + (0.005*100) + (0.005*50)] + [**0** + (0.01*200) + (0.01*100) + (0.01*50)] + [**0** + (0.015*200) + (0.015*100) + (0.015*50)] + [**0** + (0.02*200) + (0.02*100) + (0.02*50)] =19

$\sum_i \sum_j \lambda_{ij} R_{ij} N_j$ = [(0.005*3h*300) + (0.005*3h*200) + (0.005*3h*100) + (0.005*3h*50)] + [**0** + (0.01*3h*200) + (0.01*3h*100) + (0.01*3h*50)] + [**0** + (0.015***0.008h***200) + (0.015*3h*100) + (0.015*3h*50)] + [**0** +(0.02***0.008h***200) + (0.02***0.008h** *100) + (0.02*3h*50)] =29.32

$\sum_j N_j$ = 300+200+100+50=650

SAIFI = 19/650 =0.02 **SAIDI** = 29.32/650 =0.04 h

According to the calculations, the GOOSE-based Logic Selectivity immensely improves both reliability indices. While applying circuit breaker (rather than switch disconnector) in the Secondary substation improves SAIFI, the designed algorithm improves SAIDI. However, it has to be noted that reliability indices improvement should be ensured by satisfying security and automation real-time requirements for GOOSE communication.

6.4 Smart Grid Function 4: Customer Automation

Customer automation is regarded as a further extension of DA, which provides the data needed for Demand-side integration, as was explained in Section 2.4. HEMS is used for this purpose by communicating to DER via HAN.

6.4.1 Use-Case: HEMS-BMS Integration in HAN

HEMS is the main automation element making energy management decisions in HAN. In peak hours, HEMS encourages customers to switch their energy consumption from electrical grid to the local energy resources such as battery storage. This requires HEMS communication with battery controller i.e. BMS. This communication is challenging if HEMS and BMS do not support similar communication interfaces and standards. Fig 40 shows an example of the heterogeneous communication parties in HAN.

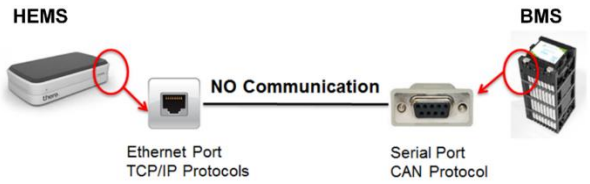


Fig 40. HEMS and BMS with disparate communication interfaces and protocols

In Fig 40, the solution for creating successful HEMS and BMS communication is information integration. In [P1], the use of a protocol converter and Personal Computer (PC) is proposed for HEMS-BMS integration. As can be seen in Fig 41, protocol converter is a USB-to-CAN converter that enables the HEMS to connect with the BMS via a Universal Serial Bus (USB) port in the computer.

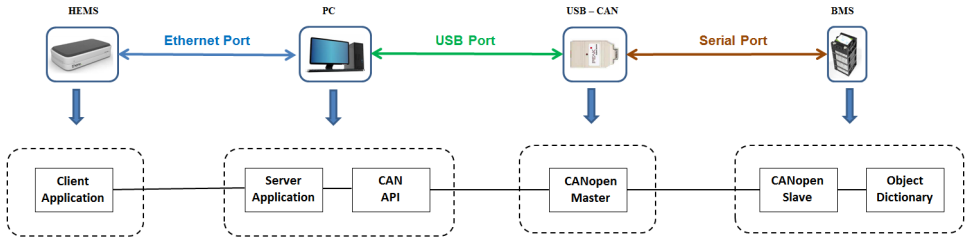


Fig 41. Communication entities in HEMS-BMS integration

In Fig 41, the first integration solution that comes to mind is connecting USB-CAN converter directly to the HEMS. However, a PC is used in the middle for two reasons. First, the USB-CAN device driver has no support for the embedded Linux of HEMS. Second, our study aims to create a secure IP-based communication in the customer automation application. Therefore, an intermediary PC is utilized in order to utilize the possibilities of using IP and security protocols. Network sockets are applied for programming client and server applications located in HEMS and PC, respectively.

USB-CAN device and BMS act as the CANopen Master and Slave, respectively. USB-CAN device includes CAN API that is installed in the PC in order to create the CAN messages required for the server application. The details of the implemented logic and messages are described in [P1]. BMS supports CANopen device profile 401 [113] and has PDO mapping that was mentioned in section 3.1.4. The proposed integration solution makes HEMS capable of communicating with BMS. [P1] includes detailed explanations of the messages for request/response the battery state-of-charge from/to the BMS/HEMS.

6.4.2 Security Vulnerabilities

With reference to Section 2.4.2, various wireless and wired communication protocols are applied in HAN. Therefore, HAN communication encompasses both wireless vulnerabilities and security vulnerabilities. In customer automation, HEMS is the most vulnerable element in the HAN since it is the customer gateway and is the most accessible node for attackers. Undesirable control of energy resources (such as battery) may happen if unauthorized devices are able to impersonate HEMS communication with BMS. Additionally, transmitting raw messages in the HAN increase the risk of traffic analysis

and message modification. This can result in fail operation of HEMS energy management algorithm and consequently unsuccessful Demand-Side Integration.

6.4.3 Security Requirements

Customer automation security requirements can be classified [114] into three categories: customer privacy, customer property security and the customer's feeling of security. Customer privacy emphases anonymization of customer activity data. The second category of security focuses on protecting the customer's resources from unauthorized attackers. The third security category attempts to prevent the customer feeling dissatisfied with the customer automation. The second security category aims to protect end-user resources exchanging data via HAN. In HAN, the order of security requirements is Integrity, Confidentiality and lastly Availability.

6.4.4 Security Solution

In [P1], username/password-based mutual authentication over Secure Socket Layer (SSL) is proposed for creating secured messages for HAN communication.

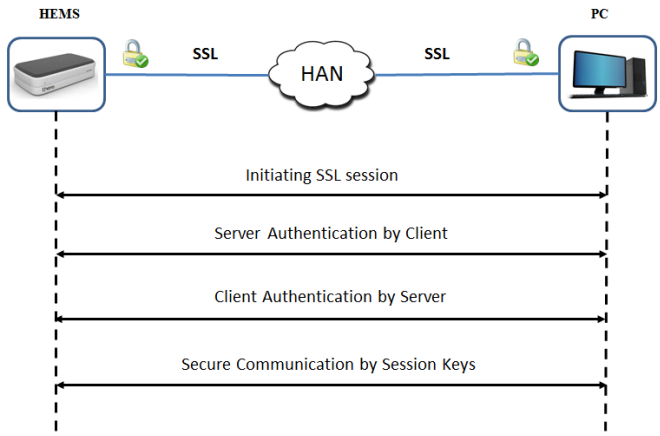


Fig 42. Secured messages for HAN communication

Regarding Fig 42, SSL communication is established between client and server applications that both authenticate each other by exchanging the security certificate and

username/password. The SSL session keys provides integrity and confidentiality for the HEMS communication. The structure of the exchanged data frames are shown in [P1].

6.4.5 Final Security Analysis

This section explains how SSL provides the security requirements mentioned in Section 6.4.3. SSL includes [105] two main groups of protocols: the first group comprises the Handshake protocol, Change Cipher Spec protocol and Alert protocol. The second group contains the SSL record protocol that is used for securing the communication.

Integrity: SSL record protocol uses the security keys generated for the SSL session and creates Message Authentication Code that is added to the application data (CAN messages). Furthermore, mutual authentication allows only authorized HEMS to connect to the PC and thus send CAN messages to BMS.

Confidentiality: The SSL record protocol uses the session keys and encrypts the application data i.e. CAN messages that has the added Message Authentication Code.

6.5 Smart Grid DA Function 5: Smart Metering

Smart Metering obtains benefits from real-time two-way communication and assists for executing ANM and ADA, as was explained in Section 2.5.1. Secondary substations also play a significant role in the smart grid of the future.

6.5.1 Use-Case: Smart Metering Communication in SSAU

The [P3] considers Secondary substation in Smart Metering process and proposes SSAU for transmitting real-time LV data requires in ANM and ADA. This requires the addition of the Smart Metering features to the SSAU. Therefore, SSAU should support both metering and TCP/IP protocols used for NAN and WAN communication, respectively. In NAN communication, SSAU applies DLMS/COSEM protocol to ask the voltage value from smart meter with respect to the OBIS code that was described in Section 3.1.5. The voltage value is stored in SSAU's Database module that was mentioned in Section 2.2.2.

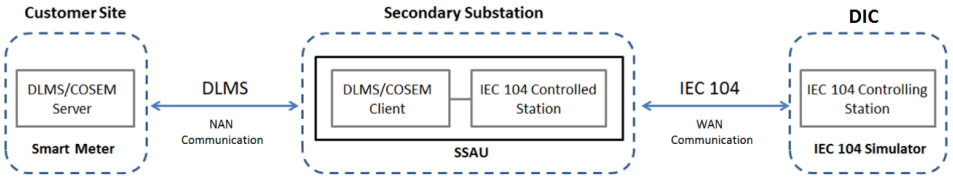


Fig 43. SSAU for real-time transmission of the LV network data

Concerning Fig 43, the SSAU database is configured to internally map the voltage value to the IEC 104 data. SSAU also acts as the IEC 104 Controlled Station that has internal communication with DLMS/COSEM client, and provides real-time metering data to the remote IEC 104 Controlling Station via WAN communication.

6.5.2 Security Vulnerabilities

There are security vulnerabilities in both NAN and WAN communication. Metering data may be manipulated by unauthorized access in NAN or WAN communication. This could result in not only the concealment of customer energy consumption but also the modification of LV network data using for ANM and ADA. Furthermore, customer privacy protection is endangered by transmitting plaintext data in NAN/WAN.

6.5.3 Security Requirements

In Smart Metering NAN/WAN, Integrity is the first requirement to ensure data exchange with legitimate smart meters and SSAUs. Then Confidentiality (and Privacy) is required, and lastly Availability [65].

6.5.4 Security Solutions

While secured messages by DLMS/COSEM security mechanisms are created for NAN, secure communication path by PPTP is established for WAN communication.

6.5.4.1 Security Solution for NAN Communication

Smart meter is DLMS/COSEM server while the SSAU acts as DLMS/COSEM client. The in-built security mechanisms in DLMS/COSEM are employed for securing LV real-time data transmitting between the smart meter and SSAU. DLMS/COSEM security

mechanisms are classified into four main categories: role-based access security, peer authentication, transport security and security logs, all of which are explained in [P3].

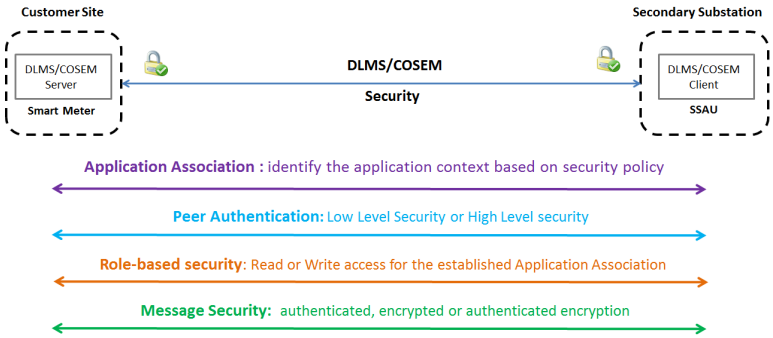


Fig 44. Secured messages for NAN communication in Smart Metering

After successful peer authentication, Application Association is established based on the client type that has defined in the security policy. Peer authentication can be accomplished either by Low Level security or by High Level security, which correspond to unilateral or mutual authentication, respectively. Then, Role-based security provides access control to COSEM data by allowing Read/Write access to the server data, according to the Application Association established by the client. Message security provides encryption and authentication for transporting the messages between smart meter and SSAU. In lab setup, the smart meter configuration software has some limitations for selecting all of the mentioned security mechanisms. In our experiment, Low Level Security with no message security is applied. However, message security must also be applied in practice. The structure of COSEM data secured in DLMS message is shown in [P3].

6.5.4.2 Security Solution for WAN Communication

The IEC 104 standard is used as the communication protocol for WAN communication.

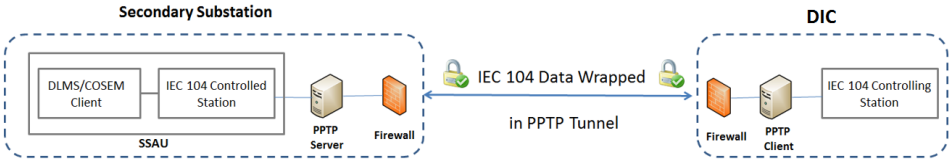


Fig 45. Secure communication path for WAN communication in Smart Metering

IEC 104 messages are transmitted as plaintext without any security assignments, as shown in Fig 13. Therefore, this is not a safe protocol for WAN (Internet) communication. In [P3], PPTP is proposed for securing the communication between SSAU and DIC, as is illustrated in Fig 45. Secure communication path between Secondary substation and DIC is accomplished in two main steps. First, entering username/password for authentication of PPTP client to the PPTP server. As a result, only authenticated DIC is allowed to communicate Secondary substation. Second, confidential transmission of IEC 104 messages (Smart Metering data) in the secure tunnel. PPTP applies Point-to-Point Protocol connections for transporting data and Generic Routing Encapsulation [117] protocol for encapsulating IEC 104 messages in the tunnel. The structure of IEC 104 messages wrapped in PPTP tunnel is illustrated in [P3].

6.5.5 Final Security Analysis

In this section, it is explained that how the proposed solutions satisfy the security requirements stated in Section 6.5.3.

6.5.5.1 Security Analysis in NAN Communication

Integrity: SSAU authentication to the Smart meter by password during Low Level Security mechanism. Furthermore, authentication of DLMS/COSEM message by using [115] the symmetric cryptography suite: Galois Counter Mode with AES-128. This algorithm generates Authentication Tag for the messages that are transmitted between the smart meter and SSAU.

Confidentiality: The Galois Counter Mode with AES-128 is utilized for encrypting the payload of the DLMS/COSEM messages containing the application (COSEM) data.

6.5.5.2 Security Analysis in WAN Communication

Integrity: remote PPTP client is authenticated to the PPTP server by applying Extensible Authentication Protocol (EAP) [116] secured password. This ensures that only the authorized IEC 104 Controlling stations connect to the the SSAU.

Confidentiality: IEC 104 messages (metering data) are incorporated in the payload of the Point-to-Point Protocol, and they are encrypted by Microsoft's Point-to-Point Encryption protocol.

6.6 Discussion

Smart grid decentralized DA architecture not only includes Vertical integration (to the control center) but also Horizontal integration as exemplified in [P3][P4][P5]. These integrations are accomplished via the use of new automation devices and utility Internet that provides real-time connectivity. The utility Internet can even be used for exchanging non-IP protocols, as explained for GOOSE-based Logic Selectivity in [P5]. The Logic Selectivity performance is heavily dependent on the availability of the GOOSE messages and the utility Internet between the substations. These requirements can be met by applying IE switches that support QoS for GOOSE messages and redundancy methods at different levels: IED level (design PRP network in substations), communication network level (using two different mobile network operator for redundant 4G connections), or ISP level (applying redundant Internet channels such as 4G and satellite communication). However, in practice, time-based Selectivity should also be designed as a backup solution to ensure Selectivity in case of communication failure or low service quality.

Utility Internet provides many benefits such as real-time communication for DA messages and even OSI model layer 2 messages. This opens up the possibility of defining new DA application areas which require communication of GOOSE or SV over the WAN. However, the Internet presents security challenges that are dealt with by the proposed cyber-security solutions. These solutions indirectly improve the distribution network's reliability by ensuring that the DA functions operate correctly. The proposed security solutions add security headers to the original messages, which may affect the real-time requirements of the DA application. There are several methods for improving the real-time requirements of the DA applications. In local DA communication (such as substation LAN), highly time-critical traffic (like GOOSE and SV) must be separated from less time-critical traffic (like MMS). This separation can be carried out either physically via the network design (as was done in [P6]) or logically by VLAN technology. Moreover, network traffic prioritization should be applied in which the IE switch must support the QoS feature to prioritize highly time-critical traffic. Furthermore, IEEE 1588v2 PTP must be used for time synchronization in order to ensure on-time delivery of data. In remote DA communication, real-time requirements can be satisfied by utilizing a high performance Internet service (acquired from the ISP) that has acceptable Service Level Agreement parameters such as round trip time and bandwidth availability.

In practical implementations, there are several requirements for utilizing the proposed security solutions for DA data communication. While Primary substations should be upgraded from RTUs to Station Gateways, Secondary substations should be equipped with SSAUs. In addition, Field Communication Gateways (3G/4G router) should be attached to the in-filed RTUs/IEDs. Moreover, the customers should have HEMS located either inside the customer's premises or in the cloud.

The overall security architecture for DA data communication will contain firewalls along with the proposed cyber-security solutions at the communication path level, message level or both. All the private networks among the DA components (Fig 1) should be separated from the utility Internet by firewalls. In local DA communication, TLS/SSL is used for creating secured messages. Therefore, HEMS and Station Gateway must support TLS/SSL in order to provide security for the local networks i.e. HAN and substation LAN.

In remote DA communication, while secure communication path can be established by VPN protocols (IPsec or PPTP); secured messages can be created by OPC UA. The maximum level of security is obtained by transmitting secured messages via OPC UA in the secured communication path by VPN. In practice, IPsec VPN must be utilized and the use of PPTP is not recommended because of the security vulnerabilities [118] in Microsoft's implementation of PPTP. In order to have maximum security for remote DA communication, IPsec and OPC UA must be supported by the communication elements in Fig 19 i.e. Communication Gateways, Station Gateway, Field Communication Gateway, HEMS and SSAU. The SSAU structure (Fig 4) can be complemented by adding a new module, Security Module, in order to incorporate IPsec and OPC UA standards.

In Fig 19, the communication elements can be made OPC UA-compliant either by having built-in OPC UA support, by adding a UA wrapper [106], or being equipped with an embedded [119] OPC UA server at the device level. Although OPC UA was originally developed for industrial automation applications, the use of OPC UA in smart grid DA will also be increased. OPC UA not only provides communication security but also several other benefits such as interoperability, cross-domain communication, direct interaction of IEDs with advanced SCADA software [120], endorsing by the latest database technologies in DIC, and reducing both integration time and cost. Furthermore, OPC UA meets [121] IEC 61850 and IEC CIM standards, which further improves the interoperability [122][123].

7 CONCLUSIONS

This dissertation proposed cyber-security solutions for the smart grid DA functions. The solutions were tested under several example use-cases to demonstrate how the secure communications work. The secure communications were created with real devices and applications in order to provide lab validation of proof of concept.

In substation automation, secure session was established between the TLS client and the IEC61850-TLS proxy server in Station Gateway. The generated session keys secured the messages exchanged in the substation local communication by TLS record protocol. Furthermore, LRE in the designed PRP networks enhanced data availability that is a major concern in a substation LAN. In substation remote communication, the Communication layer of the OPC UA security model created secured messages by signing and encrypting the transmitted data. The OPC UA security model also provided application/device authentication and user authentication mechanisms for the substation remote communication. Securing the local and remote communications ensures reliable SAS operation at the substation and the distribution network levels, respectively.

In feeder automation, ESP in Tunnel mode established a secure communication path for Decentralized feeder automation by signing and encrypting the IEC 104 messages that are located in the payload of the IP packets, and transmitted between CPS and in-field RTU. Securing this communication indirectly improves electrical service availability by ensuring reliable operation of Decentralized feeder automation.

In Logic Selectivity, functional testing of the GOOSE-based Logic Selectivity was carried out in order to experiment standardized (IEC61850) Logic Selectivity and evaluate the algorithm performance under different MV faults. L2TPv3 over ESP in Transport mode established a secure communication path by signing and encrypting the GOOSE blocking messages that are located in the L2TPv3 tunnel secured with ESP. Moreover, the QoS measurements in the GOOSE-recorded traffic indicated that applying 4G Internet with low latency satisfies the automation real-time requirements for the algorithm. In addition, SAIDI and SAIFI calculations showed that GOOSE-based Logic Selectivity greatly reduces both the number and the duration of outages. Establishing dependable (Secure

and Real-Time) communication path for GOOSE messages ensures accurate functioning of the algorithm and consequently improves the distribution network reliability.

In customer automation, integration between HEMS (support TCP/IP) and BMS (support CAN) was accomplished by using a USB-CAN converter and programming the logic that uses CAN API, network socket connection and SSL. The SSL record protocol created secured messages for data exchange in HAN. Furthermore, mutual authentication over SSL ensured only trusted HEMS could communicate in HAN. Securing HAN communication ensures reliable operation of the energy management algorithm in HEMS.

In Smart Metering, DLMS/COSEM security was used to secure NAN communication. Secure communication path for WAN communication was created by PPTP that encrypts the IEC 104 messages wrapped in the PPTP tunnel. Furthermore, EAP provided user authentication that restricts SSAU communication with authenticated DIC. Securing NAN/WAN ensures validity of LV metering data as well as privacy of customers' data.

The proposed security solutions create secured messages, secure communication path or both for five DA functions: substation automation, feeder automation, Logic Selectivity, customer automation and Smart Metering. While the secured messages were created by TLS/SSL and OPC UA security, secure communication paths were established by PPTP and IPsec. In fact, the created messages or the established communication paths satisfy the high-level security requirements (Confidentiality, Integrity and Availability) for the DA data networks that include IP-based industrial ICT standards as well as non-IP protocols such as GOOSE messages. To sum up, DA communication must be dependable (Secure and Real-Time) in order to ensure reliable operation of the DA functions.

Smart grid DA contains new ICT systems as well as those are currently in operation. The proposed solutions are based on the widely accepted IT security protocols supported by most of the current systems as well as newer upcoming ones. This provide benefits such as long-term stability, reduce deployment costs, backward compatibility, and lower the burden of DA security administration. Although, there has to be a trade-off between the applied security protocol and the real-time requirement of the specific application in DA.

The proposed CPS and SSAU applications create Horizontal integration, provide real-time connectivity and distribute DMS intelligence over the substation levels, which are essential for the decentralized DA architecture of the future.

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Publication 1

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Secure Integration of the Home Energy Management System to the Battery Management System in the Customer Domain of the Smart Grid

Peyman Jafary, Sami Repo
Department of Electrical Engineering
Tampere University of Technology
Tampere, Finland
Peyman.Jafary@tut.fi, Sami.Repo@tut.fi

Hannu Koivisto
Department of Automation Science and Engineering
Tampere University of Technology
Tampere, Finland
Hannu.Koivisto@tut.fi

***Abstract*—In the future smart grid, electricity consumption also follows production. Smart grid achieves this aim by applying Demand-Side Integration and integrating of local generation in electricity network operations. This requires Home Energy Management System (HEMS) that controls Distributed Energy Resources (DERs) from one hand and communicates with electrical grid from another hand. In peak hours, HEMS encourages customer to use residential energy resources like battery storage. Therefore, communication between HEMS and battery is required. Information integration is needed if two sides of communication are heterogeneous. The possible solution is locating of a protocol converter in the middle of communication path. This paper discusses about secure integration of HEMS that supports Ethernet to the battery management system that supports Controller Area Network (CAN). Integration is implemented by using of the protocol converter device along with a computer. Client-server model is applied in combination with username/password-based mutual authentication over secure socket layer.**

***Index Terms*—canopen, customer automation, home area network, information integration, secure socket layer.**

I. INTRODUCTION

Smart grid aims to meet the challenges of the next generation of electricity networks. It presents dynamic and intelligent electrical grid by integrating behaviors of the all domains in smart grid [1]. Customer domain is one of the smart grid domains which deals with end-users and interacts with other domains such as distribution, markets, operations, and service provider domains [1] . Smart meter and Home Energy Management System (HEMS) are significant sections of customer domain which enable monitoring of energy consumption and controlling of customer resources respectively. An important term of HEMS is Demand-Side Integration that discusses about the measures to use distributed local generation and energy resources in order to support market and network operations.

HEMS controls resources in home area network and supports both local and remote communication. In local communication, HEMS provides energy management in client premises by running of intelligent local energy management algorithms. Various algorithms [2]-[4] have been proposed that follow multiple purposes such as home appliances efficiency comparison, load prioritization, and selection of proper local energy resources for domestic consumption. Communication between HEMS and local energy source like battery storage system is essential in order to operate the algorithm. This communication is achieved directly if both HEMS and battery storage system support matching communication interface and same communication protocol. However, communication is demanding if they possess disparate communication interfaces and standards.

HEMS that has been used in this experiment supports Ethernet port and Internet protocols. In contrast, Battery Management System (BMS) supports serial interface and Controller Area Network (CAN) protocol. Whereas both parties of communication are heterogeneous with no common communication characteristics, merging of information is necessary in order to create data transmission between parties. The problem is solved by applying of the USB-CAN converter which is utilized between HEMS and BMS. Information integration is performed by two communication steps: HEMS to USB-CAN device, and USB-CAN converter to BMS. Since HEMS supports routing functionality and connects to the Internet, risk of security attacks is increased. Therefore, data transmission between HEMS and USB-CAN are secured by using username/password-based mutual authentication over Secure Socket Layer (SSL).

In the rest of this paper, section II discusses about customer automation in smart grid. Next, secure integration of HEMS to BMS will be elaborated in section III and finally conclusion is provided in the section IV.

II. CUSTOMER AUTOMATION IN SMART GRID

Customer domain of smart grid is divided to different sub-groups such as residential, commercial and industrial customers which support respective automation functions. In residential area, customer automation is considered as the further extension of the distribution automation and provides automatic demand response requirements by creating dynamic behaviors for end-users of electricity. Customer automation presents different functionalities such as integration of electric vehicles, remote reading of meters, controlling of load, and energy management capability. These functionalities are obtained by communication between smart devices in customer premises through home area network [1].

A. Home Area Network Components

Local network in group of smart digital equipment within the customer premises is called Home Area Network (HAN). Smart devices use this network to interact with each other and other resources in order to facilitate home automation requirements. The most common devices in HAN are: controllable thermostats (heating and cooling loads), smart home appliances, local energy resources, PCs and smartphone, HEMS, and electric vehicle charging station. HEMS is central control unit that administers automation decisions in HAN. As can be seen in the Fig.1, HEMS also communicates with smart meter. This communication interconnects distributed energy resources to smart meter and presents abilities such as Demand-Side management and active distribution network management [6]. In addition, HEMS acts as a communication interface for data transmission to the next hierarchy information level which is aggregator software tool that locates between customer and electricity market. Aggregator is the centralized information integration that collects data of small-scale resources from multiple customers [7].

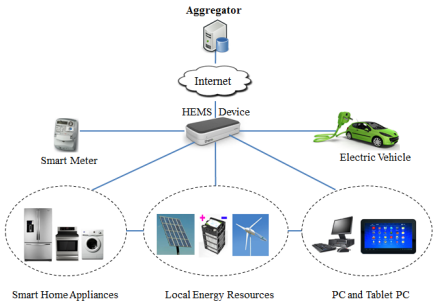

Figure 1. Home area network components

Both wired and wireless technologies are used in HAN. While CAN, Ethernet, and HomePlug [8] are examples of wired technologies; wireless technologies include wireless LAN, Zigbee [9] and Z-wave [10].

B. Information Integration in Home Area Network

Energy demand management algorithms are implemented by HEMS in order to intelligently switch customer consumption from electrical grid to local energy sources. Communication between HEMS and local energy resources is indispensable in order to check the availability of existing energy resources in customer premises. Fig.2 depicts an example of communication between HEMS and BMS.

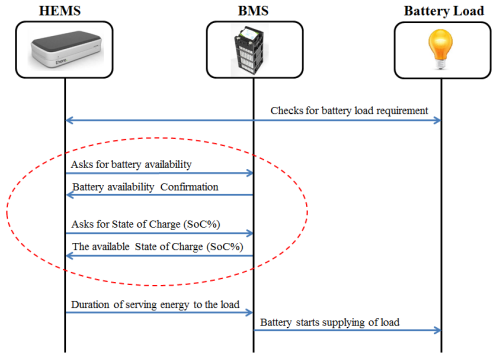

Figure 2. Partial interaction diagram between HEMS and BMS

In the above figure, HEMS checks battery load requirement and then asks for the battery availability. Next, HEMS asks for the State of Charge (SoC%) in the battery and decides about duration of time that load can be supplied from the battery. Finally, battery starts supplying of the load. It is supposed that battery is available and has enough charge to cover the load energy requirement. Participants in HAN are equipped with different networking interfaces which are based on their operation, cost and processing power. As it was highlighted in the Fig.2, HEMS and BMS need to communicate and information integration is required if they include different communication interfaces.

C. Security in Home Area Network

State-of-the-art data network infrastructures in smart grid propose interaction between customer domain and external information systems. This communication provides advantages such as remote meter reading and Demand-Side Integration but on the other hand it presents security issues like customer privacy limitation or unauthorized use of customer properties [11]. The security issues in customer domain can be divided to three categories: customer privacy, customer property security and feel of security by customer [12] .While the first category focuses on securing of customer activity information, the second class of security concentrates on protecting of customer resources and devices from unauthorized attacker. The last group of security discusses about preventing from dissatisfaction feeling of customer about smart grid systems. Displeasure impression of end-user can lead to unsuccessful implementation of the smart grid.

From security point of view, HEMS is the most vulnerable element in HAN since it is the most accessible node by attackers. Moreover, connecting HEMS to the Internet enhances its vulnerability. As HEMS utilizes both wireless and wired technologies for data communication, consequently

home area network can be subjected to either wireless attacks or computer networking attacks. Traffic analysis and jamming attacks are examples of wireless attacks. Computer networking attacks include Eavesdropping, unauthorized access to customer devices, Man-in-the-middle attack, and Denial-of-service attack.

III. SECURE INTEGRATION OF HEMS TO BMS

As it was explained in the previous section, information integration is desired to complete data transmission between HEMS and BMS that contain different communication interfaces. HEMS device in our research work is ThereGate by There Corporation. It is a programmable controller that includes CPU, WLAN router, Ethernet switch, GSM/GPRS/3G, and integrated home automation functionalities. ThereGate runs on an embedded Linux operating system and supports TCP/IP and Ethernet ports for both LAN and WAN networks. The BMS device, developed by European Batteries Corporation, manages battery operation and supports CANopen generic I/O profile 401 standard [5] and serial communication interface. CANopen is higher layer protocol for Controller Area Network (CAN) devices. The BMS is CANopen slave device which can be controlled by external CANopen master.

A. Information Integration Requirements

There are several alternatives for integration of the HEMS to BMS. CAN-Ethernet Bridge or CAN-TCP/IP Gateway is an example of devices which can be used for integration. These devices make information integration possible but they have limited support for communication security standards. Since this experiment investigates secure data communication between HEMS and BMS, it brings the idea of using a Personal Computer (PC) that gives us freedom to think about various security protocols such as SSL. HEMS device (ThereGate) also supports SSL and can connect to the Internet with different configuration.

Integration is carried out by using of the PC and USB-CAN converter that model Ethernet-CAN adapter. PCAN-USB device, produced by PEAK-System, acts as USB-CAN converter and enables connection of the HEMS device to the CAN network of BMS via a Universal Serial Bus (USB) port in the PC. The connection from HEMS to PC can be completed either wirelessly through WLAN or via Ethernet cable. Ethernet cable is selected in our experiment.

Figure 3. Information integration between HEMS and BMS

According to the Fig.2 in the previous section, ThereGate needs to ask BMS about the State of Charge (SoC%) of the battery. Fig.3 shows an integration solution that makes this communication possible.

BMS supports CANopen device profile 401 [5] and the implemented Process Data Objects (PDOs) to be transmitted/received are specified by PDO mapping in the Object Dictionary of the BMS. PDOs are applied for real-time transmission of battery data and have their own mapping parameter list. PDOs can be transmitted either by occurrence of an event (event-driven transmission) or by reception of CAN request messages such as SYNC message or Remote message. Remote message is chosen in our testing.

In regards to the BMS data sheet, the value of the State of Charge (SoC%) exists in the second Transmit Process Data Object (TPDO2) in the Object Dictionary of the BMS. The SoC data are sent to the caller (ThereGate) upon the correct remote message receives by the BMS. The communication object identifier (COB-ID) for remote message is calculated in the hexadecimal format: COB-ID = 0x280 + Node-ID.

The Node-ID is the address that is assigned to the BMS which is CANopen slave device. The node address "20" (hexadecimal equivalent is 0x14) is configured to the BMS by using terminal software tool via its serial interface. Consequently, the COB-ID of the remote message is equal to 0x294 (0x280+0x14). This is the message identifier section that should be incorporated in the CAN remote frame along with other required fields for the remote frame. BMS sends the SoC% to the ThereGate when the CAN remote frame contains the mentioned COB-ID receives by the BMS. This CAN remote message should send to the BMS by the CANopen master that is PCAN-USB device. PCAN-USB device supplies with CAN Application Programming Interface (API), PCAN-Basic API, which provides API functions for easy development of software with CAN support. One of the API functions in the PCAN-Basic API is sending remote message by identifying the COB-ID for the remote message, other parts of the CAN remote frame is calculated by the API.

Network socket programming and PCAN-Basic API are software solutions in order to complete the communication between HEMS (ThereGate) and BMS. Client application in ThereGate uses network socket to send the COB-ID of the CAN remote frame to the server application in the PC. The server application in PC uses PCAN-Basic API libraries and creates respective CAN remote frame and delivers that to the USB side of the PCAN-USB device through the USB port of the PC. Finally, PCAN-USB converts the received remote frame which is in USB data format to the CAN data format and sends that to the BMS via its serial side. The response to this CAN remote message is a CAN data frame contains the value for SoC% of the battery. This CAN data frame sends back from BMS to the ThereGate by travelling from the intermediate devices.

B. Securing Data Communication in the Integration Model

The integrity of data between HEMS and BMS is vital since incorrect data have impact not only to the customer energy management but also to the high level decision of the aggregator [7] for implementing Demand-Side Integration.

If the attacker is able to penetrate inside the HEMS, he finds access to the sensitive information which is transmitted between HEMS and BMS. Then, the attacker is capable of putting battery in nonfunctional state by sending unrelated CAN messages. If the attacker can make the battery of one customer inactive, the risk also exists for other customers and this may affects to the aggregator decision.

Encryption and authentication are applied in order to secure data communication against passive and active attacks such as eavesdropping (especially when HEMS and PC communicates wirelessly) and message alteration respectively. The applied security protocols provide customer property security [12] which is battery in this experiment. The software and hardware characteristics of the implemented model in our testing are depicted in the Fig.4.

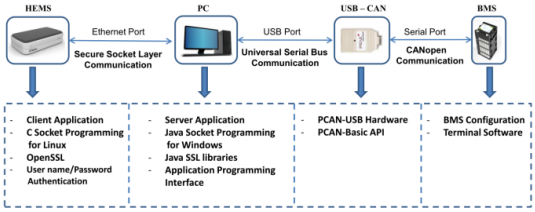

Figure 4. Software and hardware charactristicts of the integration solution

The username/password-based mutual authentication over SSL is applied in order to enhance the security of communication between client and server applications. SSL converts raw messages (COB-ID in our testing) to the unclear ciphertext and mutual authentication guarantees that just authorized HEMS can connect to the server application. In mutual authentication both client and server authenticate each other by the following steps:

- Client application in HEMS requests access to the protected server application in PC.
- Server presents its SSL certificate to the client.
- Client verifies the certificate of the server and if it is trusted certificate, server is authenticated by the client.
- Client sends its username/password to the server.
- Server verifies the client's credentials and if verification is successful, client is also authenticated by the server.
- Client application in HEMS is granted access to the server application.

After successful mutual authentication, the calculated COB-ID (0x294) for CAN remote message sends from HEMS to the PC in encrypted format. Server receives the COB-ID and creates the related CAN remote message by the aid of programming libraries in the PCAN-Basic API. The CAN remote message conveys to the USB-CAN converter in the USB data format. Then, USB-CAN converter converts the USB data packet to the CAN remote frame and sends that to the BMS with CAN communication protocol. The response to this message is SoC% which exists in the TPDO2 and sends back to the HEMS.

In the tested model, server application fulfills the majority of the tasks. The implemented logic in server application is depicted in the Fig.5. Server application developed in Java secure socket programming for the Windows operating system in the PC.

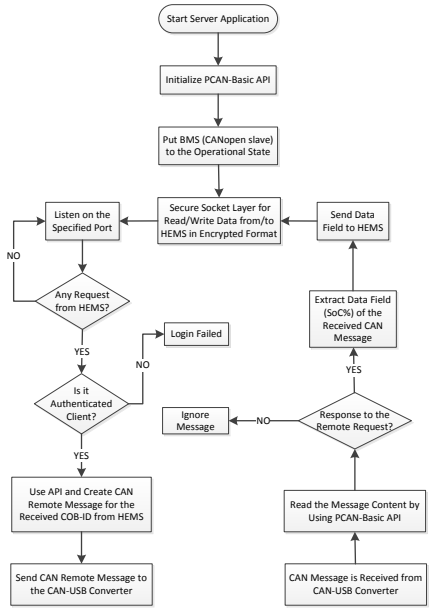

Figure 5. The implemented logic in the server application

Server receives the CAN response message to the calculated CAN remote message via USB-CAN converter. Then, server application extracts the data field of the received message and sends that to the HEMS with secure socket layer protocol. The data field of the received CAN message contains eight bytes of data and its value is "0x5B00000000000000". According to mapping parameters list in the object dictionary of the BMS CANopen slave, the SoC% of the battery is mapped to the first byte of the data field i.e. SoC% = 0x5B = 91%.

The client application in HEMS receives the data field of the received CAN frame and interprets the first byte of data field (SoC =91%) in order to make decision about the duration of time that loads can be supplied by the battery.

The SSL protocol provides confidentiality and integrity for the network socket connection. First, it applies Message Authentication Code (MAC) to the application data. Next, the obtained message is encrypted. Finally, SSL record header is added to the generated message and transmitted in a TCP segment [13].

In addition, further level of security is obtained for the system by applying physical security which is a segment of Defense-in-Depth security model [14]. Physical security

restricts physical access to HEMS and USB-CAN converter by locating HEMS and USB-CAN converter in the safe place with locking in order to avoid physical connection failure.

Table below illustrates Ethernet and CAN frames that are transmitted between HEMS and BMS in our testing.

TABLE I. TRANSMITTED ETHERNET AND CAN FRAMES IN THE INTEGRATION SOLUTION

No	Communication Path	Message Content Explanations	Data Frame Structure
1	HEMS to PC	Application Data: 0x294 in Encrypted Format	Preamble | Ethernet Header | IP Header | TCP Header | SSL Record Header | Encrypted Application Data | CRC Field
2	USB-CAN to BMS	CAN Remote Frame, ID = 0x294, RTR = 1 No Data Field	Start Of Frame | 11-bit ID | RTR | Control Field | CRC Field | Acknowledge Field | End of Frame Field
3	BMS to USB-CAN	CAN Data Frame, ID = 0x294, RTR = 0 data=0x5B000000000000	Start Of Frame | 11-bit ID | RTR | Control Field | Data Field | CRC Field | Acknowledge Field | End of Frame Field
4	PC to HEMS	Application Data: 0x5B000000000000 in Encrypted Format	Preamble | Ethernet Header | IP Header | TCP Header | SSL Record Header | Encrypted Application Data | CRC Field

IV. CONCLUSION

This paper presented secure information integration between home energy management system and battery management system. From device point of view, USB-CAN converter along with personal computer was used to perform integration. Software models included client-server model along with application programming interface for Controller Area Network protocol. Data communications were secured by applying secure socket layer protocol with username/password-based mutual authentication over secure socket layer.

Protecting of communication in home area network is recommended since customer domain is connected to the Internet and it is exposed to the information security threats. By applying the proposed secure integration solution, home energy management system and battery management system securely communicates to each other in order to accomplish customer energy management algorithms efficiently. Furthermore, this protection creates validity for the required data of Demand-Side Integration which are transmitted from customer domain to other domains of smart grid.

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Publication 2

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OPC UA Security for Protecting Substation and Control Center Data Communication in the Distribution Domain of the Smart Grid

Peyman Jafary, Sami Repo
Department of Electrical Engineering
Tampere University of Technology
Tampere, Finland
Peyman.Jafary@tut.fi, Sami.Repo@tut.fi

Mikko Salmenpera, Hannu Koivisto
Department of Automation Science and Engineering
Tampere University of Technology
Tampere, Finland
Mikko.Salmenpera@tut.fi, Hannu.Koivisto@tut.fi

Abstract— **The distribution domain of the smart grid incorporates advantages of the newest substation automation standards in order to enhance distribution network automation. State-of-the-art distribution automation solutions use the public Internet for exchanging data between substation and control center. This presents challenges for cybersecurity, particularly for critical data determining distribution network operation. Therefore, Internet communication between substation and control center should be carried out via a secure communication protocol. OPC Unified Architecture (UA) is an interoperable communication standard supports Internet protocols from one hand and obtains benefits from mature built-in security mechanisms from other hand. This paper describes a solution for secure data transmission between modern substation and control center over the Internet. In this approach, circuit breaker position data is chosen as the data example that is defined in respect to the IEC 61850 data model and securely transmitted to OPC UA client application at remote control center by employing the OPC UA security architecture functions.**

Keywords—distribution automation; IEC 61850; OPC UA security model; smart grid; substation automation

I. INTRODUCTION

One of the major challenges in industrial control systems and SCADA has been providing standard access to the automation data from devices of various manufacturers with different communication interfaces. The primary effort for solving this challenge was presenting OLE for Process Control (OPC) which is the standardized interface based on the Microsoft COM/DCOM technologies for exchanging real-time data in the client-server model [1]. The most recent OPC specification is OPC UA (OPen Connectivity Unified Architecture) [2] which was presented to overcome the limitations of classic OPC specifications, and provides a common object-oriented model for all OPC data in the secure way. Security is enhanced in the OPC UA specification (IEC 62541) by defining OPC UA security model that addresses security requirements [3].

In the distribution domain of the smart grid, high degree of distribution automation is enabled by integration of automation applications at control center, modern substation automation systems and geographically dispersed devices [4]. Control center SCADA has data connections with applications inside and outside of the control center. Future SCADA software uses the IEC 61968 and IEC 61970 standards for communication with internal applications such as Distribution Management Systems (DMS) and Energy Management Systems (EMS). Additionally, SCADA remotely communicates with substations via the use of widespread communication protocols such as the IEC 60870-5-101/104, DNP3, and OPC UA.

OPC UA protocol runs over TCP/IP protocols, and provides secure cross-domain communication between OPC UA client and server over the Internet. These features make OPC UA a suitable candidate for communication in the smart grid and distribution network automation [5]. State-of-the-art substation automation systems support the IEC 61850 standard operating over the regular IT networking protocols. Consequently, connectivity between substation data network and control center network can be accomplished via standard IP-based networks. The latest distribution automation solutions use the Internet for data communication between substation LAN and control center network.

Internet provides flexible and cost effective communication solution for the smart grid. However, risks caused by network security threats are also increased. Therefore, securing exchanged data between substation and control center is mandatory. While using of Internet security protocols have been proposed [6] for data protection, applying application layer security protocols are also recommended to increase security of critical data transmission.

This study applies the OPC UA security methods in order to sign, encrypt and authenticate messages between modern substation communication gateway and OPC UA client at control center via the Internet. These messages encompass diverse information including the substation circuit breaker position data. In this experiment, the position data is used as a transmitted data example. The substation communication gateway has OPC DA server for IEC 61850, and receives position of Medium Voltage (MV) switch from protection relay referring to the IEC 61850 data model. Feeder protection relay

maps the IEC 61850 data to the Manufacturing Message Specification (MMS) protocol [7], and forward it to the communication gateway through the substation LAN. The aim is to study secure Internet connection between the substation gateway OPC DA server and remote OPC UA client. This is achieved by using the OPC UA wrapper application [2] that is OPC DA client from one side and OPC UA server from other side. The OPC DA client side is connected to the gateway OPC DA server and the OPC UA server side provides secure data connection for remote OPC UA client at control center.

The rest of this paper is structured as follows: substation automation in the distribution domain of the smart grid is explained in the section II. The section III discusses data protection in substation and control center communication. Next, section IV describes use case: secure transmission of circuit breaker position data from substation to control center. Finally, security analysis of the use case and conclusion are presented in the section V and section VI respectively.

II. SUBSTATION AUTOMATION IN THE DISTRIBUTION DOMAIN OF THE SMART GRID

The smart grid benefits from advanced automation technologies utilized to improve electrical network productivity and performance. Modern substation automation systems enhance substation operation efficiency and increase the automation level in the entire distribution network.

A. Automation in Legacy and Modern Substations

Legacy substation automation systems are vendor dependent with basic level of automation that is achieved through the use of traditional measurement devices and Fieldbus networks. As can be seen in the Fig. 1, relay in each feeder receives respective measurements from Current and Voltage Transformer (CT and VT) as the Analogue Signal via Hard Wiring (ASHW). Feeder relays exchange data via Fieldbus Hard Wiring (FBHW) that links relays together, and ends to the higher level Fieldbus interface within the substation [8]. The Fieldbus protocol depends on the relay manufacturer.

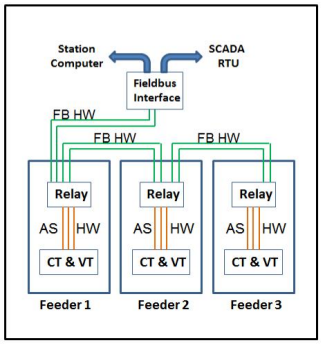

Fig. 1. Legacy substation automation systems

The Fieldbus interface presents feeders' data to the station computer for local use and SCADA Remote Terminal Unit (RTU) for remote usage. The RTU is connected to the industrial modem that transmits data to remote control center via dial-up connection or radio link.

In modern substation automation, a single Ethernet-based data network (substation LAN) is used for data exchange among measurement, protection and control devices within the substation. The latest generation of substation protection and control devices are called Intelligent Electronic Devices (IEDs). They are programmable equipment supporting some level of intelligence along with advanced ICT protocols. In addition, State-of-the-art substation automation systems support the IEC 61850 standard. It is applied as a global communication model for substation automation systems regardless of the device/application manufacturer. Fig. 2 depicts the data network infrastructure in a modern substation.

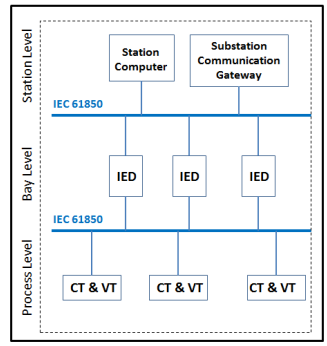

Fig. 2. Modern substation automation structure

The IEC 61850 standard includes information models that describe substation automation devices and their functions in a hierarchical structure. In the IEC 61850 data structure [9], a substation automation device with its functions is hierarchically modelled as: Physical Device (PD), Logical Device (LD), Logical Node (LN), Data Object (DO) and Data Attribute (DA). The IEC 61850 modelled data are mapped to protocols such as GOOSE [7], Sampled Values (SV) [10] and MMS [7] in order to transmit both real-time and non-real-time data within the substation data network. Different levels are defined in the modern substation by respect to the location of devices and data communication.

B. Data Communication in Modern Substations

As shown in the Fig.2, three levels are defined in the modern substation network: Process level, Bay level, and Station level. The Process level includes modern measurement devices that publish measurement data to the process bus as the digital signals that are called Sampled Values. The Bay level contains IEDs that exchange data within the bay level, and also with control and automation devices at the Station level.

Communication between all the mentioned levels is carried out via the Ethernet-based network in accordance to the IEC 61850 standards. Communication in modern substation data network is classified into two categories: horizontal and vertical communication. The horizontal communication

address data exchange between IEDs in the bay level and the vertical communication is related to data transmission between the bay level and the station level devices.

In the modern substations, a communication gateway is used for data transmission between substation data network and control center. The communication gateway is a multi-functional device with more capabilities than a typical RTU. The gateway supports advanced electrical protection functions and substation automation standards including IEC 61850. It is also able to use Internet-based communication for data transmission between a modern substation and control center.

III. DATA PROTECTION IN SUBSTATION AND CONTROL CENTER COMMUNICATION

As it was mentioned, a modern substation applies the Internet as communication channel for data exchange between substation and control center. The Internet presents many advantages such as scalability, alternative transmission options, and worldwide remote access. However, transmitted data must be protected against cybersecurity threats as the Internet is a public network, and raw data can be accessed or modified by unauthorized attackers.

A. Communication Security Requirement

Communication between substation and control center contains diverse information such as measurement data, status of switches, control commands, acknowledgements, substation alarms and events. Some of these data are considered as critical information that directly affects to the operation of the substation critical devices and interlocking systems. If critical data are not protected, various security attacks such as the man-in-the-middle attack may happen in which the attacker is able to modify critical data. This is lead to physical harm to substation devices or undesirable function of control applications in control center. Therefore, critical data must be guarded against security threats in the public network. In other words, confidentiality, integrity and availability of the critical data must be assured.

Multiple competitive communication standards such as Modbus/TCP, IEC 60870-5-104, DNP3, and OPC UA can be used for Internet connection between substation and control center [11] [12]. OPC UA is considered as the preferable protocol candidate for exchanging data between substation and control center because it contains comprehensive inbuilt security functions that have been defined in OPC UA protocol specification [13]. Moreover, OPC UA can be applied along with the IEC 61850 standard. It provides a secure communication foundation between distributed applications of the smart grid [5].

B. OPC UA Security Model

OPC UA security model manages security functions in different layers: application layer, communication layer and transport layer. These security layers [13] cover essential data security objectives such as integrity, confidentiality, availability, authorization and authentication. OPC UA itself is the OSI model application layer protocol and the mentioned security layers should be differentiated from the OSI model layers. The OPC UA security model is shown in the Fig. 3.

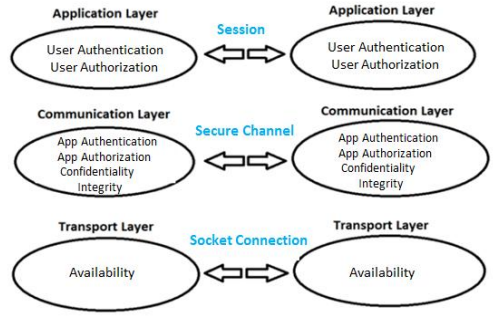

Fig. 3. OPC UA security model

As can be seen in the Fig. 3, the application layer provides user's authentication and authorization via a logical connection between UA server and UA client that is called session. User authentication can be done by exchanging username/password, X.509 certificates or WS-Security token. The authorization for the authenticated user depends on the implementation of the UA server by each manufacturer.

The communication layer of the OPC UA security model offers confidentiality, integrity and application authentication. Real-time data are exchanged between client and server in a session in which data transmission are secured by establishing a secure channel. The communication layer applies encryption for confidentiality, digital signature for integrity and certain type of X.509v3 security certificate for application authentication [13].

System accessibility is enhanced by transmitting of secured data through the socket connection that applies error recovery techniques in the transport layer of the OPC UA security model.

IV. USE CASE: SECURE TRANSMISSION OF CIRCUIT BREAKER POSITION DATA FROM SUBSTATION TO CONTROL CENTER

Control center contains different applications such as SCADA, DMS, UA clients and servers. These applications receive data from substations in order to make decisions and send back commands to substations for network management in both normal and fault conditions. Integrity and accuracy of the transmitted data is necessary to maintain correct network operation.

In this experiment, the MV circuit breaker position data (open/close) is securely sent from substation to control center by applying IEC 61850-compliant devices and OPC UA protocol for Internet communication.

As can be seen in the Fig. 4, a single MV feeder is simulated in the Real Time Digital Simulator (RTDS)

hardware. The simulated MV feeder is externally controlled by a feeder protection IED that has data connection with the substation communication gateway. Both feeder IED and gateway are IEC 61850-compliant devices from ABB products: ABB REF615 [14] and ABB COM600 [15] respectively.

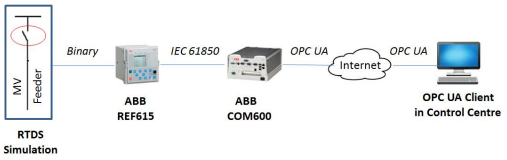

Fig. 4. Project device arrangement

RTDS includes a digital output that models the feeder circuit breaker position (open/close) as the binary signal (on/off) that is sent to the digital input terminal of the feeder IED. This binary signal should be defined for the feeder IED in the IEC 61850 format (IEC 61850 dataset). This dataset is transmitted to the communication gateway that sends the dataset to the OPC UA client application [16] via the Internet. This UA client can be considered as the OPC UA module of control center SCADA software. The aims are: first to define the circuit breaker position as the IEC 61850 dataset for communication within substation data network. Next, apply OPC UA and its security model to securely send the dataset to the external UA client via the Internet.

A. Circuit Breaker Position Data in the IEC 61850 Format

The IEC 61850 dataset for the circuit breaker position is defined by respect to the IEC 61850 hierarchy data model (PD.LD.LN.DO.DA) that was mentioned in the section II. The feeder IED includes the IEC 61850 configuration software tool for defining the dataset that is described in the table I.

TABLE I. DEFINE CIRCUIT BREAKER POSITION DATA IN THE IEC 61850

NO	IEC 61850 Data Naming	Description
1	PD	The feeder IED hardware device (REF615)
2	LD	The IED includes multiple logical device functions such as protection, monitoring and control. The control function (CTRL) is selected.
3	LN	Every LD contains respective logical nodes. The logical device CTRL consists of several logical nodes. The logical node related to circuit breaker (CBXCBR1) is chosen.
4	DO	Specific data objects are defined for the circuit breaker logical node. The position data object (pos) is elected.
5	DA	There are various data attributes for the position data object. The Boolean (on/off) data attribute (stVal) is selected as the DA. This Boolean attribute corresponds to the position data binary signal (open/close) that is entered to the feeder IED from RTDS.

The feeder IED configuration software (PCM600) [17] has IEC 61850 configuration tool. The IEC 61850 dataset (PD.LD.LN.DO.DA) for the circuit breaker position data is specified as the:

REF615.CTRL.CBXCBR1.pos.stVal

The PCM600 can be used for managing the feeder IED data communication in all the levels of the IEC 61850-compliant substation: Process level (measured Sampled Values to IED), Bay level (GOOSE messages communication between IEDs), and Station level (MMS communication between IED and the substation communication gateway).

In this experiment, the RTDS is considered as a device in the process level of a modern substation. The feeder IED and the substation communication gateway are located in the bay level and the station level respectively.

The feeder IED is configured to perform the vertical communication (from bay level to station level) that maps the defined dataset to the Manufacturing Message Specification (MMS) protocol, and transmits the dataset to the substation communication gateway. The substation gateway undertakes to transmit the received IEC 61850 dataset to the OPC UA client at control center.

B. Secure Transmission of the Dataset with OPC UA

As it was depicted in the Fig. 4, the goal is to transmit data between the substation communication gateway and control center by applying OPC UA standard via the Internet. The substation gateway includes configuration software (SAB600) that is utilized for IEC 61850 data communication and engineering to/from the substation gateway. First, MMS communication for the defined IEC 61850 dataset from the feeder IED to the substation gateway is configured in the SAB600. Next, the SAB600 is configured to apply the OPC standard for transmitting the defined 61850 dataset to the OPC UA client application at control center network.

The substation communication gateway supports IEC 61850 OPC Data Access (DA) server in which the circuit breaker position data is presented as an OPC item that is accessible for remote OPC DA clients. The main challenge here is to create connection between two incompatible communication protocol entities i.e. the substation gateway IEC 61850 OPC DA server and the control center OPC UA client.

The solution for enabling OPC UA client to connect the gateway IEC 61850 OPC DA server is using the OPC UA wrapper application [2]. The UA wrapper functions as both OPC DA client and OPC UA server that are connected to the substation gateway and control center client application respectively. The OPC UA client application from OPC Foundation [16] and the wrapper application developed by Unified Automation [18] are utilized in this experiment. Figure below displays the data communication steps from RTDS in the substation data network to the OPC UA client application in control center.

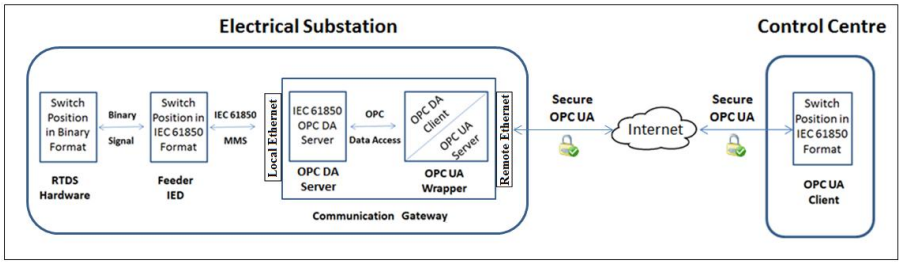

Fig. 5. Data communication steps from substation to control center

The OPC UA wrapper application runs on Microsoft Windows operating system. There are two possibilities for installing the UA wrapper application. It can be installed either on the substation communication gateway or in the external computer within the substation. In this case, the UA wrapper application is installed on the communication gateway because of compatibility and security reasons. The UA wrapper application is compatible with the substation gateway operating system that is embedded Microsoft Windows. In addition, the security is also enhanced because installing the wrapper application in the external computer requires the configuration of the external access to COM object (DCOM) over the network increasing potential attack surface on the gateway.

The substation gateway has two Ethernet ports: local and remote. It is connected to the feeder IED and other devices in the substation LAN through the local Ethernet port. Furthermore, the gateway is connected to the Internet via the remote Ethernet port. The installed wrapper application in the gateway presents the OPC UA communication between the gateway and the OPC UA client at control center. There are two types of data encoding are specified in OPC UA specifications: OPC UA native binary and XML. OPC UA binary protocol is selected for this experiment with UA TCP as the transport protocol.

In this way, OPC UA client is able to read the circuit breaker position data in the IEC 61850 data format. The OPC UA security protocols perform data protection functionalities that are described in the next section.

V. SECURITY ANALYSIS OF THE USE CASE

The OPC UA security model creates secure data communication between the OPC UA client and the wrapper. First, data availability is confirmed by creating socket connection. Second, security mode and security policy are applied for creating secure channel. The security mode is selected as the SignAndEncrypt in which transmitted messages are both signed and encrypted. The security policy is selected as the Basic128Rsa15 [19] in which security algorithms apply RSA15 for Key-Wrap-algorithm and 128-bit encryption. When the secure channel is established, the UA client and the UA wrapper applications are authenticated by exchanging certain X.509v3 certificates which are called Application Instance Certificates (AICs). Secure channel that is basically utilized for deriving the symmetric keys which are applied for signing and encrypting of the subsequent messages.

Finally during the session establishment, UA client and wrapper exchange their Software Certificates (SCs) that identify the products and supported profiles [13]. In this experiment, user authentication is also performed during session establishment. The identity of the control center person that intends to connect the UA wrapper is proved by presenting user credential (username/password) to the wrapper. Fig. 6 depicts the data flow in secure connection establishment between UA client and UA wrapper.

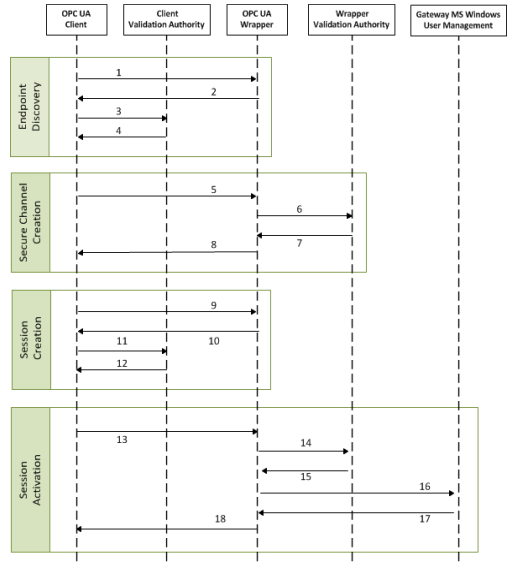

Fig. 6. Secure connection establishment between UA client and UA wrapper

Secure connection establishment between the UA client and UA wrapper is accomplished in four stages: endpoint discovery, secure channel creation, session creation and session activation [13]. Each stage includes specific OPC UA messages and security credentials which are described in the table II regarding to the Fig. 6.

TABLE II.MESSAGE DESCRIPTION IN SECURE CONNECTION ESTABLISHMENT BETWEEN UA CLIENT AND UA WRAPPER

OPC UA Security Model		Stage	Message Number	Message Description	Security Credentials
Transport Layer	Communication Layer	Endpoint Discovery	1	UA client sends GetEndpoints Request to the wrapper in order to realize different UA server configuration.	Wrapper's AIC
			2	Wrapper sends GetEndpoints Response that includes the wrapper's AIC.	
			3	Client asks from its validation authority in order to validate the received wrapper's AIC.	
			4	The client validation authority responses that the received wrapper's AIC is a trustworthy certificate.	
		Secure Channel Creation	5	Client sends the OpenSecureChannel Request that includes the client's AIC. This message is sent by respect to the chosen security policy and mode: the security policy is Basic128Rsa15 and the security mode is Sign and Encrypt. This security mode assures both integrity and confidentiality of the transmitted message by signing the message with private key of the client's AIC, and encrypting the message with public key of the wrapper's AIC.	Wrapper's AIC, Client's AIC
			6	Wrapper asks from its validation authority about the validity of the received client's AIC.	
			7	The wrapper validation authority is confirmed that the received client's AIC is truthful.	
			8	The wrapper sends the OpenSecureChannel Response message which is secured with same security policy and mode i.e. signs the message with private key of the wrapper's AIC, and encrypts the message with public key of the client's AIC.	
	Application Layer	Session Creation	9	Client sends CreateSession Request to the wrapper. This message is secured with the chosen security policy (Basic128Rsa15) and mode (Sign and Encrypt) but the derived keys during secure channel establishment are used for signing and encrypting the message.	Derived Keys, Wrapper's SC
			10	Wrapper replies by the CreateSession Response message. This message contains the wrappers' SC.	
			11	Client asks its validation authority to validate the received wrappers' SC.	
			12	The validation result is sent back to the client. The wrappers' SC is considered as trustworthy certificate.	
		Session Activation	13	The ActivateSession Request is sent to the wrapper. This message includes the client's SC along with security credential (username/password) of the control center user.	Derived Keys, Client's SC, User/Password
			14	The wrapper asks its validation authority to validate the received client's SC.	
			15	The received client's SC is validated as truthful.	
			16	Validity of the received security credential (username/password) is asked from the user management system of the substation gateway operating system that is Microsoft Windows.	
			17	The Windows user management system approves the user identity and sends back the validation result.	
			18	Wrapper sends the ActivateSession Response to the client, and secure connection between the wrapper and client is established.	

There are two authentication mechanisms in the OPC UA security model: user authentication and application authentication. The user authentication is managed by creating a session which should be activated before using by presenting the user credential to the UA server (wrapper). Therefore, the user authentication in OPC UA consists of two steps: create session and activate session.

The other authentication mechanism is application authentication utilizing for creating secure communication channel in OPC UA security model. In OPC UA, an AIC is a unique security certificate for each UA application that is run on its respective device. This application instance certificate is used in order to identify the application and its related device while communicating to other distributed UA applications. All of the security certificates that are trusted by an application instance certificate are located in a special list which is called trust list. The Application authentication signifies that an OPC UA server/client checks the OPC UA client's /server's AIC and if the certificate is trustworthy, then AIC is authenticated and secure communication channel is established. Four authentication security categories are defined for UA applications [20]. Each category protects the system by providing certain level of security and has its own application area. Table III describes four security tiers that can be configured to UA applications.

TABLE III. SECURITY TIERS IN OPC UA APPLICATIONS

NO	Security Tiers	Explanation
1	NO Authentication	All valid certificates are trusted, and all OPC UA clients/servers are capable of communicating with the other parties. (No Security)
2	Server Authentication	All OPC UA clients trust a server. Clients are preconfigured by administrator to either put the certificate of server in the client's trust list or place the Certificate Authority (CA) which issues certificate for the server in the client's trust list.
3	Client Authentication	The OPC UA server just permits communication with trusted clients. Trust clients are who either have their certificates or the CA that issues certificate for them in the server's trust list.
4	Mutual Authentication	Both OPC UA client and server should be preconfigured by the administrator, and communication will be performed only between trusted peers. (Maximum level of security)

The mutual authentication is applied in our testing because the UA client and the UA wrapper are communicating via the public network. Configuring the mutual authentication assures that only the permissible UA clients are able to communicate with the trustworthy UA server. The additional security level can be achieved by using the firewalls and VPN connection between the substation and control center. The network access to the substation data network and control center network is controlled by firewalls [21]. The VPN creates a secure private link (tunnel) between substation and control center networks over the public Internet.

Although the OPC UA security specification is comprehensive and broad, but utilizing a VPN is also recommended since OPC UA security implementation in various stacks may contains some implementation flaws. In fact, applying a VPN connection adds another layer of security for transmitted data between substation and control center. In this experiment, a Point to Point Tunneling Protocol (PPTP) VPN [22] was also utilized for increasing security by creating a secure tunnel between substation LAN and control center network over the Internet. As a result, authentication is performed via the Extensible Authentication Protocol (EAP) during VPN connection establishment between substation and control center. Besides, OPC UA data is encapsulated in the in the payload of the PPTP packets, and secured two times: one time with the security protocols of the OPC UA security model, and additionally compressed and encrypted by the PPTP VPN protocols.

VI. CONCLUSION

In this experiment, reliable and secure OPC UA communication was established with real devices in the laboratory. The OPC UA security architecture enhances Internet communication security by creating login session, secure channel and socket connection between UA client in control center and UA server in the substation communication gateway. The substation gateway also applies the IEC 61850 standard to interact with IEDs within the substation data network. Accordingly, secure remote communication of OPC UA clients with substation IEC 61850 devices is enabled via the substation communication gateway.

Internet data communication between control center and modern substations must be protected against cybersecurity attacks in order to assure correctness of the exchanged data. The integrity of the transmitted data results in reliable and secure distribution network automation that finally leads to the safe and efficient smart grid.

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Publication 3

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Secure Communication of Smart Metering Data in the Smart Grid Secondary Substation

Peyman Jafary, Sami Repo
Department of Electrical Engineering
Tampere University of Technology
Tampere, Finland
Peyman.Jafary@tut.fi, Sami.Repo@tut.fi

Hannu Koivisto
Department of Automation Science and Engineering
Tampere University of Technology
Tampere, Finland
Hannu.Koivisto@tut.fi

***Abstract*— Smart Metering is considered as a critical infrastructure that collects low voltage network data for billing, management and automation applications in the smart grid. Secondary substation also plays significant role in the future smart grid and can participate in Smart Metering process. Reliable smart grid operation requires authentic metering data. Thus, Smart Metering data communication in Secondary substation must be protected against cyber-security attacks. This paper discusses Smart Metering architecture and security requirements, and then proposes utilization of the Secondary substation automation device for secure transmission of metering data from customer site to distribution network control center. The Secondary substation automation device provides security for communicating to customer site and control center via DLMS/COSEM security mechanisms and tunneled IEC 60870-5-104 data in PPTP VPN, respectively. Accordingly, customer metering data is securely transmitted to higher level information systems of the utility company via Secondary substation.**

Keywords—DLMS/COSEM; IEC 60870-5-104; secondary substation automation; smart grid; smart metering security

I. INTRODUCTION

Traditionally, the distribution network management was only based on Medium Voltage (MV) data without any focus on Low Voltage (LV) network data. In the smart grid distribution network, role of the LV network data becomes more important because of emerging new application areas such as Distributed Generation (DG), Renewable Energy Resources (RES) and customer automation. These new topics lead to the new network management model that is called Active Network Management (ANM) [1] in which LV network data is used for dynamic administration of the DG in the distribution network. In addition, LV network data is applied in Advanced Distribution Automation (ADA) applications at control center. ADA utilizes LV data as a new dimension for distribution automation resulting in remote monitoring and management of LV grid from control center [2].

LV network data is collected by applying advanced and intelligent metering systems. In order to implement effective ANM and ADA, collected LV data by metering systems must be trustworthy and protected against security attacks during transmission from LV network to upper levels of the distribution network. Several studies have been investigated cyber-security issues of intelligent metering and proposed security solutions [3],[4],[5].

The intelligent metering elements are distributed in different locations of the distribution network. One location could be Secondary substation that is utilized to transmit metering data to control center via SCADA communication protocols. This communication must be secured by implementing network and SCADA security techniques [6],[7].

This study considers Secondary Substation (SS) in Smart Metering procedure in which SS communicates with both smart meter and SCADA via DLMS/COSEM and IEC 60870-5-104, respectively. While DLMS communication is secured with internal security functions of the protocol, PPTP VPN [8] is used to protect IEC 60870-5-104 Internet communication. This paper is organized as follows: Section II explains smart metering architecture and security. Next, smart grid secondary substation and security is discussed in Section III. After this, secure communication of low voltage data is described in Section IV. Finally, conclusion is presented in Section V.

II. SMART METERING ARCHITECTURE AND SECURITY

The term Smart Metering implies a system that automatically measures, records, analyzes and controls customers' energy consumption with the aid of advanced measurement protocols and bidirectional communication technologies [9]. Smart Metering includes three main sections: Automated Meter Reading (AMR), Advanced Metering Infrastructure (AMI) and Automated Meter Management (AMM). Information security mechanisms are necessary in all the sections in order to operate reliable Smart Metering.

A. Smart Metering Architecture in Distribution Network

Smart Metering employs two-way communication between customer sites and control center. In Smart Metering, Home Energy Management System (HEMS) and Distribution Management System (DMS) are automation elements at customer premises and control center respectively.

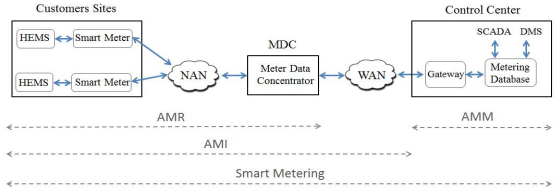

Figure 1: Smart Metering architecture in the distribution network

As can be seen in Fig. 1, data communication is bidirectional between all entities in the Smart Metering architecture. In customer site, smart meter exchanges data with HEMS from one side and with Neighborhood Area Network (NAN) [10] from other side. The HEMS is considered as the customer gateway that manages automation decisions [11] among smart equipment in the Home Area Network (HAN). Data from several smart meters is transmitted to the Meter Data Concentrator (MDC) via NAN.

Collected data in MDC is sent to the control center databases through Wide Area Network (WAN). In the control center, received data by Gateway is delivered to metering databases that are used for ANM and ADA applications. In fact, metering database is not just used for customer billing system. Additionally, metering database integrates to DMS and SCADA in order to provide new functions such as automatic demand response, integration of DERs to distribution network, and LV network monitoring and fault management.

B. Smart Metering Data for ANM and ADA

Smart meters are used not only for remote reading of customers' monthly consumption but also for transmitting LV network data (customer data) that is used for ANM and ADA. From ANM point of view, smart meters send LV power quality data first to MDC and subsequently to the metering database at control center. The ANM service (that could be a module in DMS) receives data from several MDCs as well as Distributed Energy Resources (DERs) data from the Aggregator [1] service. Then, the ANM service computes algorithms for Demand Side Management, power quality measurement and use of controllable energy resources.

Smart Metering also provides customer automation data for ADA. Customer automation is considered as a new dimension for modern distribution automation in which smart meters are able to indicate different LV network faults such as neutral conductor fault, blown fuse, over/under voltage and wrong phase order [2]. In fault condition, the message is sent to the metering database that makes DMS capable of automatic monitoring and disconnection of the faulty customer from LV network via the smart meter.

Therefore, Smart Metering data is utilized for multiple purposes in ANM and ADA. Authenticity of this data is very important for genuine functioning of the distribution network. Hence, Security requirements must be considered in communication protocol implementation, data exchange method and network design.

C. Smart Metering Security Requirements

Smart Metering communication starts from smart meter acting as an interface between customer data network and distribution data network. While data exchange in NAN is mostly carried out via metering communication standards, TCP/IP-based protocols are used in WAN communication. Secure Smart Metering communication provides valid data that result in dependable distribution network management and automation. In Fig. 1, different sections of Smart Metering have their own security issues and possible security threats.

Although IT security protocols can be applied for securing some parts of Smart Metering architecture, but exclusive security demands are also required in order to protect whole system [3]. In AMR, secure communication protocol must be used to ensure controlled access to meters as well as customers privacy protection. The AMI should be designed by considering network security technologies protecting AMI against cyber-attacks. Moreover, all collected data must be inspected before delivering to the AMM system that manages end-users data in protected databases.

Generally, the most important security aspects of Smart Metering are Confidentiality, Integrity, Availability and Accountability. Table I describes Smart Metering security requirements by taking the mentioned aspects into account [3].

TABLE I. SECURITY REQUIREMENTS OF SMART METERING IN THE DISTRIBUTION NETWORK

Smart Metering	Security	Requirements
AMR and AMI	Confidentiality	Privacy for transmitted data/commands in NAN and WAN. Privacy for customer data stored in MDC.
	Integrity	Exchanging of data/commands must only be limited to authenticated smart meters and legitimate MDC. Protection of transmitted data/commands in NAN and WAN against unauthorized access and modification. Unauthorized local and remote access to the MDC and smart meter must not be allowed.
	Availability	Availability of smart meter internal firmware and communication interface. Reliable data transmission in NAN and WAN. Availability for stored data in MDC.
	Accountability	Any change to the smart meter setting must be auditable. Data exchange of MDC with other applications should be accountable.
AMM	Confidentiality	Customer privacy protection by keeping all the databases private.
	Integrity	Access control for any local user/application/device/network connection accessing to the databases. Unauthorized network access to the AMM local network must be blocked. Access control for any remote user/application/device/network connection accessing to the databases. Authentication of MDC to the control center Gateway before exchanging data/commands.
	Availability	High database availability technologies for metering critical data.
	Accountability	All data transaction from metering databases to other applications should be recordable.

D. Smart Metering Security Solutions

There are various security solutions addressing the mentioned security requirements in Table I. Security solutions should be selected based on the devices capabilities, network media (wired or wireless), application requirements and cost.

Data confidentiality can be achieved by applying encryption algorithm that protects Smart Metering data communication against eavesdropping and traffic analysis. Ideally, communication protocols with built-in security functions should be selected for data communication. While the link layer encryption is used in NAN, encryption at the network layer, for example IPSec, is applied in WAN.

Data integrity is assured by using authentication techniques such as password authentication or public-key cryptography protecting Smart Metering communication against active security attacks including data alteration [12]. In NAN, each smart meter can be distinguished by a digital certificate that authenticates the smart meter to the authentication server that may place in the MDC location. In WAN, Secure Socket Layer (SSL) protocol and VPN could be used for securing data communication over Internet Protocol (IP). In the AMM network, access to databases is protected by password authentication and role-based access control.

Data availability in smart meter can be obtained by designing the firmware with diagnostic tool that automatically checks the smart meter communication interface and alarms for any error. In NAN, a reliable network design that meets timing requirement and resist against traffic overloads results in availability. Data availability of MDC can be enhanced by creating backup for the stored data, and input power redundancy for MDC. Redundant network connection (for example dual sim card in mobile network) and TCP/IP socket connection increase data availability in WAN communication. In control center LAN, network redundancy techniques such as ring topology along with the Spanning Tree Protocol (IEEE 802.1D) improve data availability. Furthermore, redundant databases can be used for high critical data.

Accountability solution includes timestamp information for control commands, received data to MDC and stored data in metering databases. Moreover, MDC and metering databases should audit logs in which all of the main data transactions with other applications are recorded.

A firewall and antivirus software also increase security by protecting the local networks in MDC location and control center from unauthorized network access and computer viruses. Furthermore, there are two other factors that affect Smart Metering communication security and should be regarded: HEMS security and physical security.

III. Smart Grid Secondary Substation and Security

Secondary Substation (SS) is the last stage in the process of delivering electrical energy from generation to end-users. Conventional SS mainly contains MV/LV transformer and fuses for protecting LV feeders without any automation functions. However, SS automation becomes more important in the smart grid and makes the SS capable of data communication with other parts of the distribution network. SS automation is achieved by applying programmable intelligent device that support automation and networking standards. This device, also known as Automation Unit (AU), provides intelligent functions from one hand and interaction of SS with the control center from other hand. Research projects such as INTEGRIS [13] and IDE4L [14] investigate requirements for designing the AU in the SS. First, AU should be cost-effective for applying in SS. Second, automation protocols for LV network management and monitoring should be supported by AU. Finally, AU should be capable of the Internet communication in order to exchange data with the control center over the utility Internet.

Implementing SS automation functions like real-time LV grid management require LV network data that is provided via Smart Metering. Therefore, some tasks of Smart Metering can be performed in SS. MDC location (in Fig.1) and SS are closest places to customer premises. Accordingly, MDC can operate as a part of AU in SS. Integration of MDC to AU adds database functionality to AU. The stored data in AU database can be used either locally (at secondary substation) or remotely (at control center) for ANM and ADA applications.

Incorporating SS automation in distribution network management and automation increases consistency in the whole distribution network. New approaches in distribution network administration propose distributed intelligence model [1] by shifting simple intelligent functions of ANM/ADA from control center to AUs at SSs. From Smart Metering data storage point of view, this means changing from centralized AMM databases at control center to the distributed databases at SSs. In other words, all of LV network data values are not sent from MDC to AMM and only messages contain calculated values are reported instead. The distributed intelligence model is more reliable since AMM databases are not the bottleneck of Smart Metering system for ANM/ADA decisions, and some of these decisions are autonomously made at SSs.

From information security point of view, local and network (Internet) access to AU must be controlled. Exchanging data with AU database must be restricted to authenticated customers (smart meters) and authorized applications at control center. Furthermore, appropriate access right (read/write) should be defined for the stored data in AU database.

IV. Secure Communication of Low Voltage Data

Regarding to the prior section, SS can be applied as the place for concentrating LV measurement data in Smart Metering. This becomes feasible by attaching MDC function to the AU. Thus, the AU should support both metering protocols and TCP/IP protocol for data communication in NAN and WAN respectively. The most common metering protocols in NAN are IEC 62056 DLMS/COSEM, IEC 61334 PLC and EN 13757 M-Bus. The Internet communication in WAN can be accomplished by SCADA communication protocols such as IEC 60870-5-104, DNP3, Modbus/TCP and. In the following, transmitting voltage data from smart meter to the monitoring application is carried out with real devices and applications.

A. Lab Setup Description

Smart Metering process is partly experimented by using the smart meter, SS supervision device and IEC 60870-5-104 (IEC

104) simulator. Smart meter measures customer voltage value and sends that to SS supervision device via DLMS protocol. Then, the SS supervision device (acts as AU with MDC function) transmits voltage value to the IEC 104 simulator via the Internet. This simulator can be considered as the control center SCADA. Fig. 2 shows devices layout and corresponded place in accordance with Smart Metering architecture.

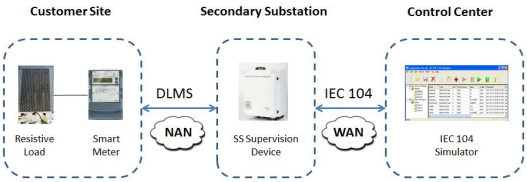

Figure 2. Lab setup Devices

In Fig. 2, smart meter offers DLMS/COSEM server for measurement data. The SS supervision device supports both DLMS/COSEM client and IEC 104 Controlled station that are connected to smart meter and IEC 104 simulator (IEC 104 Controlling station), respectively.

DLMS communication is performed via RS-485 serial connection that models NAN communication, and IEC 104 communication is carried out via the Internet that is considered as the WAN. Both smart meter (E650) and SS supervision devices (S760) are from Landis+Gyr [15]. The IEC 104 simulator is the software tool from Mitra software [16].

B. Security vulnarabilities in the Lab Setup

There are several security vulnerabilities in the lab setup before configuring security parameters. All the exchanged data/commands are transmitted as the plaintext in both NAN and WAN communication. This may expose transmitted data/commands to security attacks, particularly in WAN i.e. Internet communication. Moreover, smart meter and MDC are not authenticated each other. In WAN, unauthorized IEC 104 clients in the Internet can connect to MDC and send unrelated control commands to the smart meter.

In order to secure the lab setup, all the communication parties must be authenticated and exchanged data/commands must be confidential. DLMS/COSEM protocol includes security functions that can be applied for securing NAN communication but IEC 104 protocol has no built-in security mechanisms to create secure WAN communication. However, computer network security protocols can be used for protecting WAN communication of IEC 104 messages.

C. Security in DLMS/COSEM Protocol

Device Language Message specification (DLMS) is a general notion for abstract modeling of communication parties. COmpanion Specification for Energy Metering (COSEM) specifies collection of objects as the common language for metering data on top of DLMS. The combination is the IEC 62056 DLMS/COSEM that provides modeling, messaging and transporting of exchanged data between metering devices in the client-server architecture [17]. First, metering data and functions are modeled in the COSEM data model. Next, the modeled data is mapped to the Application Protocol Data Unit (APDU) and DLMS message is created. Finally, the produced message is transported by either High-Level Data Link Control (HDLC) or TCP (UDP) in serial communication or IP-based network, respectively.

In a DLMS/COSEM server, all the metering data and functions are structured using object modeling in which every quantity can be identified as a unique code in the OBject Identification System i.e. OBIS. OBIS code is meaningful sequence of six numbers in hierarchical structure, which is manufacturer-independent. Moreover, objects in COSEM data model can be organized in different manners and form Logical Devices (LDs). One physical device may include several LDs.

Information security in DLMS/COSEM protocol can be classified into four main categories: role-based access security, peer authentication, transport security and security logs.

In the first category, read and write access to COSEM data model elements (methods and attributes) is assigned to the clients based on their roles. Before accessing the LD in a server, clients require establishing an Application Association (AA) in order to identify the application context. Role-based security access to LDs can be defined in the server based on the established AA by the client. In other words, security policy is defined with respect to the AA. Role-based access security is carried out in two stages: first, visibility of server LDs to the clients is based on the established AA. When permissible LD becomes visible to the client, the second step is to define access right (read/write) for attributes and methods in the visible LD.

The second category is peer authentication that includes three [18] authentication levels: No Security (NS), Low Level Security (LLS) and High Level Security (HLS). NS is for public access without authentication. The LLS is unilateral password authentication in which the DLMS client must send password to the DLMS server. In HLS, mutual authentication is accomplished by exchanging security challenges between client and server i.e. challenge-response authentication. Both LLS and HLS take place during AA establishment and the AA is established only if authentication is successful.

The third security category is transport message security that happens after successful authentication and AA establishment. In this stage, COSEM data is mapped from data model to APDU in order to create DLMS/COSEM message for transmission. The payload (COSEM data) of this message can be either non-protected or protected by cryptographic algorithms in three ways: authenticated, encrypted and authenticated encryption. The Security Header (SH) is added to the protected messages and determines security policy of the message. Fig. 3 shows structure of a secured APDU by the authenticated encryption policy.

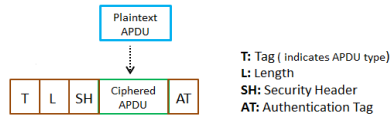

Figure 3. Secured APDU with Authenticated Encryption policy

DLMS/COSEM uses the symmetric cryptography suite for authentication and encryption algorithms: Galois Counter Mode (GCM) with AES-128. The AES-GCM-128 is utilized for both encrypting/decrypting APDU content and generating Authentication Tag (AT) that is appended to the end of the secured APDU. The AES-GCM-128 operation includes two actions: Authenticated Encryption (AE) and Authenticated Decryption (AD) [19]. The AE is performed by obtaining four inputs: secret key for encryption, initialization vector, plain text and additional authenticated data (this value is authenticated but not encrypted). The AD module first performs authentication and then generates plain text by receiving secret key for decryption, initialization vector, cipher text, additional authenticated data and further the Authentication Tag (AT) that is appended to the end of secured APDU.

The fourth security category is reporting AA events that provide accountability via security events logs. Any attempt for AA establishment (accepted/refused/unsuccessful) should be logged with timestamp.

D. Security in IEC 104Protocol

The IEC 60870-5 standard describes communication protocols for transmission of data and control commands in power system SCADA. The initial version of this standard is IEC 60870-5-101 (IEC 101) that discusses asynchronous data transmission over serial link. The last version is IEC 104 with same application layer as IEC 101but for communication over TCP/IP. IEC 104 contains object data modeling in which all required application data for power system SCADA are grouped in four main types of the information objects: Process, System, Parameter and File transfer information objects [20].

The IEC 104 APDU consists of two parts: Application Protocol Control Information (APCI) and Application Service Data Unit (ASDU). APCI contains control information for managing communication flow. Application data related to the above-mentioned information objects are carried inside ASDU in which every data element is uniquely addressed by Information Object Address (IOA) [20].

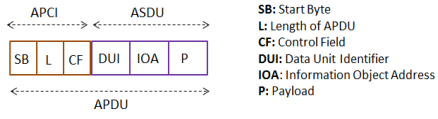

Figure 4. IEC 60870-5-104 APDU structure

In Fig. 4, all APDU sections including data payload (P) is transmitted as the plaintext without any security assignments. Consequently, this is not a safe protocol for public WAN communication i.e. Internet. However, IT security protocols, for instance VPN, can be used to improve security because IEC 104 APDUs are transported over TCP/IP networks.

E. Security Solutions for the Lab Setup

First all of the devices should be configured. Smart meter configures to run DLMS/COSEM server on RS485 interface and the physical HDLC device address is identified. Then, the Data Collection AA is defined.

The SS supervision device is configured to function as DLMS/COSEM client and IEC 104 controlled station. DLMS client is configured to request line voltage (OBIS: 1.1.32.7.0.255) from smart meter via serial port. Then, the voltage value is internally mapped to the IEC 104 data model.

The IEC 104 simulator is configured to operate as IEC 104 Controlling station for connecting to the SS supervision device, and request the mapped voltage value.

Security in DLMS communication is achieved via role-based access security and LLS authentication. The configured Data Collection AA only allows readout measurement data, and client application is not able to change (write) smart meter configuration. Furthermore, LLS authentication is configured for peer authentication. After successful authentication of the DLMS/COSEM client, Data Collection AA is established in which client is allowed to only to see measurement objects (including voltage value) with read data access right. There is no ciphering (message security) option for LLS authentication in the current version of the configuration software. As a result, client application is authenticated but messages are transmitted as the clear text in our experiment. However, in practice these messages must be sent as the cipher text.

Security in IEC 104 communication is assured via VPN connection. As it was explained earlier, IEC 104 messages are exchanged as the clear text and they require to be secured for Internet connection. In this experiment, we utilize Point to Point Tunneling Protocol (PPTP) [8] VPN for protecting IEC 104 Internet communication. Therefore, control center network must be first authenticated to the PPTP server at the SS network by sending username/password. After successful authentication, VPN connection is created and IEC 104 messages are wrapped within the VPN tunnel.

PPTP VPN applies Point-to-Point Protocol (PPP) [21] connections for transporting data between PPTP client at the control center and PPTP server at SS. PPTP VPN also uses Generic Routing Encapsulation (GRE) protocol that tunnels IEC 104 messages by incorporating them within PPP frames and encrypting PPP payloads i.e. IEC 104 messages. The PPP header and GRE header are added to the encrypted payload. These headers contain control data and tunnel information. Finally, the produced data frame is encapsulated within IP packet that includes new IP header. New IP header contains the IP addresses of PPTP client and PPTP server computers. In this way, all IEC 104 messages are encrypted and transmitted in a tunnel over the Internet.

Furthermore, firewalls are applied to protect control center and SS networks. All the incoming traffic is inspected by firewalls and any unauthorized network traffic is blocked. The SS firewall is configured to only allow PPTP VPN traffic (TCP port number 1723). So, all other Internet traffics are blocked and unknown IEC 104 Controlling stations are not allowed connecting to the SS supervision device via the Internet.

The above-mentioned security mechanisms were applied in order to fulfill the described requirements of the Table I for the lab setup. Figure below illustrates system components with explanations and general structure of the exchanged messages.

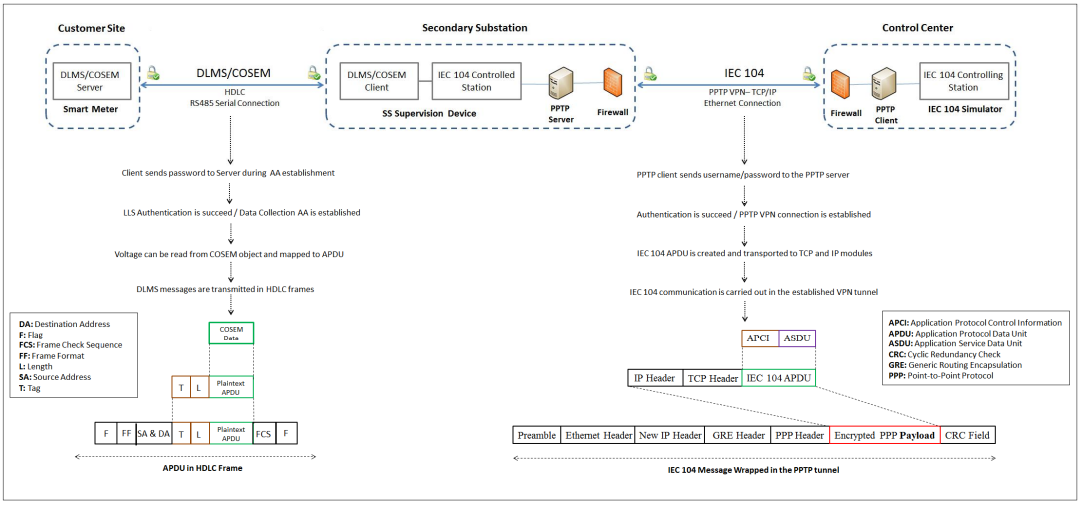

Figure 5. Explanation of Security solutions for the lab setup

V. CONCLUSION

This paper discussed secure LV data communication from customer place to monitoring application at control center via the SS automation device. This communication is accomplished in two main steps. First step includes voltage data communication from DLMS/COSEM server in smart meter to DLMS/COSEM client in the SS automation device. This communication is secured via the use of DLMS/COSEM protocol security functions. In the SS automation device, voltage value is mapped to IEC 104 and second step is started by integrating IEC 104 Controlled station into the remote IEC 104 monitoring software. PPTP VPN protects this Internet communication by encrypting IEC 104 messages.

Smart Metering is necessary for efficient collecting of data from LV network and delivering to utility information system. Security is an important parameter in Smart Metering communication that must be taken into account in the design, implementation and operation phases. Secure Smart Metering results in trusty distribution network management and automation.

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Publication 4

P. Jafary, S. Repo and H. Koivisto, “Security solutions for smart grid feeder automation data communication”, *In IEEE International Conference on Industrial Technology (ICIT)*, Taipei, Taiwan, March 2016.

Security Solutions for Smart Grid Feeder Automation Data Communication

Peyman Jafary, Sami Repo
Department of Electrical Engineering
Tampere University of Technology
Tampere, Finland
Peyman.Jafary@tut.fi, Sami.Repo@tut.fi

Hannu Koivisto
Department of Automation Science and Engineering
Tampere University of Technology
Tampere, Finland
Hannu.Koivisto@tut.fi

***Abstract*— Feeder automation creates automatic, fast and real-time power restoration during fault conditions in the distribution network. The most recent feeder automation solutions immensely decrease outage times through the use of smart field-devices interacting via communication network to perform feeder automation functions. The latest feeder automation methods use the utility Internet network for exchanging control information. This presents cybersecurity challenges and security measures must be employed to protect feeder automation data communication over the Internet. This paper discusses state-of-the-art feeder automation approaches and proposes security solutions for data exchange in each approach. Additionally, the lab setup is created to experience a modern feeder automation approach in which position of an overhead line disconnector is remotely controlled by transmitting IEC 60870-5-104 messages over the 3G Internet network. IPsec VPN in tunnel mode with Encapsulating Security Payload (ESP) is proposed for securing the lab setup. IPsec VPN implementation plus firewalls prevent unauthorized access and alteration of feeder automation data in the Internet. Consequently, distribution network reliability is enhanced.**

Keywords— distribution network reliability; fault management; feeder automation security; service availability

I. INTRODUCTION

Distribution Automation (DA) is realized by communication of automation software tools in the control center with the remote distribution components. In the smart grid, protection devices also participate in DA process via substation automation systems. Furthermore, modern protection devices provide required info for Fault Management (FM) during fault conditions. The main software tool for FM is Distribution Management System (DMS) that is located in the distribution network control center. DMS operates by integrating SCADA and distribution components information system. As a result, DMS presents new DA functions for the existing data.

Feeder Automation (FA) is a subsection of the DA that is used for several purposes [1] such as automatic transformer/feeder load transfer, load balancing, Volt/VAR optimization and FDIR (Fault Detection Isolation and Restoration). FA is especially actualized during FDIR [2] and logic selectivity [3] processes. Data exchange between FA elements can be made via SCADA communication protocols such as IEC 60870-5-104 or substation automation standards like IEC 61850.

Wireless Internet that meets real-time requirements is preferred as the communication channel for the smart grid FA approaches. Security issues become important for exchanging FA data over the utility Internet. Smart grid cyber-security requirements have been defined in NISTIR 7628 [4] including several use cases for DA security. One use case is related to FA in which generic security requirements have been mentioned for the FA data communication.

Applying security actions are required in order to ensure trusty operation of the FA applications. Internet security technologies [5] and SCADA communication protocols with in-built security functions [6] can be applied for securing the FA data communication but they should be selected with respect to the FA architecture, field-device capabilities and applied data exchange protocol.

In the rest of this paper, Section II describes medium voltage fault management. Next, security in feeder automation approaches is discussed in Section III. Finally, conclusion is provided in Section IV.

II. MEDIUM VOLTAGE FAULT MANAGEMENT

Distribution system operators try to administer their network in a manner that manages the occurred fault in the shortest possible time. FM process is accomplished in three main steps: fault detection, fault isolation and supply restoration. Fault detection is always realized by local protection system. Fault isolation is the critical part in which closest protection device to the fault should rapidly send trip signal to the circuit breaker to isolate the faulty section. In supply restoration step, topology of the distribution network is changed in order to minimize the isolated area.

In the last step, restoration time also depends on manual or automatic operation of feeder switching devices. Automatic switching of feeders (feeder automation) decreases restoration time and leads to higher electrical service availability.

A. Fault Detection via Modern Protection Systems

Electrical protection functions such as overcurrent, over/under voltage and earth fault protection are implemented in order to protect distribution network in fault conditions. Medium Voltage (MV) protection devices are located in the Primary Substation (PS) and in the location of overhead line disconnectors. Figure below depicts a distribution network with two MV feeders and the control center. Protection locations are highlighted with red dash lines.

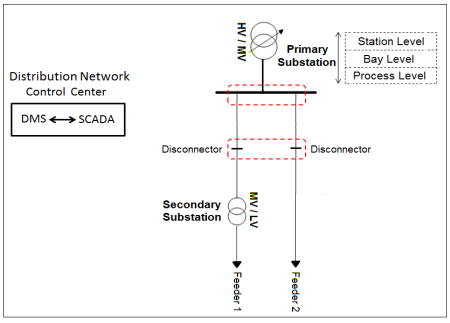

Fig. 1. Protection locations in the distribution network

First location of the protection devices is PS. Modern protections systems are tied to new Substation Automation Systems (SAS) operating based on the IEC 61850 standard. In Fig.1, the PS is IEC 61850-based substation with three logical levels: Process level, Bay level and Station level that include Sampled Value (SV) communication [7], GOOSE messages [8] and MMS communication [8] respectively. All data communication including protection data communication is accomplished via digital data network of IEC 61850 devices/applications within the substation LAN. Modern substation automation devices are called Intelligent Electronic Devices (IEDs) that are available with various functionality levels such as monitoring, control, measurement and protection [9]. IEDs support not only IEC 61850 standards but also IT networking protocols. Therefore, IED is considered as a significant component of the modern SAS.

There are two types of protection in PS: Decentralized Protection (DP) and Centralized Protection (CP) implementing in Bay level and Station level, respectively. While DP is carried out for primary (highly time-critical) protection via protection IEDs in Bay level, CP is employed as the backup protection and performed within Centralized Protection System (CPS) [10] in Station level.

In DP, protection IED receives measurement data from the substation LAN in form of digital SVs and computes time-critical protections such as overcurrent protection. Moreover, IEDs in Bay level exchange protection data such as interlocking and blocking signal via GOOSE messages.

CP is applied as the backup protection for lesser time-critical functions such as high-resistance earth faults, cross-country fault and breaker condition monitoring. CPS can be run inside the substation computer in Station level. CPS receives required data from Bay level IEDs via IEC 61850 MMS.

In Fig.1, the second location of protection devices is in the place of overhead line disconnectors that are equipped by IEDs with monitoring and control functionality. Recloser unit (recloser IED along with pole-mounted circuit breaker) is used in this place to protect MV feeder against momentary overhead line faults. Recloser IED is configured for several instantaneous trips pursued by delayed trip [11]. Reclosers units are usually applied in cooperation with sectionalisers in order to minimize outages in permanent fault condition. Sectionaliser is an overhead line disconnector with normal load-current breaking capacity that is located after recloser unit. It is used for isolating a section of the feeder after fault clearance by the upstream recloser unit [11].

Sectionaliser has internal counter that is increased when the recloser unit operates (opens). The recloser unit is reclosed in order to realize about the fault type (temporary or permanent). In case of temporary fault (fault clearance by the recloser), the sectionaliser's counter is reset. However, the counter is incremented when the fault is permanent. Once the number of counts reaches the preconfigured number, sectionaliser opens and downstream section of the feeder is isolated. If the fault location is in downstream of the sectionaliser, the power is restored to the upstream section by the recloser unit [11].

B. Fault Isolation and Service Continuity

In fault condition, protection IED sends trip signal to the circuit breaker in order to isolate the faulty section of the network. This results in electrical disruption within part of MV network because of radial distribution network topology. The number of industrial/residential customers that will be affected by the outage depends on the place of fault in the distribution network. Outage may lead to heavy losses by damaging customer equipment, particularly discontinuing industrial customers' processes. Thus, service continuity is very important and the outage duration must be as less as possible. Enhancing service availability (continuity) requires instant isolation of the faulty section and fast power restoration to the rest of network via backup feeders.

There are several solutions for increasing service availability applying in Design, Implementation and Operation phases. In Design phase, MV feeders should be designed in Open Ring Structure (ORS) in which feeder's topology is radial but structured as the ring with a normally open switch.

In Implementation phase, the protection IEDs must be accurately configured to be Selective that means minimum part of network should be isolated in fault condition. For instance in Fig.1, if fault occurred in Feeder 1, both Feeder 1 IED and Busbar IED see the occurred fault but only Feeder 1 IED should operate in order to prevent outage in the other feeder. Selectivity can be achieved by timing configuration of IEDs (time-based) or by blocking signal (communication-based).

In Operation phase, there are two approaches [9] for service availability enhancement: Fault Detection Isolation and Restoration (FDIR) and Logic Selectivity (LS). FDIR reduces duration of outages, LS severely decreases both duration and number of outages. Both FDIR and LS take advantages of automation and ICT functions of IEDs along with feeder

switching devices. LS method has higher performance in which fault isolation time is within the milliseconds range, but FDIR approach is accomplished in minutes. However, LS implementation requires high speed communication network and more sophisticated equipment.

FDIR operates based on the provided information by IED and coordinated interaction of outdoor devices with overhead line disconnectors. The main challenge in FDIR is automatic power restoration after fault location detection and isolation. In [12] various solutions have been proposed for FDIR.

LS functions by exchanging messages between substations IEDs, recloser IEDs and disconnector IEDs via highly efficient communication infrastructure with low latency. The exchanged messages can be based on proprietary [13] logic or standardized implementation [3][9] with IEC 61850 features. In IEC 61850-based LS, blocking messages are exchanged in form of GOOSE messages between IEDs in publish/subscribe mechanism via communication network. In a fault condition, IEDs in the faulty area publish/subscribe GOOSE messages and only faulty section is rapidly isolated by opening the circuit breakers/disconnectors placed exactly in upstream and downstream of the faulty area.

C. *Automatic Supply Restoration via DMS*

Modern FM can be automatically carried out via DMS in cooperation with SCADA, Network Information System (NIS) and Work Management System (WMS). In the following, FM steps are explained for the short-circuit fault between the Primary Substation and Disconnector 1 (D1) in Fig.2.

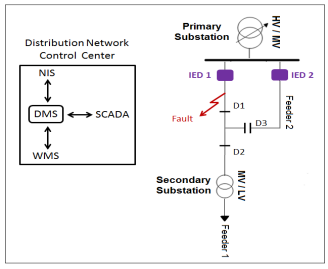

Fig. 2. Modern fault management in the distribution network

In the Primary substation, IED 1 opens feeder 1 circuit breaker and customers' electricity is disrupted. IED1 has measurement function and sends the measured-fault-current value to the SCADA via an event. Then, SCADA sends the measured-fault-current to the DMS that uses this value for automatic estimation of the fault location. DMS has access to the NIS including the faulty feeder (feeder 1) information. In NIS, calculated-fault-currents have been assessed for the feeder 1 in different zones: Primary substation to D1, D1 to D2, and D2 to Secondary Substation (SS). DMS compares the measured-fault-current with calculated-fault-currents, and the fault location is automatically estimated where two mentioned values are equal. Next, DMS executes intelligent restoration algorithm and requests SCADA to perform network reconfiguration by sending commands to remote disconnectors (opening D1and closing D3). Moreover, DMS requests WMS to automatically inform the field crew about the fault location via SMS/email/call. In this approach, fault isolation and power restoration to customers are accomplished in several minutes. Modern FM is fast and efficient but requires more investments in feeder switching devices which must be capable of communication with the remote Control Center (CC). Combining automation and communication features of these devices lead to automatic switching of MV feeders (feeder automation) that will be discussed in the next part.

D. *Feeder Automation Approaches*

FA improves distribution network reliability. Reliability is one of the important factors for evaluating utilities efficiency and can be analyzed via the use of reliability analysis software [14]. This software is applied for determining the optimal quantity and place of remote-controllable disconnectors, and also calculates reliability indices. The most popular reliability indices are SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index). While SAIFI notes to the outage occurrence rate, SAIDI and CAIDI pertain to duration time of the outage.

The most challenging issue within reliability analysis process is determining the outage time for restoring power supply to different sections of the network [14]. FA reduces restoration time and improves some reliability indices (SAIDI and CAIDI). FA is often fulfilled during FDIR and LS. So, FA approaches depend so much to the FDIR/LS solution and place the restoration algorithm (making FA decisions) has been located. Generally, there are four [1][2][11] FA approaches: Semi-Automatic, Centralized, Decentralized and Distributed.

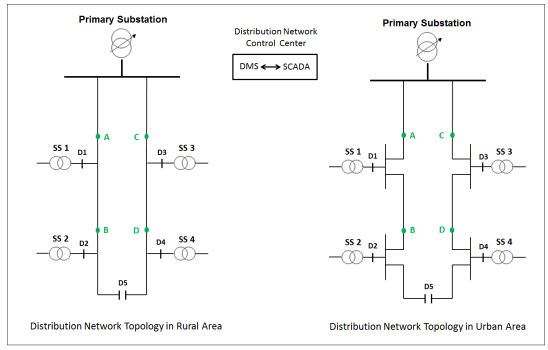

Fig. 3. Feeder automation in the distribution network

In the following, FA approaches are briefly explained with respect to Fig.3 including two feeders in ORS. First, required devices for FA approaches are pointed out in Table I. These devices are proposed to achieve highest network reliability in each approach. However, in practice some of the proposed devices may change (for example some reclosers are replaced with disconnectors) based on factors such as optimum cost, actual application requirement and load criticality level.

TABLE I. REQUIRED DEVICES FOR FEEDER AUTOMATION APPROACHES

	A	D1	B	D2	C	D3	D	D4	D5	PS	CC
Semi Automatic	Recloser	----	Sectionaliser	----	Recloser	----	Sectionaliser	----	----	----	----
Centralized	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Remote I/O RTU	IED	Agent
Decentralized	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Recloser	Remote I/O RTU	Remote I/O RTU	IED Agent	----
Distributed	Recloser Agent	IED Agent	Recloser Agent	IED Agent	Recloser Agent	IED Agent	Recloser Agent	IED Agent	IED Agent	----	----

In Table I, recloser signifies recloser unit i.e. recloser IED along with pole-mounted circuit breaker. Semi-Automatic solution only contains recloser and sectionaliser that provide local automation as it was discussed in Section II part A. The automaticity of this approach is only relied on built-in logic inside the sectionaliser's counter. All reclosers, sectionalisers and Disconnectors (D1to D5) operate locally in the field. The advantages of this approach are simplicity and low cost operation. Disadvantage is limited implementation of FA functions because of lacking data communication network.

Centralized approach contains Recloser, Remote I/O module, RTU, IED in PS and Agent software (restoration algorithm) in CC. Reclosers are used for clearing momentary faults and they are remotely controllable via SCADA communication protocols. In permanent fault conditions, IED reports required data to the CC agent that makes restoration decision and sends required control commands (open/close) to the overhead line disconnectors (D1 to D5) via in-field RTUs (and subsequently to remote I/O modules). All of the disconnectors must be remote-enabled disconnectors. In this approach, there is single centralized agent that covers FA decisions for all the supervising feeders in the CC. A possible place for the agent is in the DMS application as it was explained in Section II part C. The advantage of this approach is ability to fully implement FA functions. The drawbacks are complexity and weak reliability because agent is the bottleneck for all FA decisions in the whole CC supervising area.

Decentralized method is similar to Centralized approach but agent function (restoration algorithm) is decentralized to substations level. In other words, there is an agent in each PS that handles FA for its own substation feeders. A possible place for the agent software is CPS at substation Station level that was mentioned in Section II part A. The benefits of this approach are nearly full implementation of FA functions, medium scalability, and higher reliability because agents are distributed and there is no single-point-of-failure for FA decisions in the entire supervised distribution network. The drawback is higher cost for implementing agent software in every Primary substation.

In Distributed approach, restoration and FA decisions are neither made at CC nor at PS but autonomously in the field. Previous approaches (Centralized and Decentralized) included in-field dumb RTUs that are only capable of obeying FA decisions made by the remote agent. However, Distributed approach utilizes in-field IEDs supporting not only intelligent functions for making decisions but also advanced ICT for communication. All of disconnectors (D1 to D5) are controlled by IEDs instead of RTUs. Distributed approach can be implemented by applying IEC 61850 GOOSE messages exchanging between recloser IEDs and disconnector IEDs as it was mentioned in Section II part B. Particular Logical Nodes for FA are proposed in IEC 61850-90-6. The advantages of this approach are high scalability (adaptation of system for adding new IEDs), autonomy (decisions are made locally) and robustness (failure of one element does not break entire process). Disadvantages include high cost because of using IEDs instead of RTUs, and requirements for implementing high performance communication network.

Distributed approach can also be realized in agent-based architecture. Agents are incorporated in each IED to distribute intelligence in device level. This leads to a multi-agent system that is loosely-coupled network of entities interacting with each other to solve a FA challenge. FA decisions can be executed by combining IEC 61850 data model with EC 61499 function blocks via a multi-agent architecture [15] [16]. There is no global system control in multi-agent architecture. So, FA decisions are distributed and concurrently made by the distributed agents via sophisticated patterns of interactions.

III. SECURITY IN FEEDER AUTOMATION APPROACHES

Apart from Semi-Automatic approach, implementation of all other approaches requires data communication network. In fact, communication is the essential component for the

discussed approaches. The most recent smart grid communication solutions propose applying open standards and Internet-based communication for DA applications including FA approaches. This communication can be carried out via wired networks or wirelessly. Wireless communication such as cellular network and WLAN are being considered as the preferred technologies for Internet communication inside FA approaches. Therefore Field Communication Gateway (FCG), for instance an industrial 3G router, is required for Internet communication of in-field RTU/IED with PS, CC or each other. Although, the Internet communication presents several benefits but on the other hand cyber-security becomes a challenge for FA data communication. Securing this communication indirectly improves electrical service availability by ensuring correct FA operation.

A. Security Vulnerabilities in FA Data Communication

There are security vulnerabilities in the Internet-based communication of Centralized, Decentralized and Distributed approaches. Subversive electric outage may happen by unauthorized application sending unrelated commands to the in-field RTUs/IEDs to malfunction overhead line disconnectors. Additionally, Denial-of-Service (DoS) attack can also happen by the attacker targeting unprotected FA application server (for example DMS) in the CC or PS. Moreover, transmitted data may be exposed to security attacks such as eavesdropping and traffic analysis if data/commands exchanged in plaintext format. Thus, information protection mechanisms are necessary in order to assure dependable functioning of FA applications which eventually results in reliable distribution network automation. In FA data communication, the most critical security requirements are first integrity, next availability (high-critical for control and less-critical for monitoring) and then confidentiality [4].

B. Security Solutions for FA Approaches

As it was mentioned, FCGs are applied for Internet communication of in-field devices with remote application/device. FCG must support network security technologies such as firewall and VPN in order to provide data integrity and confidentiality in FA approaches. Data availability can also be assured by using highly efficient communication network, reliable communication protocol and dual communication link (for example redundant SIM cards to increase network availability) in FCGs. In the following, security solutions for each approach are proposed.

In Centralized/Decentralized approaches, security solutions are based on security devices in both CC/PS and remote field. In CC/PS, network communication with the situated agent software is secured by applying firewall, VPN server and Communication Management Gateway (CMG). Firewall only allows VPN traffic with FCGs. Secured VPN connection is established after authentication of the FCG (VPN client) to the VPN server in CC/PS. CMG is a master unit exchanging data with in-field RTUs via SCADA protocols. The CMG must contain two Ethernet ports: remote Ethernet port for Internet communication of SCADA protocol and local Ethernet port for communication with the agent in CC/PS LAN. This provides security by isolating external and internal data traffic in CC/PS.

Furthermore in the remote field, FCG must be equipped with built-in firewall and remote access VPN client. The firewalls are configured to only allow incoming VPN traffic from the CMG remote Ethernet port. Another layer of security can be achieved by applying secure version of SCADA communication protocols between in-field RTUs and CMG, for example OPC UA security instead of OPC UA [6].

In Distributed approach, security relies on two items: FCGs and communication protocol security mechanisms. FCGs are attached to the field IEDs and make them capable of secure communication over the utility Internet. FCGs must support firewall and specific type of VPN. In this approach, security via VPN is challenging because of GOOSE messages exchanging between IEDs. GOOSE messages are ISO layer 2 messages and there are challenges for not only transmitting the layer 2 GOOSE messages over the Internet [17] but also requirements for specific VPN (layer 2 tunneling) that securely transmits ISO layer 2 messages over the utility Internet.

The second item provides security for Distributed approach is communication protocol security mechanisms. This depends to the communication protocol in the Distributed approach application. In case of employing GOOSE messages, security can be enhanced via digitally sign of GOOSE messages by implementing the IEC 62351-6 standard.

C. Lab Setup forSecuring Decentralized Approach

In the last section, a secure solution for Decentralized approach is proposed and implemented. Furthermore, a FA scenario is partially tested within the proposed architecture by communication of PS with one remote point over the Internet.

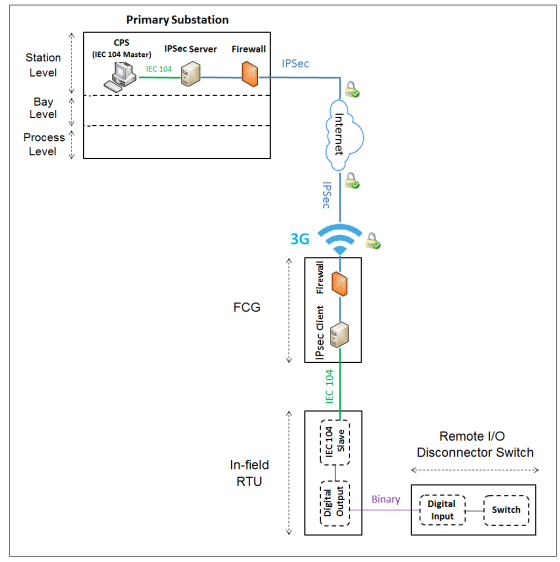

Fig. 4. Secure architecture for Decentralized feeder automation approach

Fig.4 indicates applied devices/applications in the lab setup. In our experiment, the goal is to remotely close the overhead line disconnector from an application in PS via secure Internet communication. This experiment is in accordance to Decentralized approach. So, agent is located inside PS. A possible place for installing the agent software can be CPS. Since our focus is on data communication and we do not have agent (restoration algorithm) software, alternatively the IEC 60870-5-104 (IEC 104) Master application [18] is used inside the CPS that is essentially a personal computer. Basically, every agent calculates restoration algorithm (making FA decisions) and requires an additional software module for executing FA decisions (for example SCADA in PS). The IEC 104 Master application is applied for this purpose in order to execute (send) control command to close position of the remote overhead line disconnector.

IEC 104 is a communication protocol that is used in electric power systems SCADA. This protocol has been designed to transport messages over TCP/IP networks and can be applied for Internet communication in Decentralized approach. The IEC 104 Master sends the IEC 104 control command to the in-field RTU [19] that supports IEC 104 Slave. The IEC 104 command is defined to turn on a digital output in the RTU.

Internet communication between IEC 104 Master in CPS and IEC 104 Slave in RTU is carried out via FCG device [20]. This device is an industrial 3G router that supports not only Internet protocols but also security technologies such as firewall and IPsec VPN client.

An overhead line disconnector (switch) is simulated in the Real Time Digital Simulator (RTDS) [21]. The switch position is closed when the binary signal is received from the RTU digital output (initially triggered by the remote IEC 104 Master) to the RTDS digital input. The RTDS digital inputs are corresponded to the Remote I/O module in the Decentralized FA approach.

Secure infrastructure for Decentralized FA data communication is provided by firewalls and IPsec VPN. Firewalls control network traffic to/from CPS and FCG, and block Internet connections from untrusted devices. IPsec VPN provides integrity and confidentiality for data communication. First, FCG IPsec client establishes a secure tunnel with the PS IPsec server. Then, the IEC 104 Master securely sends control commands (turn on a digital output) to the RTU IEC 104 Slave over the Internet. In fact, the IEC 104 control commands are wrapped within the created VPN tunnel.

D. Analyzing Communication Security in the Lab Setup

IPsec [22] is a layer 3 tunneling protocol that provides seamless security for exchanging IEC 104 messages. IPsec is a vastly modular protocol giving users ability of selecting various security policies. IPsec consist of three main components: Authentication Header (AH), Encapsulating Security Payload (ESP) and Internet Key Exchange (IKE). AH only ensures integrity (and authentication) of IP packets by performing hash algorithm. ESP provides all of AH security services as well as symmetric key encryption for data confidentiality. IKE is applied for negotiating security policies and generating a secret key for exchanging data. Basically, IKE operates in two phases. Phase 1 is related to negotiation of two peers in order to establish a common Security Association (SA) for a session. SA specifies encryption/authentication algorithms, security policies and lifetime of the session. In order to securely create SA in phase 1, both peers are authenticated and securely communicate through the use of public-key cryptography. In the phase 2, a custom secure channel is created by generating private key for data communication and exchanging VPN tunnel parameters. Both phases apply Diffie–Hellman key exchange method for establishing a shared key.

As it was stated, there are two types of IPsec Header: AH and ESP. These IPsec Headers can be propagated in two modes: Transport and Tunnel. While IPsec header is added to the original IP header in Transport mode, both IPsec header and original IP header are incorporated within a new IP packet in Tunnel mode. So, Tunnel mode includes new IP header.

As can be seen in Fig.4, IEC 104 messages are used for experiencing Decentralized approach. Essentially, there are no built-in security functions inside IEC 104 standard and IEC 104 messages are transmitted as the plaintext over TCP/IP. This is the main security vulnerability for Internet communication of the IEC 104 messages in Decentralized approach. In our experiment, IPsec in Tunnel mode with ESP are applied in order to offer maximum security for Internet communication. Figure below illustrates securing of IEC 104 messages within the IPsec VPN tunnel.

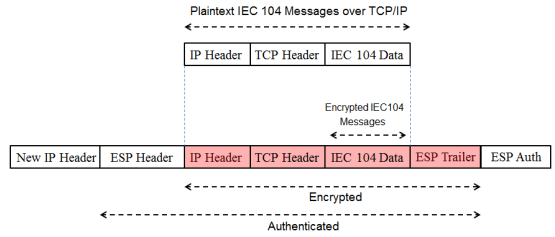

Fig. 5. IEC 104 messages wrapped and secured in IPsec VPN tunnel

In summary, the following security functions are applied to protect data communication in our experiment:

- Firewalls in PS and FCG only allow IPsec communication and block other network traffic.
- Secure IPsec tunnel is established after successful authentication of IPsec client and IPsec server by exchanging security certificates during the phase 1 of

IKE. Cryptographic algorithms are also used for secure transmission of these digital certificates.

- Hash function (integrity), authentication and encryption of data packets via ESP in IPsec tunnel. ESP not only encrypts IEC 104 data/command but also original IP and TCP addresses of data frames.
- In ESP header, there is a Sequence Number field that prevents malicious/fraudulent repetition of FA data transmission.
- Isolating internal network from external network (Internet). Both CPS and in-field RTU have private IP addresses but communicate over the Internet. Only IPsec server [23] and IPsec client [20] devices have public IP addresses. Both of these devices support routing function.
- In-field RTU has IEC104 filtering option. So, RTU is configured to only communicate with the CPS private IP address. In this way, other IEC 104 master applications inside substation LAN are not allowed to communicate with the RTU.
- The FCG supports two SIM cards. The second SIM card can also be used to maximize network availability.

The described items fulfill the security requirements for Internet communication of IEC 104 messages in Decentralized FA approach of the lab setup.

IV. Conclusion

In the lab setup, a secure solution for Decentralized FA data communication was proposed and tested with real devices and applications. IPsec tunnel implementation provided data confidentiality, data integrity, data origin authentication and peer authentication. These mechanisms protect Internet communication of FA data against security attacks such as data alteration, eavesdropping, IP address spoofing, replay attack, Denial-of-service attack and man-in-the-middle attack. Furthermore, reliable communication was also obtained by transporting IEC 104 messages over TCP that is a connection-oriented transport protocol.

FA approaches can be compared with multiple parameters such as cost, flexibility, scalability and complexity. Information security mechanisms must also be taken into account during selection and implementation of the FA approaches. Secure FA data communication results in greater reliability in the electrical distribution network.

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Publication 5

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Secure Layer 2 Tunneling Over IP for GOOSE-based Logic Selectivity

Peyman Jafary, Ontrei Raipala, Sami Repo
Department of Electrical Engineering
Tampere University of Technology, Tampere, Finland
Peyman.Jafary, Ontrei.Raipala, Sami.Repo@tut.fi

Mikko Salmenperä, Jari Seppälä, Hannu Koivisto
Department of Automation Science and Engineering
Tampere University of Technology, Tampere, Finland
Mikko.Salmenpera, Jari.Seppala, Hannu.Koivisto@tut.fi

Seppo Horsmanheimo, Heli Kokkoniemi-Tarkkanen, Lotta Tuomimäki
VTT Technical Research Centre, Helsinki, Finland
Seppo.Horsmanheimo, Heli.Kokkoniemi-Tarkkanen, Lotta.Tuomimaki@vtt.fi

Amelia Alvarez, Francisco Ramos, Alessio Dede, Davide Della Giustina
Schneider Electric (Seville, Spain) - Unareti (Milan, Italy)
Amelia.Alvarez, Francisco.Ramos@schneider-electric.com
Alessio.Dede, Davide.Dellagiustina@unareti.it

***Abstract*—Logic Selectivity immensely reduces both number of outages and their duration in the distribution network. IEC 61850 can be applied for standard implementing of Logic Selectivity in which Generic Object Oriented Substation Events (GOOSE) messages should be exchanged between intelligent field devices over the Internet. However, information security and automation requirements must be noted in order to ensure secure and accurate operation of Logic Selectivity. This paper describes lab setups for analyzing functional and non-functional characteristics of GOOSE-based Logic Selectivity. Layer 2 tunneling over IPsec is proposed for GOOSE communication over 4G Internet. Data integrity and confidentiality are achieved via IPsec in Transport mode. Furthermore, communication impact on Logic Selectivity performance are investigated by the software tool measuring communication network quality.**

Keywords— distribution automation security; IEC61850; layer 2 tunneling over IPsec; logic selectivity

I. INTRODUCTION

Distribution network automation includes various new functionalities such as Logic Selectivity. Motivation for Logic Selectivity is Distribution System Operator regulation which allows to make higher profit if service availability is improved. Logic Selectivity [1] considerably decreases outages number and duration by obtaining benefits from the advanced feeder automation [2] and communication technologies. In order to achieve full benefits of Logic Selectivity, investment is required in telecontrollable switching devices, Intelligent Electronic Devices (IEDs), and communication network for exchanging messages between IEDs. These messages can be based on the proprietary protocol [3] or with respect to the standard IEC61850 data model [4][5]. IEC61850-90-6 draft proposes Logical Nodes applying for Logic Selectivity. GOOSE [6] messages are exchanged between IEDs in standardized Logic Selectivity.

Wireless Internet that fulfills the automation real time requirements is preferred as the communication channel for exchanging GOOSE messages between IEDs in Logic Selectivity. GOOSE messages are OSI model layer 2 Multicast messages. Layer 2 tunneling over IP (Internet Protocol) can be applied in order to tunnel GOOSE messages in the Internet. IT and automation security are important aspects that must be noted for authentic and precise operation of Logic Selectivity. Information integrity and confidentiality must be added to the layer 2 tunneling communication. Furthermore, IEDs must be connected to high speed Internet connection with low latency and deterministic behavior that guarantees on-time delivery of GOOSE messages between IEDs.

This study examines Logic Selectivity functions and its impact to the distribution network reliability by improving SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index). Furthermore, feasibility of applying layer 2 tunneling for Logic Selectivity GOOSE communication in the wireless Internet (4G/LTE mobile connection) is investigated. Information security and automation requirements of this communication is analyzed with the aid of PICARD [7] model and QoSmet [8]. This paper is organized as follows: Section II discusses logic selectivity functionality. Then, layer 2 tunneling protocol is described in Section III. Next, Section IV explains test setups. After this, test results analysis is explained in Section V. Finally, conclusion is presented in Section VI.

II. LOGIC SELECTIVITY FUNCTIONALITY

Utilities always seek new solutions to maximize their service availability. One solution is Logic Selectivity.

A. Protection Selectivity

Logic Selectivity is fundamentally tied to the concept of protection Selectivity. This means protection IEDs must be operated in a manner that minimum part of the distribution network be isolated in fault condition. Selectivity between protection IEDs can be configured via two main methods: time-based and communication-based. Time-based Selectivity is accomplished by setup the operation delays between IEDs. Communication-based Selectivity is performed by exchanging the blocking [9] signal between IEDs. Communication-based

Selectivity has been evolved from electrical copper wire to optical fiber cable to Ethernet cable.

Logic Selectivity is used in urban areas and aims to reach complete Selectivity in all sections of the distribution network. IEC61850-based Logic Selectivity utilizes Ethernet Communication-based Selectivity and standard blocking messages in form of GOOSE. In fault condition, IEDs publish GOOSE messages and executes an intelligent algorithm that results in Selective operation of the IEDs.

B. IEC61850-based Logic Selectivity Algorithm

Summary of the IEC61850-based Logic Selectivity algorithm [10] is explained in Table I.

TABLE I. SUMMARY OF THE LOGIC SELECTIVITY ALGORITHM

Stage	No	Algorithm Steps Description
Fault Isolation by Circuit Breakers (CBs)	1	Every substation IED receives and stores current/voltage values of its attached CB/SW. (MMXU Logical Node)
	2	In fault condition, overcurrent is detected by all upstream IEDs that have attached to CBs. (PTOC Logical Node)
	3	All respective IEDs publish GOOSE blocking message.
	4	Every upstream IED (that control the CB) subscribes to the published GOOSE messages by the downstream IEDs. (ALSM Logical Node)
	5	All the respective IEDs wait for the time T1 that is equal to 100ms plus an additional time. The additional time for each IED is calculated based on the number of its GOOSE subscriptions to the downstream IEDs.
	6	For each IED, protection is not operated if any GOOSE block message received during T1. In other words, the IED waits for isolating the fault by the downstream IED.
	7	After expiring T1, each IED rechecks for the overcurrent. Protection in the closest IED to the fault (that has not subscribed to any GOOSE message) is Selectively operated because this IED has the smallest value for T1. After IED operation, its attached CB is opened.
Fault Isolation by Switches (SWs) & Service Restoration	8	After opening closest CB to fault, all the related IEDs (that have attached to SWs) see fault passage indication and under voltage. (SFPI and PTUV Logical Nodes)
	9	All the related IEDs publish GOOSE blocking message.
	10	Every upstream IEDs (that control the SW) subscribes to the published GOOSE messages by the downstream IEDs. (ALSM Logical Node)
	11	All the related IEDs wait for the time T2 that is equal to 100ms plus an additional time. The additional time for each IED is calculated based on the number of its GOOSE subscriptions to the downstream IEDs.
	12	For each IED, the SW is not operated if any GOOSE block message received during T2. In other words, the IED waits for SW operation by the downstream IED.
	13	After expiring T2, each IED rechecks for the downstream switch operation. SW operation in the closest IED to the fault (that has not subscribed to any GOOSE message) is carried out because this IED has the minimum value for T2. After IED operation, its attached SW is opened.
	14	The opened CB (nearest to the fault) is automatically reclosed by its attached IED after passing the reclosing time (T3). T3 value is 30 seconds. (RREC Logical Node)
	15	After reclosing the CB, the service is restored to the rest of the network if the faulty section has isolated.

All the substations should be equipped with IEDs and controllable CBs/SWs. The algorithm includes three main stages: fault isolation by CB, further minimizing the faulty section by SW, and service restoration by reclosing the opened CB. In order to execute the algorithm, GOOSE messages must be exchanged between the substations over the Internet. Layer 2 tunneling over IP can be used for this purpose.

III. LAYER 2 TUNNELING PROTOCOL (L2TP)

Layer 2 Tunneling Protocol version 3 (L2TPv3) [11] enables integration of Ethernet segments over routed IP network. With it, automation LAN segments can be merged to a single logical LAN. Therefore, GOOSE messaging that is based on Ethernet multicast type communication can be extended between distant IEDs. Motivation to use L2TP comes from Software Defined Networking (SDN) point of view which is a modern way to manage and alter topology of complex network infrastructures without a need to actually alter the physical network cabling. This kind of virtualization of networks is especially essential in the future smart grid where all relevant elements participating in operations are not necessarily owned by a single company. In case of Logic Selectivity, layer 2 tunneling enables to bridge the substations into each other, utilizing existing networking infrastructure and even the Internet. L2TP in itself is a VPN solution without encryption or strong authentication. These must be added by using some other protocol like IPsec [12].

Implementing L2TP will have a negative influence on communication quality as 1) tunnel requires additional headers affecting the maximum payload and data traffic amount, 2) intermediate networks and edge routers cause undeterministic delays and 3) especially in mobile networks the reliability of communication path decreases. Additionally, L2TP uses UDP/IP based transmission of tunneled information and can lead to problems typical to UDP, namely packet loss. If IPsec security is also applied, additional headers and processing are incurred. But as most equipment have hardware support for crypto processing, this additional performance cost is assumed to be insignificant. These are the key factors to be considered deciding applicability of L2TP in each use case.

IV. TEST SETUPS

In this Section, lab setups are built for testing Logic Selectivity functional and non-functional characteristics.

A. Lab Setup for Logic Selectivity Functional Testing

The experiment contains a distribution network with four substations: one Primary Substation (PS) and three Secondary Substation (SS1 to SS3). PS is the substation for transforming High Voltage (HV) to Medium Voltage (MV). SS contains transformer for converting MV to Low Voltage (LV).

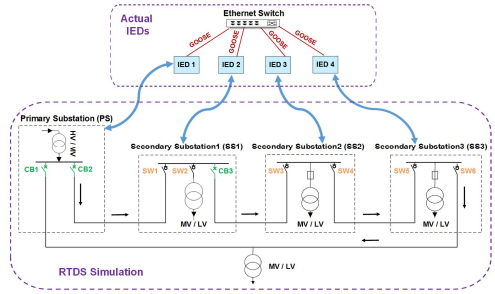


Fig. 1. Layout of the lab setup for Logic Selectivity functional testing

In order to implement Logic Selectivity, it is necessary to use IEDs in all the substations (both PS and SSs). Moreover, applying circuit breaker (instead of switch disconnector) in one of the SSs is recommended. The test includes electrical network real-time simulation and advanced IEDs that support IEC61850 Ethernet Communication-based Selectivity.

The electrical network model including transformers, busbars, feeders, Circuit breakers (CBs) and Switch disconnectors (SWs) are designed and simulated in Real Time Digital Simulator (RTDS) [13]. RTDS simulates the electrical network model in real-time and this makes it possible to connect actual IEDs [14] to RTDS as hardware-in-the-loop simulation. In RTDS simulation, every substation is equipped with one IED that is externally connected to RTDS.

Both RTDS and IEDs have input/output terminals for both analog and digital signals. Analog terminals are applied for transmitting voltage and current values of the simulated network from RTDS to the IEDs. Additionally, Digital terminals are used for sending/receiving of the status/command signals between the RTDS and IEDs. After configuring the lab setup, every substation IED receives current and voltage values of the CB/SW in its substation. Furthermore, position (open or close) of every CB/SW in a substation can be controlled by its IED that has connected to RTDS.

After running the simulation (Fig. 1) in RTDS, all the CBs and SWs are normally closed except CB1 (backup feeder) that is normally open. Moreover, all the IEDs control either CB (CB controller) or SW (SW controller) except IED 2 that functions as both CB controller and SW controller. In order to evaluate Logic Selectivity performance, the fault logic is also designed in RTDS. The fault logic allows simulating different type of (phase, 3-phase and neutral short-circuit overcurrent) fault in different locations of the simulated network model.

The IEDs support required IEC61850 Logical Nodes and ISaGRAF [15] technology for defining the mentioned Logic Selectivity algorithm. After defining the algorithm, overcurrent protection settings (current and time thresholds) are configured for each IED. Then, GOOSE subscription is designed between IEDs based on the power flow direction and location of each IED in the network. Power flow direction is from PS toward SSs and every upstream IED subscribes to the published messages by downstream IEDs. GOOSE subscription (by activating ALSM logical nodes) is configured to the IEDs as: CB2 controller (in IED1) subscribes to CB3 controller (in IED2); SW1 controller (in IED2) subscribes to SW3,4,5,6 controllers (in IED3 and IED4); SW3 controller (in IED3) subscribes to SW5,6 controllers (in IED4); and SW4 controller (in IED3) also subscribes to SW5,6 controllers (in IED4).

B. Lab Setup for Logic Selectivity Non-Functional Testing

In this section lab setup is made for non-functional testing i.e. testing security and automation requirements. In Fig.1, Ethernet switch was used for exchanging GOOSE messages between IEDs. In real applications, however, IEDs are located in distant substations and communication network is required for exchanging GOOSE messages between IEDs. Wireless Internet is the latest trend for the IEDs communication.

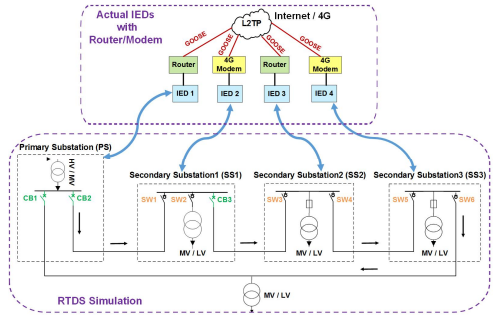


Fig. 2. Layout of the lab setup for Logic Selectivity non-functional testing

Applying layer 2 tunneling over IP, i.e. L2TPv3, is proposed for communication of layer 2 GOOSE messages in the 4G Internet. In Fig. 2, the Router (Cisco 892) [16] and 4G/LTE Modem (Cisco 819) [17] support layer 2 tunneling over IP and connect IEDs to the Internet.

V. TEST RESULTS ANALYSIS

In this Section, Logic Selectivity performance as well as security and automation requirements for correct operation of Logic Selectivity are investigated.

A. Results Analysis for Functional Testing

Logic Selectivity algorithm for the lab setup (Fig. 1) was tested and verified for the permanent overcurrent fault in different locations. The results are presented in Table II.

TABLE II. RESULT OF LOGIC SELECTIVITY (WITH AVERAGE TIME VALUES)

Area	Fault Location	Description of Result
Area 1	PS to SS1	CB2 is opened by IED1 (146ms after starting fault).
Area 2	SS1 to SS2	CB3 is opened by IED2 (146ms after starting fault).
Area 3	SS2 to SS3	First, CB3 is opened by IED2 (after 146ms). Next, SW4 is opened by IED3 (after 1.817sec). Finally, CB3 is reclosed by IED2 (after 30.569sec).
Area 4	SS3 to PS	First, CB3 is opened by IED2 (after 146ms). Then, SW6 is opened by IED4 (after 1.817sec). Lastly, CB3 is reclosed by IED2 (after 30.569sec).

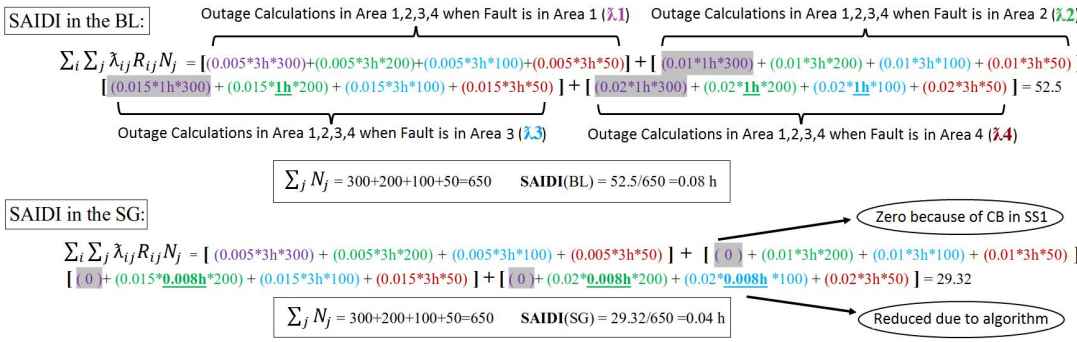
As can be seen in Table II, protection behaves Selectively and distribution network reliability (service availability) is increased. Network reliability can be evaluated by calculating reliability indices such as SAIFI and SAIDI. Logic Selectivity improves both of these indices. In order to analyze effect of Logic Selectivity, reliability indices are calculated for two scenarios: Smart Grid (SG) and Baseline (BL). While our depicted lab setup (Fig.1) is considered as SG scenario, the BL scenario (for Fig.1) is defined when only PS contains CB and all the SSs contains SWs that are operated manually. Also, there is only one IED (without automatic reclosing function) in PS. Reliability indices are calculated as:

$$SAIFI = \frac{\sum_i \sum_j \lambda_{ij} N_j}{\sum_j N_j} \qquad SAIDI = \frac{\sum_i \sum_j \lambda_{ij} R_{ij} N_j}{\sum_j N_j}$$

$\boldsymbol{\lambda_{ij}}$ = fault rate in area i affecting to customers in area j

$\mathbf{R_{ij}}$ = outage duration of fault in area i from customers in area j point of view

$\mathbf{N_j}$ = number of customers in area j



Since the electrical network is not actual and simulated in RTDS, some assumptions should be taken into account: the fault rate (λ) of the network is assumed to be 0.5/100km/year. Fault repair time is 3 hours (3h).

TABLE III. NETWORK INFORMATION ASSUMPTIONS FOR THE MODEL

	Area 1	Area 2	Area 3	Area 4
Length (km)	1 km	2 km	3 km	4 km
Fault Rate (λi)	1*(0.5/100) = 0.005	2*(0.5/100) = 0.01	3*(0.5/100) = 0.015	4*(0.5/100) = 0.02
LVCustomer Number(Nj)	300	200	100	50

Power flow is always in the depicted direction and restoration via backup connection is not considered in the above calculations i.e. CB1 is always open and not used for supply restoration during fault condition. In BL scenario, CB/SW manual operation time is 1h. In SG scenario, CB auto-reclosing time is 30sec (0.008h). Also, in algorithm (regarding to Table I and II), fault isolation by SWs is carried out after fault isolation by CBs and during the reclosing time (0.008 h).

SAIFI values are similarly calculated: SAIFI(BL) is 0.05 and SAIFI(SG) is 0.02. According to calculation, the reliability indices are immensely reduced due to Logic Selectivity. These values can even be further decreased by designing additional logic that applies the backup feeder (CB1) during fault.

B. Results Analysis for Non-Functional Testing

In Fig.2, L2TPv3 manages four Ethernet segments (in substations) into one logical segment in which IEDs become capable of exchanging GOOSE over 4G Internet. In this communication, security and automation real time requirements are key enablers of dependable Logic Selectivity.

1) Information Security and Automation Requirements

If information security measures are not considered, unauthorized IEDs/applications may send forged GOOSE messages to the IEDs. This cause malfunction of CB/SW in the network. Eavesdropping is another vulnerability in which an unauthorized attacker captures GOOSE traffic over the Internet. Moreover, 4G Internet must meet the real time requirements for Logic Selectivity algorithm. Precise performance of algorithm requires exchanging of GOOSE within T1 and T2 that have minimum value of 100ms.

Fig.3 shows time setting of the IEDs for the trip signals in the first stage of the algorithm i.e. fault isolation by CBs. When fault happens both IED1 and IED2 detect fault current, start publishing the GOOSE blocking messages and wait for T1 before issuing trip commands to their respective CBs.

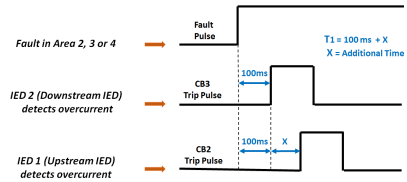


Fig. 3. Time setting of the CB controller IEDs in the lab setup

The protection operates Selectively (IED2 trips to open CB3) only if the value of X be greater than zero in IED1. The X value is determined by the number of GOOSE subscription to each IED. For example, if 50ms is considered for every subscription then the value of the X is 1*50ms (T1=100ms+50ms) in IED1 because IED1 only subscribes to the published GOOSE messages by one IED that is (CB controller) IED2. IED2 is the most downstream CB controller IED in the network and there is no CB controller IED after that. Consequently, no GOOSE subscription has been configured for that and X is equal to zero (0*50ms) that results in minimum T1 value (100ms+0) for IED2 that Selectively issues trip signal before IED1. This concept is same for the SW controller IEDs but they operate based on fault passage (instead of fault detection) with bigger X values because of further numbers of GOOSE subscription in SW controller IEDs.

Security and real time requirements of the Logic Selectivity is analyzed with respect to PICARD [7] model addresses both security (Privacy, Integrity, Confidentiality) and automation (Alarm, Real-Time, auDiting) requirements. In PICARD model, Alarm is hard real time requirement, and Real-Time is cyclic communication real time requirement.

First, trust boundaries are identified: PS, SS1, SS2 and SS3. The most important security requirement is Integrity that ensures GOOSE messages are not altered during transmission. The most important automation requirement is Alarm (GOOSE messages must be received by upstream IED strictly in 100ms i.e. they require hard real time capability) that prioritize GOOSE communication. Lastly, Confidentiality is required to protect GOOSE data from unauthorized access in the Internet.

L2TPv3 over IPsec is proposed to provide communication path with required security between trust domains but cannot in

any way benefit the Alarm requirement. Fig.4 shows PICARD analysis for our use case. Only two IEDs and one-way communication are shown to increase figure clarity.

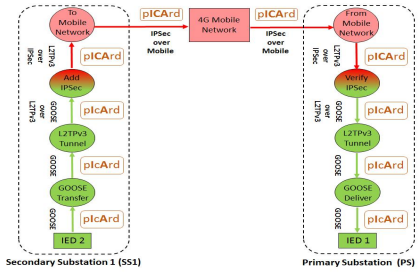


Fig. 4. PICARD analysis for Logic Selectivity

Red elements are untrusted links or processes, green are trusted. Dash lines are trust boundaries. Trust change cannot be made unless there is checks (gradient from red to green) either for communication path, messages or both. IPsec performs communication path security checks verifying untrusted flow (red) conversion to trusted component (green circle).

2) Information Integrity and Confidentiality

We propose that IPsec in Transport mode [12] is used to provide state-of-the-art encryption, confidentiality and authentication. By combining L2TPv3 with IPsec we can mitigate security threats arising from Logic Selectivity operator environment. First 4G modem and Router are authenticated by security credentials during Internet Key Exchange (IKE). Then, a common IPsec security association (security algorithms and policies) is established between them. Finally, Encapsulating Security Payload (ESP) in IPsec provides integrity, confidentiality and authentication for the transmitted data.

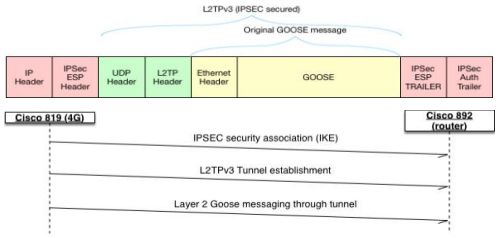


Fig. 5. L2TPv3 frames secured with IPsec

Integrity requirement is also satisfied by L2TPv3 protocols UDP checksumming detecting transmission errors. This complements GOOSE protocols retransmission property where alarm messages are sent repeatedly.

3) Alarm Requirements Analysis

Regarding to Fig. 3, Selectivity relies on the X value that is determined during fault detection by the IEDs. In fault condition, the X value is determined by two factors relating to design and operation phases. Both of these factors must be undertaken for determining the X value. In design phase (IEDs preparation), as it was mentioned in Section IV.A, (CB2 controller) IED1 was configured for GOOSE subscription to (CB3 controller) IED2 that is the most downstream CB controller IED. Therefore, X value is zero in (CB3 controller) IED 2 and higher than zero in IED1. In operation phase (fault detection), the X value in IED1 will be considered higher than zero only if the published GOOSE messages by IED2 are received to IED1 during 100ms waiting time. This depends to the communication network characteristics that must be capable of transferring GOOSE messages during 100ms. If no GOOSE message received during this waiting period, operation in upstream IED1 is not blocked and both IEDs operate simultaneously after 100ms. Thus, GOOSE traffic must be prioritized and transmitted in the high speed Internet.

The Alarm (prioritization) requirement can be achieved via the use of Industrial Ethernet switch in every substation. The industrial Ethernet switch must be GOOSE aware and support Quality of Service for GOOSE messaging.

Current Mobile operators do not support meaningful Quality of Service (QoS) for end users. Therefore, it is necessary to measure communication path characteristics in practice to evaluate feasibility of selected technology for selected use case. In order to analyses the communication network performance of our case, telecommunication measurements are done with SENSOR device that is a dedicated Linux server with 8 Ethernet ports. Network traffic is captured with Wireshark from Cisco 892 and 819 mirror ports.

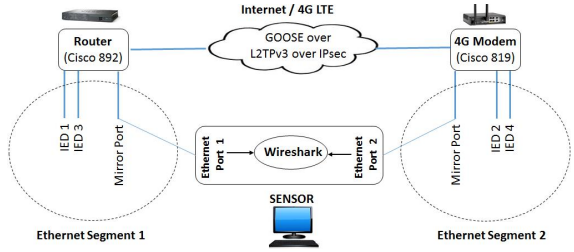


Fig. 6. Communication setup for recording GOOSE traffic over the Internet

Two sets of Wireshark files are recorded for GOOSE traffic: without security (L2TPv3 over IP) and with security (L2TPv3 over IPsec). To analyze bi-directional end-to-end traffic and the quality of asymmetrical data transmissions, the QoSMeT [8] is utilized. This application was developed to monitor QoS parameters affecting end-users' experienced communication quality [8] and M2M latency [18]. The main measured parameters are: jitter, packet loss, delay, connection break duration, offered traffic load and throughput.

QoSmet uses WinPcap's system performance counters. Jitter is the difference of delays between successive packets. Both averaged absolute jitter and moving averaged absolute jitter can be measured. Delay is the most difficult network parameter to measure. The QoSmet application measures the total end-to-end delay at the link level experienced by each packet. As a result, it includes all of the possible delay components e.g. propagation, queuing, and transmission delays. For one-way delay (OWD) measurements, a distributed and highly synchronized clock is required. Commonly used network synchronization method, Network Time Protocol (NTP), is not suitable with the precision of 10ms [18]. For OWD measurement, a separate GPS clock is used in all

measurement points to provide better than 100µs absolute accuracy (using phase information of the GPS signal), which is well enough for the measurements. The latency calculations follow the one-way delay metrics defined in RFC 2679I [19].

In our experiment, we measured jitter and latency over a commercial LTE network using recorded GOOSE traffic from IEDs with a pre-test setup. The goal was to investigate whether the end-to-end delay stays well under 100ms in all cases. Ten recorded measurements were repeated 11 times in order to take the changing network conditions into account. The measured uplink latency and jitter were affected by two factors; additional UDP traffic generated by us to be able to measure with the QoSmet and background traffic generated by the other users in the network. Fig.7 shows a measurement case where our own traffic was enough to keep radio resources allocated. The jitter stays around 7ms and is rather constant. The end of the measurement (after 1176 s) shows the impact of lower background load in a commercial LTE network when people are leaving the office. Average delay and jitter reduce, but the deviation increases. Nevertheless, the values stay well below the threshold of 100ms and jitter is rather constant.

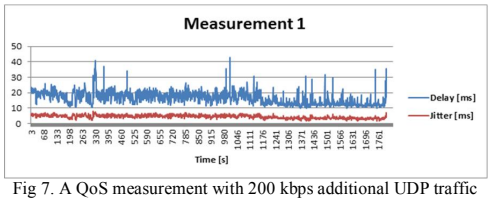


Fig 7. A QoS measurement with 200 kbps additional UDP traffic

The second measurement (Fig.8) shows a case where smaller additional UDP traffic was used. The LTE network starts releasing radio resources, which increases the jitter deviation. Moreover, two short connection breaks were encountered. The effect was that the connection gets abrupt and high peak delays get generated (see 145 s and 298 s in the graph). The maximum peak delay value is around 60ms, which is still well below the 100ms threshold. However, the concern is that the jitter peak increases from 10ms to 90ms, which in specific cases, e.g. data encryption, can result the latency to exceed the 100ms threshold.

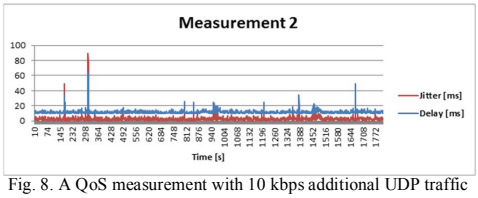


Fig. 8. A QoS measurement with 10 kbps additional UDP traffic

Analyzing Wireshark files with IPsec security is still under process since QoSmet is updating for this type of analysis, and detailed results will be published later. We expect IPsec causes insignificant delay when compared to 4G network delay.

VI. Conclusion

This paper analyzed effect of GOOSE-based Logic Selectivity on service availability enhancement in the distribution network. Also, secure Internet communication was created by encapsulating GOOSE messages in L2TPv3 tunnel and transporting them with IPsec. The paper also represented the pre-test lab results, which indicate that in most scenarios, the latency of GOOSE message is well under the 100ms threshold. However, there exist some peak values that require further analysis and countermeasures.

Logic Selectivity is fully functional and SAIDI value is improved only if the security and real time requirements for GOOSE communication are satisfied. The published GOOSE messages by the downstream IEDs must securely receive to the upstream IEDs during 100ms threshold time in LTE network.

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Security and Reliability Analysis of A Use Case in Smart Grid Substation Automation Systems

Peyman Jafary, Sami Repo
Department of Electrical Engineering
Tampere University of Technology
Tampere, Finland
Peyman.Jafary@tut.fi, Sami.Repo@tut.fi

Jari Seppälä, Hannu Koivisto
Department of Automation Science and Engineering
Tampere University of Technology
Tampere, Finland
Jari.Seppala@tut.fi, Hannu.Koivisto@tut.fi

***Abstract*—Substation automation systems provide high level of automation for both substation and distribution network. Communication in modern substation automation systems is based on Ethernet, TCP/IP and interoperable protocols within standard network infrastructure. Communication security and reliability become important and must be considered to ensure correct operation of substation automation systems. This paper presents an experimental lab setup in which IEC6180 standard is applied for substation communication. Designing substation LAN with Parallel Redundancy Protocol and programming proxy server supporting Transport Layer Security are proposed for reliability and security of the substation data network, respectively. Also, substation remote communication security is evaluated by testing two communication standards (IEC60870-5-104 and OPC UA) and two types of VPN: PPTP and IPsec. Test results are compared and the most secure solution is proposed. Securing remote communication assures reliable operation of the substation in the distribution network.**

Keywords—distribution automation security; IEC61850; Parallel Redundancy Protocol; substation automation security

I. INTRODUCTION

In the distribution network, substation automation is achieved by utilizing automation technologies within substation on both device and substation levels. On device level, Substation Automation Systems (SAS) provide local automation inside the substation. On substation level, SAS participate in distribution automation by exchanging measurements/commands with remote Control Center (CC).

Network is an important component in modern SAS supporting advanced networking and communication standards. Substation data can be accessed locally via the substation LAN or remotely (in the CC) via the Internet-based communication. Substation data can be exchanged in form of standard messages in accordance with IEC61850 [1] that not only contains standard information model [2] but also coordinates with widespread networking standards like TCP/IP. Applying standard messages and open infrastructure provides many benefits such as interoperability but on the other hand risk of security threats [3][4][5] is increased in substation local and remote communication. Considering security measures [6][7] are mandatory to satisfy the requirements for SAS on both device and substation levels. IEC 62351[8] discusses security mechanisms that can be used for SAS.

This paper describes a use case for modern SAS that applies IEC61850 communication. Security and reliability weaknesses of the use case are analyzed and proper solutions are proposed based on the existing facilities in our lab. In the following, Section II describes modern SAS. Next, security in SAS is explained in Section III. Section IV contains use case description. Then, security and reliability for the use case in Section V. Finally, conclusion is presented in Section VI.

II. MODERN SAS

In this paper SAS always refer to the primary substation in the distribution network i.e. substation for transforming High Voltage (HV) level to Medium Voltage (MV) level.

A. Modern Substation Architecture

Smart grid substation contains three [7] logical levels: Process, Bay and Station levels. Process level includes current and voltage transformers that provide measurement data via network interface instead of hard wiring. Intelligent Electronic Devices (IEDs) are placed in Bay level. Station level consists of monitoring and higher level automation devices including substation computer and Station Gateway (SG). Substation connects to the external network (Internet) from Station level.

These substation levels are connected via Industrial Ethernet (IE) switches in which IEDs and automation applications communicate through substation LAN by using IEC61850 standard. The managed IE switch should be applied in substation LAN. The switch should also conform to the IEC 61850-3 and IEEE 1613 standards that guarantee continuous operation of switches in the substation environment.

B. Specific Requirements of Substation LAN

Substation network requires particular devices and standards that meet the requirements of SAS applications. Two functions are very vital in the Ethernet network of substation: time synchronization and network redundancy. Although there are several standards for time synchronization and redundancy in computer networks, but those are not appropriate for substation network. Substation IEDs can use the same network (substation LAN) for exchanging process data as well as time synchronization information by using Network Time Protocol (NTP) or Simple NTP (SNTP). However, these protocols present time accuracy within the millisecond range which could not meet the timing requirements of the extreme time

demanding applications such as Sampled Values (SV) [9] and Synchrophasor applications (IEC61850-90-5 and IEEE C37.118). These applications require extremely high time synchronization accuracy in microsecond range. The IEEE 1588v2 Precision Time Protocol (PTP) [10] should be applied for time synchronization in substation LAN.

Furthermore, a redundant network topology such as ring is required because data availability is critical for IEDs. In computer networks, Spanning Tree Protocol (IEEE 802.1D) and Rapid Spanning Tree Protocol (IEEE 802.1W) are applied for administration of ring topology. However, they are not fast enough for the SAS applications because of their long recovery times that is in the second range. Faster protocols with smaller recovery times are required in substation LAN. IEC 62439 standard defines redundancy Ethernet protocols. The most reliable ones are Parallel Redundancy Protocol (PRP) [11] and High-availability Seamless Redundancy (HSR) [12] that provide zero recovery time.

C. Communication Types in IEC61850-based Substation

Substation communication can be categorized into two groups: Horizontal and Vertical. All IEDs and their relation can be officially described with the aid of the Substation Configuration Language (SCL) as the XML files. SCL files specify sender, receiver and content of the transmitted messages in Horizontal and Vertical communication.

TABLE 1. HORIZONTAL COMMUNICATION VS VERTICAL COMMUNICATION

	Horizontal	Vertical
Scope	Bay level	Bay and Station level
Direction	IED to IED	IEDs and substation computer/ SG
Data Content	protection/interlocking	command/reporting
Messages Type	GOOSE messages [13]	MMS messages [13]
OSI Layer	layer 2	layers 3 and 4
Data Transmission	Ethernet network	Ethernet network
Communication Model	publish-subscribe	client-server
Time Criticality	highly time-critical	lesser time-critical
Information Flow	defined in SCL files	defined in SCL file

III. SECURITY IN SAS

Security for substation data must be designed to mitigate security threats, and protect substation against cyber-attacks.

A. Security Threats in IEC61850-based Substation

Security threats may be originated from either internal network of the substation or external network connection to the substation LAN. In substation LAN, there are potential security threats in all the substation levels. In Process level, unavailability of measurement data (SV) at the right time will result in improper operation of the protection IEDs. Moreover, fabricated SV may be generated in substation LAN by attacker. On Bay level, unauthorized access or cyber-attack to IED may change its critical setting or modify the configured GOOSE messages. This may lead to malfunction of the substation or serious damage to the electrical components. On Station level, plugging the USB stick with a malicious code or opening an infected email by the substation employee may give the remote attacker the computer access privileges of an employee. Furthermore, traffic analysis is another threat in which attacker penetrates the substation LAN and analyze network traffic to retrieve or modify sensitive data.

External data connection to the substation is carried out via SG instead of conventional RTU [7]. Substation SG applies Internet communication for exchanging data with CC. This communication is vulnerable to security threats and may expose substation assets to security attacks. Eavesdropping and message alteration are vulnerabilities in which an unauthorized attacker captures (SCADA) data traffic, modify the transmitted messages or generate spoofed messages. This can cause wrong substation operation and electrical power disruption.

B. Security Measures for IEC61850-based Substation

Data communication must be protected in both substation LAN and substation external communication. The Defence-in-depth [14] security principles should be considered from the planning and design phases of the substation. In Process level, security can be achieved by implementing Virtual LANs (VLANs) and Quality of Service [15] for segmenting and prioritizing time-critical traffic. Bay and Station levels communications (GOOSE and MMS messages) should be secured via IEC62351 standards. Substation LAN must be separated from external network either by Station level firewall or designing Demilitarized Zone. Additionally, Intrusion Detection [5] system can be used to recognize abnormal condition in which intruder tries to access substation IEDs.

In substation remote communication, secure version of SCADA communication protocols must be applied between substation and CC. For instance, OPC UA along its security model [7] or DNP3 with security enhancement [16]. VPN tunnel must be used for SCADA protocols without built-in security function, for example IEC 60870-5-104 (IEC 104).

IV. USE CASE DESCRIPTION

The aim of this Section is to build an experimental lab installation to model an IEC61850-compliant substation. In this Section, the lab setup is built without considering security. Communication security will be discussed in next Section.

A. Lab Setup Description

A substation including a transformer (110/20 KV), busbar, and one MV feeder are simulated in the Real-Time Digital Simulator (RTDS) [17]. Two protective IEDs, i.e. Feeder Protection Relay (FPR) and Busbar Protection Relay (BPR), are externally connected to RTDS. These IEDs are attached to the simulated feeder and busbar, respectively. Additionally, the SG device is used to exchange data with local IEDs and remote CC application. The SG is an industrial computer with Microsoft Windows operating system. Both SG device (ABB COM600) and IEDs (ABB Relion family) are from ABB.

Moreover, the IEC61850 client application is programmed in Java by using MMS libraries and installed in the substation computer. Another computer is also applied for substation remote monitoring. This computer contains IEC 104 master [18] application that communicate with SG. Fig.1 illustrates devices and applications that are used in the lab setup.

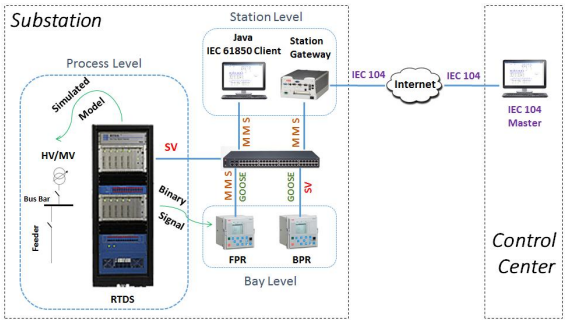

Fig. 1. Lab setup componenets (without security and reliability)

The following features are defined for our experiment:

-RTDS sends measurement data (voltage values) as the Sampled Values (SV) [9] to BPR via IE switch.
-In RTDS, status (open/close) of the feeder circuit breaker is sent to FPR as the binary signal.
-The binary signal is defined in IEC61850 format for FPR that performs Vertical communication and sends this data to SG.
-FPR also carries out Horizontal communication and sends overcurrent blocking signal in form of GOOSE to BPR.
-Substation local monitoring via Java IEC61850 client that performs Vertical communication by requesting status of the feeder circuit breaker from FPR via MMS messages.
-Substation remote monitoring via IEC 104 master that asks feeder circuit breaker status from SG. IEC 104 is selected because of its popularity and TCP/IP communication support.

B. IEC61850 Configuraion of IEDs

IEC61850 data model structure [2] is based on the hierarchical data model that includes Physical Device (PD), Logical Device (LD), Logical Node (LN), Data Object (DO) and Data Attribute (DA). The IEDs configuration software tools are used for defining IEC61850 data format for the Horizontal (FPR.LD0.PHIPTOC.Str.general), Vertical (FPR.CTRL.CBXCBR1.Pos.stVal) and Sampled Values (BPR.LD0.MMXU. PhV.mag) communication.

V. Security And Reliabity For The Use Case

As it was discussed in Section III.A, security threats may appear from either substation LAN or external communication. In Fig.1, there are security weaknesses in all the substation levels. A failure in IE switch or device connections to the switch leads to unavailability of data in the whole or part of the substation LAN. Data integrity can be endangered by modifying setting of the IEDs/SG by unauthorized attacker, generating forged messages by connecting an illegal device to the IE switch, undesirable changing of circuit breaker status from the Java IEC61850 client and spreading malware to substation LAN by connecting malicious USB to the substation computer. Moreover, substation data confidentiality may be lost by penetrating the unauthenticated user to substation LAN.

In Fig.1, there are also potential security threats for the external communication of the substation with the CC. If substation data is sent as the plaintext (IEC 104 messages), the attackers will be able to perform various security attacks such as eavesdropping and message modification. In this situation, the attacker can conceal substation events from CC, modify substation data that is sent to CC, and send forged commands to SG/IEDs by impersonating CC personnel. Thus, security measures must be considered for both substation internal and external communications. In the following, security solutions are proposed by utilizing existing resources in our lab.

A. Security and Reliabilty Solutions for the Substation LAN

Confidentiality, Integrity and Availability are used as the benchmarks for evaluating communication security. In substation LAN, the order of security requirements is first Availability, next Integrity and lastly Confidentiality[14]. The most important requirement is data availability. Substation data (specially SV) should not only be highly available but they should also be delivered on-time to the IEDs for accurate functioning. One way to increase data availability is network redundancy. In our experiment, IEC62439-3 PRP is selected for network redundancy because the main devices (FPR, BPR and SG) support this protocol.

1) High Data Availability in Substation LAN

In Fig. 2, IEC 62439-3 PRP networks are designed to increase data availability for the SAS in the substation LAN.

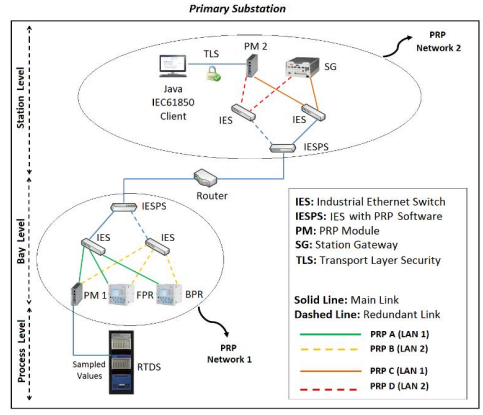

Fig. 2. Security and reliability solutions for substation LAN in the lab setup

IEC 62439-3 PRP [11] is OSI model layer 2 redundancy method which provides zero recovery time. It is based on Ethernet frame duplication that is transparent to higher layer protocols. PRP can be used in any network topology with both PRP and non-PRP nodes. PRP nodes are called Doubly Attached Nodes (DANs) that contain two Ethernet interfaces (A and B) connecting to two separate LANs.

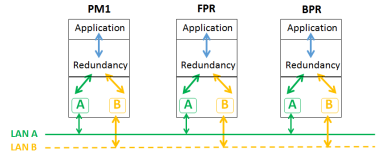

Fig. 3. DANs connection in the PRP network 1 of the lab setup

Non-PRP nodes have only one Ethernet interface and are named Single Attached Nodes (SANs). SANs connect to just one LAN and can exchange data with other SANs in the same LAN. However, SANs can act like DANs via the redundancy box [11] in which SANs also become capable of linking to two separate LANs in the PRP network. In our testing, RTDS and substation computer are considered as the SANs and connect to the PRP networks via redundancy boxes i.e. PRP modules [19] in Fig.2. In the following, PRP network design and operation are briefly explained.

From PRP network design point of view for our use case (Fig.1), first redundancy solution that comes to mind is designing a single PRP network for all the devices in which they should be categorized into different IP subnets based on their communication type and time-criticality. In this case if devices are grouped into different subnets within single PRP network, then a routing function is required for communication between devices. However, PRP is layer 2 redundancy protocol that originally has no support for IP routing because source MAC address field is changed due to routing and this field is used for duplication frame detection at PRP receiver side [20].

Although alternative routing options such as PRP-enabled router or PRP protocol modification algorithms are proposed in [20], however normal router and standard PRP devices are applied in our experiment. Therefore, routing between various subnets is not applicable by designing a single PRP network.

In Fig. 2, two separate PRP networks are designed to increase data availability and network manageability. While PRP network 1 includes PRP network of time-critical devices on Process and Bay levels, PRP network 2 is designed for Station level devices. Data exchange between two PRP networks is achieved by a router that is connected to two PRP networks via Industrial Ethernet Switch with PRP Software (IESPS) [21]. Each IESPS has two parallel Ethernet ports that are attached to the regular IE Switches (IES) in each PRP network.

From PRP protocol operation point of view, every PRP device (or non-PRP device equipped with PRP module) has two Ethernet interfaces but with the same MAC addresses. Data transmission via two Ethernet controllers is managed by the Link Redundancy Entity (LRE) software [11]. In sender device, LRE duplicates the data frame and simultaneously sends two identical data frames to both LANs. In receiver device, LRE receives identical data frames from both LANs and filters the duplicated frame. LRE delivers just one data frame to the upper layer. The designed PRP networks ensure data availability in Process, Bay and Station levels. In case of failure in IES or communication link, data will be automatically available from the backup network.

2) Integrity and Confidentiality in Substation LAN

In the use case (Fig.1), data integrity and confidentiality can be provided by implementing the IEC62351 [8] standards. However, the IEDs in our testing has currently no support for this protocol. Therefore, it is tried to provide security via Java IEC61850 client because of flexibility for adding security functions to the Java source codes of the application. This application asks status of the circuit breaker from FPR via MMS message. The first try is to create Transport Layer Security (TLS) between the Java IEC61850 client and FPR by executing Secure Socket Layer (SSL) protocol. However, SSL is also not supported by FPR. The next attempt is to use the SG as the intermediary between the IEC61850 client and FPR because SG runs Microsoft Windows operating system and this presents more possibilities for implementing security protocols. In Fig.4, proxy server that implements both MMS and TLS are proposed for securing traffic in the substation Station level.

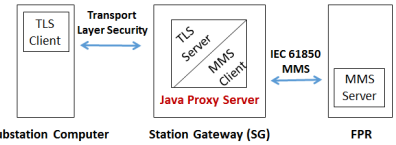

Fig. 4. Proxy server with Transport Layer Security

First, place of the Java MMS client is shifted from the substation computer to the SG. Next, TLS (version 1.2) client and server are programmed. The TLS client is installed in the substation computer. The TLS server and MMS client are combined and programmed as a single Java application that functions as Proxy server. Java is also installed in both substation computer operating system and embedded Microsoft Windows of the SG. Now, substation computer can securely request/receive the circuit breaker status from SG. All the data traffic is secured by SSL.

SSL includes two main groups of protocols: the first group comprises Handshake protocol, Change Cipher Spec protocol and Alert protocol. The second group contains the SSL record protocol [22]. The SSL record protocol provides integrity and confidentiality for the connection between the substation computer and SG by using the shared secret keys that are created during Handshaking in the SSL session. These session keys are applied for creating a Message Authentication Code (MAC) and message encryption. Fig.5 illustrates format of the Ethernet data frames that are transmitted between the substation computer and SG.

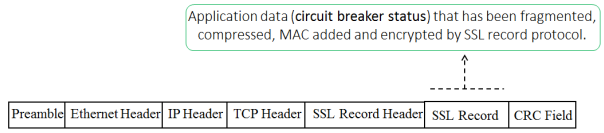

Fig. 5. Secure data transmission in substation Station level

The SSL session keys provide integrity and confidentiality for data transmission between TLS client and server. In order to enhance integrity, TLS client access to the server is also designed to be controlled after creating the SSL session. For this purpose, authentication mechanism for the TLS client is designed while TLS client and proxy server are programmed. Accordingly, client authentication (by the client password) is also required in addition to the server authentication (by the server X.509 security certificate) that is generally happened during the handshaking. As a result, other clients in substation computer or substation LAN are not allowed to access substation data in the proxy server.

Security in Bay and Stations levels are further increased by user authentication for access to IEDs/SG, disabling unused Ethernet and USB ports, and Port security (allow specific MAC addresses connection to the enabled Ethernet ports).

B. Security for the Substation Remote Communication

In substation remote communication, the order of security requirements is first Integrity, next Availability (high-critical for control and less-critical for monitoring) and lastly Confidentiality [23]. In our use case (Fig.1), the IEC 104 master is used to remotely receive the feeder circuit breaker status from SG. The IEC 104 standard has no internal security functions to secure the Internet communication. So, additional security mechanisms must be applied to protect this communication. Alternatively, OPC UA is proposed for securing the remote communication because of its built-in security model [7]. The SG supports OPC Data Access (OPC DA) server but not OPC UA. Therefore, an OPC UA Wrapper [24] is additionally installed in the SG. The wrapper functions as OPC UA server providing substation data to the remote OPC UA client [25] application. Fig.6 shows details of the substation remote communications.

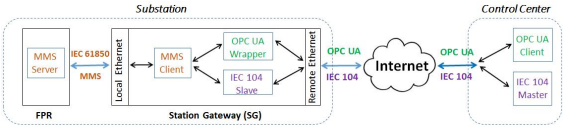

Fig. 6. Substation and control center communication

Generally, substation remote communication can be protected by securing the communication path, transmitted messages or both. While secure communication path can be created by setting up a VPN tunnel, transmitted messages can be secured by applying SCADA communication protocols with internal security mechanisms. In the following, substation remote communication security is evaluated by testing two types of VPN (PPTP and IPsec) and two SCADA communication protocols: IEC 104 and secure OPC UA.

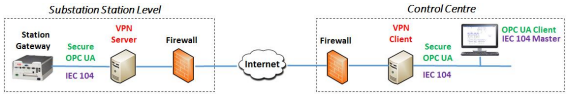

Fig. 7. Secure architecture for testing substation remote communication

First, VPN client/server are configured for PPTP [26] and IPsec [28]. IPsec with Encapsulating Security Payload (ESP) [28] in tunnel mode is employed. Furthermore, substation is protected with firewall that controls incoming network connections to the SG remote Ethernet port. Next, IEC 104 communication and secure OPC UA [7] communication are established. Secure OPC UA communication is configured for: security mode (sign and encrypt), security policy (Basic128Rsa15) and security tier (mutual authentication). Secure OPC UA connection is established during four [7] steps: endpoint discovery, secure channel creation, session creation and session activation.

TABLE II. COMPARISON OF SECURITY IN REMOTE COMMUNICATION

	Security Description
IEC 104	- ***OSI Model*: Application layer** - ***Security Model*: NO** - ***User/App/Device Authentication*: NO** - ***Integrity*: NO** - ***Confidentiality*: NO** - ***Availability:* IEC104 Redundant connections**
Secure OPC UA	- ***OSI Model***: Application layer - ***Security Model***: Secured messages by OPC UA security model - ***User Authentication***: Client validates the wrapper Software Certificate [7] during the Session Creation. Wrapper validates the client Software Certificate during the session activation. Also, username/password that is sent during Session Activation stage from remote CC user to the wrapper. - ***App/Device Authentication***: Mutual [7] authentication: client validates wrapper Application Instance Certificate during endpoint discovery. Also, wrapper validates the client Application Instance Certificate during secure channel creation. - ***Integrity***: Basic128Rsa15 policy: Sign the messages during secure channel creation by the private keys of client and wrapper Application Instance Certificates. Also, sign the messages during session creation and session activation with the derived keys created during secure channel creation. - ***Confidentiality***: Basic128Rsa15 policy: Encrypt the messages during secure channel creation by the public keys of client and wrapper Application Instance Certificate. Moreover, encrypt the messages during session creation and session activation with the derived keys created during secure channel creation. - ***Availability***: Socket connection
PPTP	- ***OSI Model***: Link layer - ***Security Model***: Secure communication path by Layer 2 tunneling - ***User Authentication***: Extensible Authentication Protocol (EAP) [27] for authenticating the VPN client and server. - ***App/Device Authentication***: NO - ***Integrity***: NO - ***Confidentiality***: Data Encryption via 3DS protocol - ***Availability***: NO
IPsec	- ***OSI Model***: Network layer - ***Security Model***: Secure communication path by securing IP packets - ***User Authentication***: NO - ***App/Device Authentication***: Peer authentication via exchanging digital certificates in phase 1 of the Internet Key Exchange [28]. - ***Integrity***: Integrity of IP packets via Hash function of ESP. - ***Confidentiality***: Encryption of IP packets via ESP - ***Availability***: NO

As can be seen in the Table, there is no security functions in IEC 104 standard. So, VPN connection must be used if the IEC 104 is selected for the remote communication. In this case, IPsec is proposed instead of PPTP because IPsec checks data integrity and also has stronger encryption than PPTP. Furthermore, there are security vulnerabilities [29] in Microsoft's implementation of PPTP VPN.

Secure OPC UA is another option for securing substation remote communication. OPC UA contains strong security model creating secured messages for transmission over the Internet. Although OPC UA security model is robust, however applying VPN is also encouraged because of the possible flaws during the OPC UA stack implementation. Maximum security level can be achieved by applying IPsec with secure OPC UA that provide security in the communication path level and message levels, respectively.

As a result, IPsec peers are authenticated by exchanging security credentials in phase 1 of the Internet Key Exchange [28]. After successful peer authentication, IPsec tunnel is

established and OPC UA client in the CC is allowed to create secure OPC UA connection with the OPC UA server (wrapper in the SG). In this step, OPC UA security presents another layer of security in application level for connecting UA client to the UA server. The following messages are transmitted in the substation remote communication over the Internet.

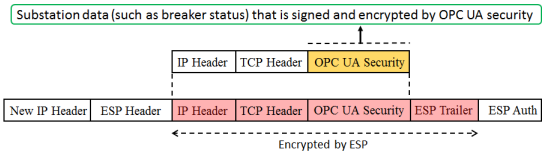

Fig. 8. Secured OPC UA messages within IPsec tunnel

The IP header contains original IP addresses. The New IP header includes IP addresses of the VPN peers. As can be seen, substation remote communication is secured two times: one time with OPC UA security model (in message level) and one time with IPsec ESP (in communication path level). These security mechanisms provide data integrity and confidentiality for remote communication. Moreover, data availability in remote communication can be enhanced by duplicating the communication link between substation and CC in order to maximize Internet availability.

VI. Conclusion

This paper described an experimental lab setup with three goals: modeling a modern substation with three logical levels, applying IEC 61850 data communication in all the levels, and substation local and remote monitoring. Furthermore, reliability and security solutions were proposed for securing Process, Bay and Station levels. In all these levels, PRP networks were designed in order to create highly available automation network with zero recovery time. Data integrity and confidentiality in Station level was assured by programming a proxy server that implements SSL record protocol. Substation remote communication was also secured by IPsec ESP and OPC UA security model. VPN along with message level security are considered as the suitable solution creating end-to-end security for substation and control center data exchange over the Internet. Securing SAS will result in dependable substation operation and consequently efficient distribution network automation.

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Tampereen teknillinen yliopisto
PL 527
33101 Tampere

Tampere University of Technology
P.O.B. 527
FI-33101 Tampere, Finland

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