Faculdade de Engenharia da Universidade do Porto

Emerging Technologies and Future Trends in Substation Automation Systems for the Protection, Monitoring and Control of Electrical Substations

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Resumo

O conceito de subestação inteligente é baseado em tecnologias “state-of-the art” para automação de subestações, e visa permitir uma mais fiável e eficiente proteção, monitorização, controlo, operação e manutenção dos equipamentos e aparelhos instalados nas subestações, bem como responder rapidamente a falhas no sistema e oferecer maior segurança aos operadores. Os Sistemas de Automação de Subestações são responsáveis pela proteção, monitorização e controlo de todo o processo eléctrico de uma subestação eléctrica, e tanto a arquitetura do sistema como a sua estrutura organizacional tornam o sistema fiável, flexível, modular e fácil de expandir. A evolução dos Sistemas de Automação em Subestações teve início na substituição dos relés electromagnéticos por relés numéricos, e prosseguiu com a implementação de comunicações digitais ao nível da subestação, mas ainda sujeitas a protocolos proprietários. Em seguida, o IEC 61850 foi introduzido, e a interoperabilidade entre diferentes dispositivos tornou-se possível, mas o próximo grande passo na evolução da automação de subestações surgirá com a implementação do barramento de processo. O barramento de processo interliga os dispositivos de proteção e controlo ao nível de painel, com os transformadores de medida e equipamento de corte ao nível de processo. Com isso, os fios de cobre convencionais serão substituídos por cabos de fibra óptica, e a transmissão de medidas de corrente e tensão, assim como de sinais de proteção e comando terá lugar sobre uma rede de ligações série, em vez de ligações paralelas ponto a ponto. O barramento de processo torna possível a substituição de transformadores de medida electromagnéticos convencionais por modernos sensores ópticos de corrente/tensão, e a implementação de sistemas de monitorização da condição de ativos. A manutenção preditiva é extremamente importante nos esforços dos operadores para lidar com a redução de pessoal e as exigências crescentes dos clientes para melhor qualidade da energia e fiabilidade no fornecimento de energia. Além disso, os transformadores de potência são os ativos mais caros numa subestação e, portanto, a sua monitorização é essencial para garantir uma manutenção eficiente e a utilização óptima das suas capacidades operacionais. Assim, dispositivos de monitorização on-line para diagnóstico de transformadores, usando a Análise de Gases Dissolvidos para medir o nível de gases combustíveis e humidade no óleo de isolamento, estão a tornar-se cada vez mais populares para avaliar o estado de saúde de um transformador em tempo real.

Abstract

The smart substation concept is built on state of the art automation technologies for substations, and should enable a more reliable and efficient protection, monitoring, control, operation, and maintenance of the equipment and apparatus installed within the substations, as well as rapidly respond to system faults and provide increased operator safety. Substation automation systems are responsible for the protection, monitoring and control of all electric process within an electric substation, and both the system architecture and its organizational structure make the system reliable, flexible, modular and simple to expand. Substation automation systems evolution went from electromagnetic to numerical relays at first, and followed with the implementation of digital communications at station level, but still subjected to proprietary protocols. Then the IEC 61850 was introduced, and interoperability between different devices became possible, but the next big step in the evolution of substation automation will come with the implementation of the process bus. The process bus interconnects the protection and control devices at bay level, with the instrument transformers and switchgear equipment at process level. With it, conventional copper wires will be replaced by fibre optic cables, and the transmission of current and voltage samples, as well as protection and command signals will be over a serial link network, instead of parallel point-to-point connections. The process bus makes it possible to replace conventional electromagnetic instrument transformers by novel optical current/voltage sensors, and to implement assets condition-monitoring systems. Predictive maintenance is extremely important in the efforts of utilities to deal with reduced personnel and increasing customer requirements for improved power quality and reliable power supply. In addition, Power Transformers are the most expensive asset in a substation, and so monitoring is essential to provide efficient maintenance and optimal use of their operational capacities. Therefore, on-line monitoring devices for transformer diagnostics, using the Dissolved Gas Analysis to measure the level of combustible gases and moisture in the insulating oil, are becoming increasingly popular to evaluate a transformers health condition in real-time.

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I would like to thank first and foremost to my parents to whom I owe everything. I am very thankful for their unconditional help and support in every decision I made. They helped shape me into the person I am today. And none of what I achieved in life would have been possible without them, and for that I am forever grateful. I am also very grateful to my advisor, Professor Helder Leite, and to my supervisors, Engineers Mario Lemos and Carlos Peças Lopes, for their guidance and for sharing their knowledge and expertise with me. I am very pleasant for the opportunity, which was given to me, of doing my thesis project at EDP Energias de Portugal, to which I am also thankful. My special thanks to, and in no given order, Antonio Azevedo, Antonio Silva, Duarte Duarte, Fernando Moreira, José Ramos, Pedro Carvalho, and Diogo Oliveira, who passed away, for being with me every single day since I got in at the Faculdade de Engenharia da Universidade do Porto, and for making this journey an easy and pleasant one.

Finally, it would be inappropriate to specify names, since they are so many that I could fail to mention some, but I would like to thank all my friends, friends from my hometown, friends from university, friends I become with when as an exchange student at the Royal Institute of technology in Stockholm, friends from Portugal Telecom which was the first company I worked for, friends I become with while in London when working for the European Bank for Reconstruction and Development, friends from EDP Energias de Portugal the company where I am doing my thesis project right now, and from all the groups and societies I am member of, for I am much appreciated. I am very grateful indeed, for their support along all this years, for making my day every single day ever since, and for pushing me to take this endeavour of stop working and doing my thesis after almost 5 years out of university.

Thank You All,
Bruno

“A journey of a thousand miles
begins with a single step.”

Lao Tzu

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Acronyms & Symbols

List of acronyms

AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
AVR	Automatic Voltage Regulator
CCTV	Closed-Circuit Television
CCU	Central Control Unit
CIT	Conventional Instrument Transformers
CMD	Condition Monitoring and Diagnosis
CT	Current Transformer
D	Energy Discharges
DCB	Disconnecting Circuit Breaker
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DNO	Distribution Network Operator
DSO	Distribution System Operator
FAT	Factory Acceptance Test
FOVT	Fibre Optical Voltage Transformer
GC	Gas Chromatography
GOOSE	Generic Object Oriented Substation Events
GPS	Global Positioning System
GSSE	Generic Substation State Events
HAN	Home Area Network
HMI	Human-Machine Interface
HSR	High-availability Seamless Redundancy
HV	High Voltage
HVAC	Heating, Ventilation, and Air Conditioning
ICCP	Inter-Control Centre Communication Protocol
IED	Intelligent Electronic Devices

IP	Internet Protocol
IRR	Internal Rate of Return
ISO	International Organization for Standardization
LAN	Local Area Network
LN	Logical Node
LOS	Line-Of-Site
LV	Low Voltage
MG	Micro Grids
MMS	Manufacturing Message Specification
MOCT	Magneto-Optic Current Transformer
MTBF	Mean Time Between Fails
MU	Merging Unit
MV	Medium Voltage
NCIT	Non-Conventional Instrument Transformers
NER	Neutral Earth Resistor
NLOS	Non-Line-Of-Site
NOC	Network Operations Centre
NPV	Net Present Value (NPV)
MOCT	Magneto-Optic Current Transformer
OSI	Open Systems Interconnection
PAS	Photo Acoustic Spectroscopy
PD	Partial Discharges
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
PRP	Parallel Redundancy Protocol
RBE	Return by Exception
RTU	Remote Terminal Units
SAS	Substation Automation Systems
SAT	Site Acceptance Test
SCADA	Supervisory Control And Data Acquisition
SCL	Substation Configuration Language
SV	Sampled Values
SVC	Static Var Compensator
T	Thermal Faults
TASE	Tele-control Application Service Element
TCP	Transmission Control Protocol
TDCG	Total Dissolved Combustible Gases
UFLS	Underfrequency Load-shedding and Restoration
UVLS	Undervoltage Load-shedding and Restoration
VAR	Volt-Ampere Reactive

VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
WSN	Wireless Sensor Networks
XML	eXtensible Markup Language

List of symbols

α	Transformer Shape Parameter
ß	Mean Time Between Fails

Chapter 1

Introduction

The first chapter, Introduction, guides the reader through all the main topics covered on this report, providing an overview of each of the remaining chapters of the report. It also includes the Thesis Proposal with the problem definition, research approach, and expected results.

Chapter two, Smart Substations, is intended to present the reader with a broad range of concepts about substation automation systems. It reviews some well-established technologies presently available for electrical substations, and introduces some upcoming trends in the power and energy industry.

The third chapter, Substation Automation Systems, covers the Protection, Monitoring and Control systems presently implemented in the standard substations of the Portuguese distribution network operator.

In the fourth chapter, Process Bus Implementation, we shall see what the process bus is, and why its implementation is so critical for the evolution process of electrical substations and substation automation systems.

This chapter, Assets Condition Monitoring, provides an overview of techniques commonly available for transformer asset management. It starts by presenting the reader with the benefits of switching from Schedule Maintenance to Predictive Maintenance, and showing the role of Intelligent Electronic Devices in the Condition Monitoring and Protection of Power Transformers.

The last chapter, Conclusions, makes a summary of all the main topics covered along this report, and provides guidance on future work for those willing to pursue with this project.

Thesis Proposal

The work carried out comes as an extension of the research done by Hélder Leite, Mário Lemos and André Morais in “A Survey of Protection, Automation and Control Systems in the Portuguese Distribution Substations”, [02] and is intended to go further into the novel technologies and future trends of substation automation systems.

Background

Substations are a crucial element in the transmission and distribution of electrical energy, with a primary role of transfer and transform electrical energy by stepping-up or down the voltage. To do this, high voltage switching equipment and power transformers are used, in addition to instrument transformers, which supply the status of the primary system to the secondary equipment. Substation Automation Systems are then used to control, protect and monitor the substations.

Problem

Since the majority of the substations were built in Portugal, more than 30 years ago, there has been a tremendous development of both the primary equipment (switchgear, power transformers) and the secondary equipment (protection, control and metering). Over the years, advances in electronics, information and communication technology changed the way substations are operated. This provides an opportunity to re-design the way new substations are built and retrofit the ones currently in operation.

Motivation

The motivation behind this work is, to study the existing and fore-coming technologies for the automation of substations, provided that they will enable a more reliable and efficient monitoring, operation, control, protection, and maintenance of the equipment and apparatus installed, as well as provide an increased operator safety and ensure high quality of service. Moreover, the implementation of substation automation should help improve financial performance, customer service, and organisational effectiveness.

Previous work

Previous work has been carried out at the bay level, and as of now the connection between Substation Automation systems is moving away from a rigid parallel copper wiring to serial links architecture. However, at the process level, the connection of the Substation Automation systems with the switchgear and instrument transformers is still left to analogue standards, and contact circuits for switchgear operations. Thus the need and importance of carrying out this research work for the distribution network operator.

1.1 – Problem Definition

Description of the Goals

The work that I am doing consists on the following three main activities. Firstly, evaluate emerging technologies and future trends for the Automation of Substations and the Protection, Monitoring and Control of electric power systems. Secondly, analyse the impact of the IEC 61850 communications standard and the process bus implementation on the Digital Instrumentation and Control of Electrical Substations. Finally, review novel Assets Condition Monitoring solutions and Predictive Maintenance methodologies for the Protection and Diagnosis of power transformers.

The outcome of this work is expected to bring major improvements for distribution network operator across the following three main operational areas: financial performance, customer service, and organisation effectiveness. In fact, time and costs reduction in the substation design, construction, commissioning and maintenance; along with increased quality of service and reduced number of outages; and also guarantied safety, efficiency and increased reliability on the operation of the electric power system; are some of the key benefits intended to achieve with this study.

1.2 – Research Approach

Methods to be Used

The research intended to be carried out will focus primarily on the Substation Automation Systems, but across all of its areas of application namely: Protection, Monitoring, Control, Instrumentation, Command and Supervision. In order to cover a wide and varied range of sources, the research will target academic papers, technical journals, articles from magazines, documents from conferences, as well as reports published by the main suppliers, and leader utilities in the sector. The purpose is to get a broad and deep understanding of the subjects previously referred getting the insights from the academic world, the equipment manufacturers, and the electric companies.

Limitations

With the purpose of managing all the information initially gathered, the literature review will be organised within the following 8 categories: Smart Sensing and Measurement, Communications, Autonomous Control and Adaptive Protection, Data Management and Visualisation, Monitoring and Alarming, Diagnosis and Prognosis, Advanced Interfaces with Distributed Resources, Real-Time Modelling, and Cyber Security. Then, due to the wide range of areas covered, and the need to focus on just a few of them, on a later stage the analysis is going to be narrowed down to just the following 3 topics: Substation Automation Systems, Process Bus Implementation, and Assets Condition Monitoring.

1.3 – Expected Results

Results and Conclusions

The latest step in substation development comes with the introduction of the communications standard IEC 61850 and the implementation of the process bus, together with all trends, methodologies and technologies it brings along. As it can be seen next, the architecture of a standard substation automation system is expected to evolve into a topology like the one shown on the following image.

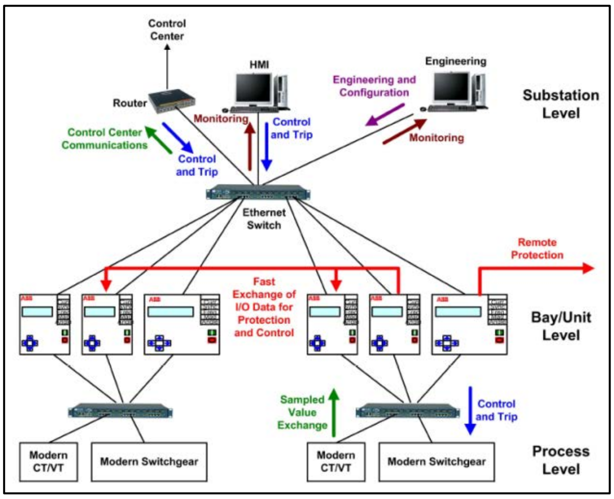

Figure 1.1 - Substation Automation Systems architecture for the Next-Generation Substations.

In a few years, the next generation substations will popup, the station bus is going to connect the IEDs for protection, control and monitoring with the station-level devices, while the process bus is going to connect the bay units with the switchyard devices. Moreover, being based in the IEC 61850 architecture, conventional wiring is going to be eliminated and binary and analogue signals are going to be transmitted and received via the communications interface. Furthermore, both new installations as well as the increasing number of secondary retrofit or extension installations are going to see both sensor and conventional instruments transformers technologies side-by-side. Additionally, setups for the supervision and diagnosis of primary equipment called condition monitoring and diagnosis systems are going to become increasingly popular. With them maintenance methodologies are going to switch from the presently common Preventive and Reactive to a more cost-efficient Predictive approach. Finally, it is also said that, the use of Ethernet network architectures will be extended for the communication within substations and within them and the control centre.

Chapter 2

Smart Substations (Literature Review)

Chapter two, Smart Substations, is intended to present the reader with a broad range of concepts about substation automation systems. It reviews some well established technologies presently available for electrical substations, and introduces some upcoming trends in the power and energy industry.

Initially, given its strategic importance for the electricity networks of the future, and its role as a driver for smart substations to be implemented, particular attention will be given to the Smart Grid, including its characteristics and requirements. Following this, the subject will switch towards Smart Substations, and we will see which technical characteristics and functional requirements the future next-generation substations should respect.

Protections and Control relays are key elements in Substation Automation, and for this reason, we will save a section to cover the evolution in relay designs, from the early electromechanical to the present computer relays, not forgetting the solid-state relays. Afterwards in this chapter it will be discussed the opportunities and challenges of different network architectures and communication technologies. Starting by describing the different communication media available, we will then evaluate the advantages and disadvantages of each network topologies, and finish by addressing two communication protocols for seamless redundancy.

Finally, the last section of this chapter will focus entirely on the IEC 61850 standard. It starts by looking at the two legacy communication protocols it is intended to replace, to move later on into a detailed description of the IEC6180 standard, after which it presents other two communication protocols for use outside substations. At last, we will see some future trends in communications beyond substations, which will only be possible thanks to the aforementioned standard.

2.1 – The Smart Grid

This subchapter is intended to provide an overview on what a Smart Grid is, which is becoming increasingly important given its present within the power and energy industry, and its general relevance for the understanding and study of the next-generation substations.

2.1.1 – Required Functional Areas

The European Union's Smart Grid Coordination Group, in its *"Vision and Strategy for Europe's Electricity Networks of the Future"* report, announces that the current concept of a smart grid should focus on the following eight priority areas [31]:

- Wide-Area Situational Awareness: Monitoring and display of power-system components and performance across interconnections and over large geographic areas in near real time.
- Demand Response and Consumer Energy Efficiency: Mechanisms and incentives for utilities, business, industrial, and residential customers to cut energy use during times of peak demand or when power reliability is at risk.
- Energy Storage: New means of storing energy, directly or indirectly, since the significant bulk energy storage technology available today is pumped hydroelectric storage technology.
- Electric Transportation: Refers, primarily, to enabling large-scale integration of plug-in electric vehicles.
- Cyber Security: Encompasses measures to ensure the confidentiality, integrity, and availability of the electronic information communication systems, and the control systems necessary for the management, operation, and protection of the Smart Grid's energy, information technology, and telecommunications infrastructures.
- Network Communications: A variety of public and private communication networks, both wired and wireless used by the Smart Grid domains and subdomains
- Advanced Metering Infrastructure: It consists of the communications hardware and software and associated system and data management software that creates a two-way network between advanced meters and utility business systems, enabling collection and distribution of information to customers and other parties, such as the competitive retail supplier or the utility itself.
- Distribution Grid Management: Focuses on maximizing performance of feeders, transformers, and other components of networked distribution systems and integrating with transmission systems and customer operations.

2.1.2 – Characteristics and Requirements

Chun-Hao Lo and Nirwan Ansari in [09] provide an overview of the smart grid paradigm and the integration of communications technologies in the legacy power system. In this paper the authors go over different Intelligent automation technologies proposed for smart grid projects as for example Supervisory Control And Data Acquisition / Energy Management Systems (SCADA/EMS), Phasor Management Units (PMU), Automatic Meter Reading / Advanced Meter Infrastructure (AMR/AMI), Field/Neighborhood Area Networks (FAN/NAN) and Home Area Networks (HAN) as well as Demand Response (DR).

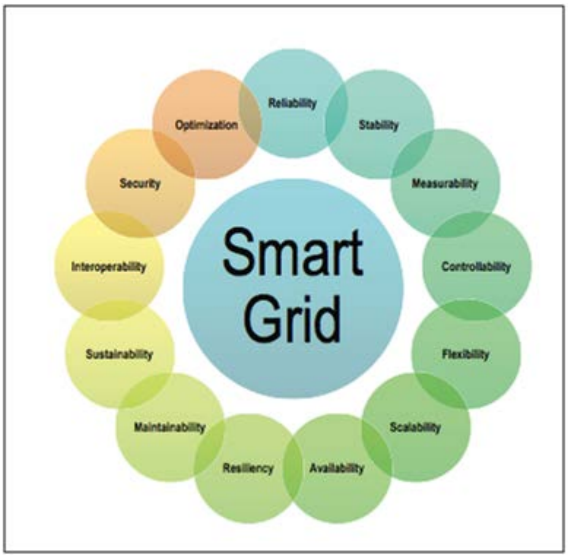

Figure 2.1 - The Smart Grid characteristics and requirements [09].

According to them, the smart grid should include the following characteristics and requirements, which are interconnected in a very close relationship as cause-effect among one another. With these smart features, see Figure 2.1, the smart grid is expected to deal with environmental challenges, market/customer needs, infrastructure challenges, and innovative technologies [03].

- Reliability and Stability – the Smart Grid must guarantee voltage and current stability, mitigate peak demand and load variability with implementation of distributed generation (DG) and energy storage over wide areas, and preclude a variety of incidents.
- Measurability and Controllability – the Smart Grid must be capable of identifying and correcting disruptive operations, i.e. service interruptions and faults that are serious and possible to happen, through dynamic measurements and control monitoring in real time.
- Flexibility and Scalability – as the Smart Grid is moving from a centralised infrastructure to multiple decentralised micro grids (MG), it must provide multiple redundant alternate routes for power and data to flow as well as supply options for feasible control and operation.
- Availability - the availability of power and communications is essential upon consumers' request for energy and information, especially when dealing with latency and security issues, since a latency of few tens of milliseconds should be considered in line protection and control systems.

- Resiliency – the Smart Grid must be capable of restoring and recovering from any failures or destruction caused by natural disasters, deliberate attacks, or malicious activities, through a robust fast-response process, thus ensuring safety and security when incidents happen.
- Maintainability - the Smart Grid must be designed for easy of maintenance, i.e. inspection, troubleshooting and replacement procedures, such that the diverse power and communication components would be repaired rapidly, efficiently and cost-effectively.
- Sustainability - the Smart Grid should provide sufficient greener energy and optimise the system balance and grid assets, in an environmental-friendly and user-friendly manner, in order to deal with the rise of environmental concerns and peak demand risks.
- Interoperability - the Smart Grid should be based on technologies and protocols being interoperable to allow the interconnection of power and communication technologies and in order to offer seamless power and data transport.
- Security - the Smart Grid has to bridge a safe and secure connectivity between suppliers and consumers in order to provide protection for critical applications and data as well as defence against security breaches, while addressing data confidentiality and integrity issues.
- Optimisation - the Smart Grid operation and assets have to be optimised, since it is crucial to reduce the capital cost, network complexity, and resources usage, in order to be practical to develop such a smart grid.
- Mobility – since the positions of the enormous amount of smart meters to be installed worldwide in the forthcoming years will be fixed and static, they should be strategically placed to avoid unwanted location-dependent limitations as much as possible.
- Power Level and Receiver Sensitivity – besides the issues of non-line-of-site (NLOS) signal transmission, the design of power level and receiver sensitivity for the smart meters should as well be appropriately determined.
- Energy Consumption - energy-efficiency in wireless sensor networks (WSN) has always been a top priority and, while most devices are wire-powered in AMI and HAN, more power-efficient schemes are still desired.
- Data Traffic and Prioritisation/Classification - in the Smart Grid, data packets are periodically collected from smart meters, and must be handled and transported either by preceding to its categorisation and prioritisation, or by establishing dedicated channels and routes, but in both ways they need to be time-stamped and classified.

2.2 – The Smart Substation

A traditional substation has four main functionalities: protection, monitoring, control, and metering. Protection involves the detection, isolation and recovery from an electric fault, to ensure human safety and prevent equipment damage. Monitoring involves tracking the state of the equipment installed within the substation and in the network. Control involves the local or remote command of the electric and electronic apparatus. Metering involves measuring analogue signals from instrument transformers and recording digital signals from intelligent electronic devices [30].

2.2.1 – Technical Characteristics

The smart substation concept is built on state-of-the-art automation technologies for substations, and should enable a more reliable and efficient protection, monitoring, control, operation, and maintenance of the equipment and apparatus installed within the substations. A smart substation must as well rapidly respond to system faults and provide increased operator safety.

Fangxing Li et al. defended in [03] that smart substations, together with smart distribution networks and smart control centres, are key elements of the smart grid, and as such shall support the following major characteristics: digitalisation, autonomy, coordination, and self-healing.

- Digitalisation – The smart substation should provide a digital platform for fast and reliable sensing, measurement, communication, protection, control and maintenance of all the equipment and apparatus installed.
- Autonomy – The smart substation must be autonomous, and capable of operate without any interaction with the control centre or other substations. The operation of all equipment and devices, installed within a substation, must also be autonomous to ensure fast and reliable response under emergency conditions.
- Coordination - The smart substation should be able to communicate and coordinate with other substations and control centres in a way to increase the efficiency and stability of power transmission. It should be possible to implement complex protection and control schemes under the coordination of control centres to improve the overall security, reliability, and quality of service of the power grid.
- Self-healing – The smart substation must be able to reconfigure itself dynamically to recover from terrorist attacks, natural disasters, power outages, or equipment failures.

2.2.2 – Functional Requirements

According to [03] in order to achieve the aforementioned characteristics, a smart substation must then include the following major functions: smart sensing and measurement, communication networks and protocols, autonomous control and adaptive protection, data management and visualisation, monitoring and alarming, diagnosis and prognosis, advanced interfaces with distributed resources, and real-time modelling.

Besides these eight specific functional requirements a Smart Substation should also address cyber security. This thus defines the major functional features, technical requirements, and enabling technologies of the next generation substations [30].

Smart Sensing and Measurement

In a smart substation the electromechanical instrument transformers are going to be replaced by optical instrument transformers like the magneto-optic current transformer (MOCT) and the fibre optical voltage transformer (FOVT). These novel sensors have several advantages over conventional transformers, e.g. wide bandwidth, high accuracy of measurement, low maintenance costs, and operation safety.

The replacement of legacy analogue transformers by novel digital sensors will also lead to the introduction of merging units (MU). These electronic devices will be used to merge three phases input signals into a single output signal. In addition, all measurement signals will be digitally sampled and then time stamped with high accuracy by using a global positioning system (GPS) signal [03].

Communication Networks and Protocols

A smart substation has a high-speed local area network to link all protection and control devices and high system applications together. Each smart substation must also have an engineering station, a Human Machine Interface (HMI), and a server that connects to the control centre via a router. This communication architecture should have a certain level of redundancy in order to ensure the reliability and availability of monitoring, protection and control of the substation.

The communication protocol of a smart substation should be standardized and open to significantly improve the interoperability of communication networks. When it comes to Substation Automation Systems (SAS) the future trend is toward the general adoption of the IEC 61860 standard. This standard provides an open interface for communication not only among the Intelligent Electronic Devices (IEDs), but also between substations and control centres, and even between substations themselves.

Autonomous Control and Adaptive Protection

A smart substation should contain a Distributed Control System (DCS) to coordinate with all the Intelligent Electronic Devices (IEDs) in order to improve the reliability and security of the power distribution [15]. Electronic devices as the phase measurement units (PMU) will provide access to both the magnitude and the phase angle of current and voltage measurements, thus making it possible to analyse the state of the electrical power system in real time [03] and [13]. Static VAR Compensators (SVC) can be used as a reactive power supply, either consuming the spare inductive reactive power from the grid or supplying capacitive reactive power to the grid, in order to compensate the reactive power [19]. The next-generation smart substations must then incorporate and coordinate all these devices and technologies.

Data Management and Visualization

In a smart substation, the decentralised supervision and control applications will have access to a distributed database management system where all the power system data is recorded and managed. Each substation should then be able to communicate through an advanced communication network with the other substations and with the control centre providing this way a real-time picture of the power system status. All the data from the protection and control relays, fault recorders, PMU units and smart meters should be efficiently managed, shared and displayed [03].

Monitoring and Alarming

The future substation should provide alarm warnings to authorised users via handheld mobile devices and intranet corporate applications in order to improve awareness. Furthermore, it should be developed an advanced monitoring and alarm system to detect equipment faults, and diagnose system failures in a substation, and immediately inform a number of selected remote operators. The issues comes from the fact that common devices alarm a fault condition locally, and since most of the substations are unmanned, faults may go undetected for extended periods giving rise to more catastrophic failures [03]. These legacy devices should be replaced by modern sensors with communication capabilities and able to provide continuous-time signals such as voltages, currents, temperatures and pressures, instead of just alarm conditions.

Diagnosis and Prognosis

A smart substation should rely on available technologies such as assets condition monitoring solutions and predictive maintenance methodologies to achieve fast diagnosis and prognosis. While online assets condition monitoring based on advanced sensor technology ensures stable operation and prevents catastrophic failures, predictive maintenance allows utilities to deal with reduced personnel and increasing customer requirements.

Advanced Interfaces with Distributed Resources

Smart Substations should provide advanced power electronics and control interfaces for the integration of renewable energy and demand response resources. Smart substations should be able to seamless transition and operate in islanding mode [11], and should as well incorporate micro grids [10], so that after a major commercial outage the power supply degrades gracefully as opposed to a catastrophic loss of power.

Real-Time Modelling

A real-time model of substations should be built for better control inside and outside a smart substation. In order to produce a reliable and consistent real-time model for a substation, a topology processor will build the substation topology, while a state estimator will estimate the substation states, thus providing a more reliable and full view of the substation. A power-systems-wide model can be easily built in the control centre by merging the substation models to significantly improve the operating resilience of control centres against physical and cyber attacks or natural disasters [03].

Cyber Security

A Smart Substation must address cyber security both on a system and on a product level. On a system level the substation automation systems must respect the following key requirements in order to prove secure: Availability (avoid denial of service), Integrity (avoid unauthorized modification), Confidentiality (avoid disclosure), Authentication (avoid spoofing/forgery), Authorization (avoid unauthorized usage and Auditability (avoid hiding of attacks).

On a product level it must integrate robust bay level devices supporting the following security features: individual user accounts; role based access control; enforced password policies; session management; detailed audit trails; secure remote management connection; built-in firewall; built-in VPN capabilities; support for antivirus solutions; and disabled unused ports and services.

2.3 – Intelligent Electronic Devices

Intelligent Electronic Devices are a core element in Substation Automation Systems given its role in the protection, monitoring and control of electrical substations. For this reason, it is important to understand its evolutionary history, which will be presented hereafter in this subchapter.

2.3.1 – Electromechanical Relays

The early relays were designed to use mechanical forces produced as result of the electromagnetic interaction between currents and fluxes such as in a motor [35]. These actuating forces were created by a combination of input signals, stored energy in springs, and dashpots. The plunger relays and the induction relays are examples of these electromechanical protection devices. The plunger type relays are usually triggered by a single input while an induction type relay may be triggered by either single or multiple inputs. Electromechanical relays were, until recently, the primary source of protection mainly because the high cost and complexity of their replacement. However, in new installations, and at major system and station upgrades, the electromechanical relays have been replaced by solid state or digital relays. The following image, Figure 2.2, shows an electromechanical relay based on the induction principle.

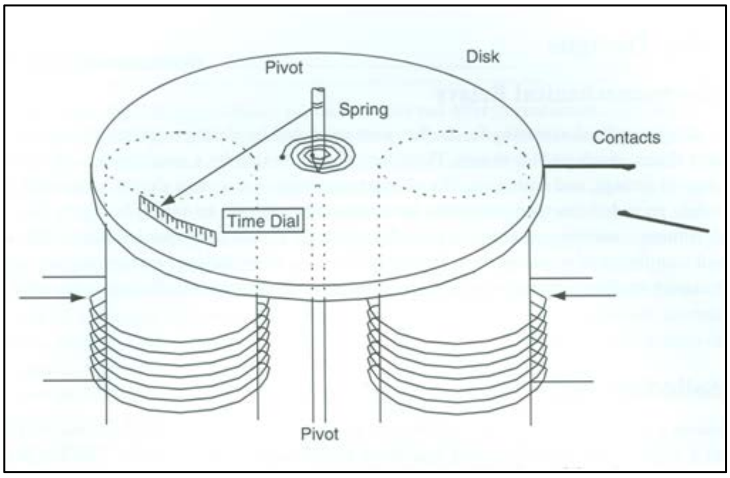

Figure 2.2 - Principle of construction of an induction disk relay [35].

2.3.2 – Solid-State Relays

The expansion and growing complexity of modern power systems have brought a need for protective relays with a higher level of performance and more sophisticated characteristics [35]. The introduction of these new relay designs, generally referred to as solid-state or static relays, has only been possible with the development of semiconductors and other associated components. The solid-state relays perform all the same functions and characteristics previously available with the electromechanical relays. While they are more power-efficient than previous type relays since they use low-power components they also have a lower tolerance to temperature, humidity, overvoltage, and overcurrent. Their characteristics can be adjusted as opposed to the fixed characteristics of electromechanical relays, and their settings are also more repeatable and precise making it a clear advantage in hard-tuning situations. Solid-state relays, as the one shown in Figure 2.3, are designed, assembled and tested as standard equipment, and thus is the manufacturer the one who bears the overall responsibility for its proper operation [35].

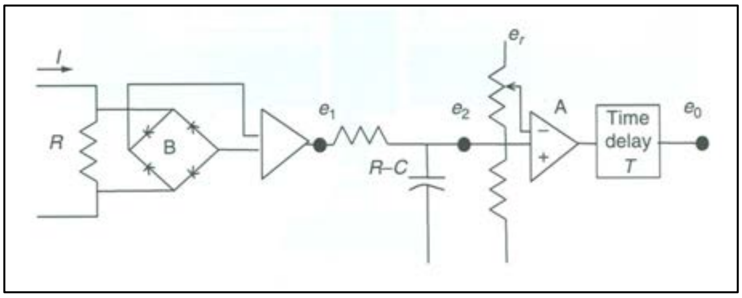

Figure 2.3 - A possible circuit configuration for a solid-state instantaneous overcurrent relay [35].

2.3.3 – Computer Relays

A relay is a device that accepts inputs, processes them electromechanically or electronically to develop a torque or a logic output and makes a decision resulting in a contact closure or output signal [35]. It was no surprise then, that with the advent of rugged, high-performance microprocessors, digital computers started to perform protection functions traditionally performed by electromechanical or solid-state relays. However, since inputs are usually power system voltages and currents, it is necessary to sample the analogue signals, in order to obtain a suitable digital representation of these parameters

Computer relays were initially designed to replace existing protection functions such as transmission line and transformer or bus protection. However, digital relays presented a major advantage over the previous types, its ability to diagnose itself, a capacity only available, if at all, with great effort, cost, and complexity. In addition, digital relays are provided with communication capability that allows for remote monitoring, troubleshooting diagnosis and engineering operations. Finally, another important feature brought by this type of relays is its ability to self-adapt in real-time to variable system conditions. This adaptive feature is rapidly becoming a vital aspect of future system reliability [35].

2.4 – Communication Networks

Substations can be logically divided into three functional levels, i.e. station level, process level and bus level, and two communication buses, i.e. station bus and process bus. The local communication networks for substations have demanding requirements, e.g. capacity, performance, coverage, security, reliability, accuracy, and availability that must be respected [07].

Besides that, a highly reliable, scalable, secure, robust and cost-effective communication network between substations and a remote control centre must also exist in order to enable remote supervision and control [32].

Recent developments in communication technologies have brought along new communication media for last mile connectivity for electric utilities including: power line communication, satellite communication, optical fibre communication, and wireless communication [06].

Another key point with communication networks is the choice of the topology for the Local Area Network (LAN), since each one has its own advantages and disadvantages that must be evaluated to determine the best communication infrastructure. Common network topologies include the Bus topology, Ring topology and Star topology, in addition to hybrid topologies, e.g. Cascaded-Star and Star-Ring [08].

The desired communication network for tomorrow's substation automation systems should also rely on the Ethernet communication protocol to provide an efficient way of remotely monitoring and control of the electric system.

2.4.1 – Communication Media

Mahmood Qureshi et al. in [07] analyse the current state-of the-art communication technologies for substation automation evaluating whether they address critical requirements as capacity, performance, coverage, security, reliability, accuracy, and availability. Cagri Güngör and Frank Lambert in [06] also discuss the opportunities and challenges of different network architectures and communication technologies for electric power system automation applications. In both papers, the authors describe in detail power line, satellite, wireless, and optical fibre communication technologies evaluating both their advantages and disadvantages.

- Power Line Communication consists on the transmission of data and electricity simultaneously over existing power lines, thus offering a broad coverage in a cost effective manner, but is prone to noise, capacity, signal distortion and security.
- Satellite Communication is a viable mean for remote control and monitoring of substations thereby providing global geographic coverage and rapid installation but suffers from unavoidable delays and thus it has performance issues.
- Optical Fibre Communication offers significant advantages over traditional copper-cable communication systems, being technically attractive due to its high data rates and immunity characteristics for Electro Magnetic Interference (EMI) and Radio Frequency Interference (RFI). In addition, the expensive cost of optical fibre is overcomes by the high performance and high reliability that it offers.
- Wireless Communication technologies have several benefits over conventional wired communication networks in order to remotely control and monitor substations. This includes its rapid deployment and cost effective solution, but on the other hand it presents capacity, security and coverage issues.

The benefits and applications of wireless sensor networks for substation automation, and the concept of hybrid network architectures using WiMAX and wireless mesh networks are also introduced and explained in [06] and [07].

2.4.2 – Network Topology

The performance of a substation automation system depends on the implementation of an effective communication system to connect all the protection, monitoring and control devices within the substation. There are three basic communication network topologies, i.e. bus, ring, and star that are commonly implemented with Ethernet switches in electric substations. In addition, there are some hybrid topologies built from the combination of the basic topologies to mitigate their disadvantages and offer better cost performance trade-off [08] and [33].

Star topology

In a typical star architecture, as shown in Figure 2.4, all switches are linked to a common central node referred to as the 'backbone' switch resulting in a star configuration for the Ethernet network. This configuration offers the lowest latency of all topologies and a time delay for the message transmission compliable with the IEC 61850 standard requirements. However, reliability is an issue since there is no redundancy and all devices are connected to a single central switch, the backbone, which is highly susceptible to the harsh environmental and electromagnetic conditions typical of electric substations.

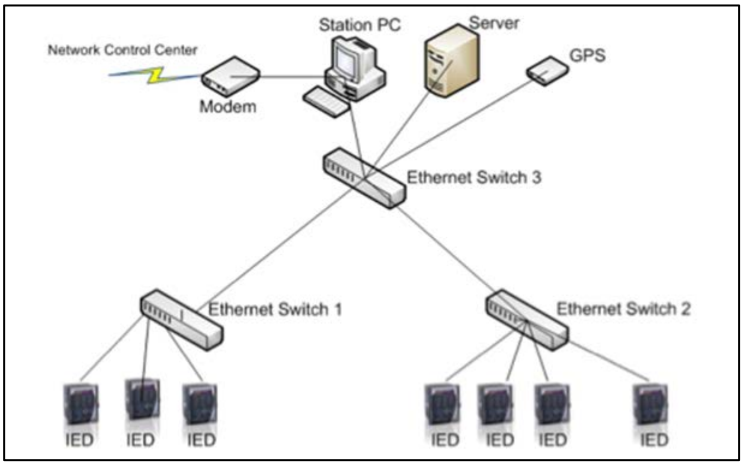

Figure 2.4 - Star Network Architecture [08].

Cascading/Bus topology

A cascading (bus) architecture, as shown in Figure 2.5, has each switch connected to the previous and/or next switch in the cascade via one of its ports. These ports operate at a higher speed than the ports connected to the other devices, but there is also a retransmission delay caused by the internal processing time of each switch, the switch latency. For this reason, the maximum number of switches that can be cascaded depends on the worst-case delay that can be tolerated by the system. This network architecture may provide acceptable time delays in a cost effective manner, but complete reliability is still not achieved since this topology offers no redundancy.

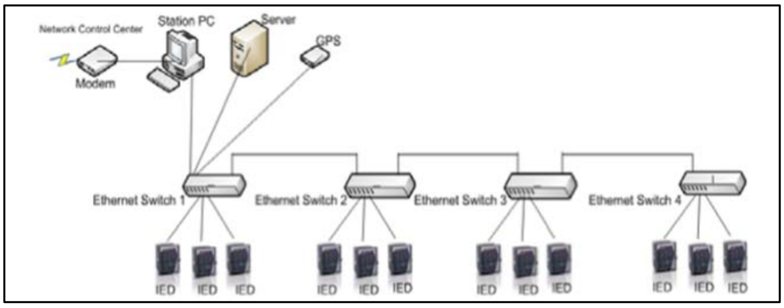

Figure 2.5 - Cascading (Bus) Network Architecture [08].

Ring topology

The ring architecture is very similar to the cascading/bus architecture except that the loop is closed from last switch to first switch, as seen in Figure 2.6, thus providing some level of redundancy if any of the ring connections should fail. However, managed switches must be used in order to prevent messages from circulating indefinitely in a loop, which would eventually eat up all of the available bandwidth. For that, managed switches implement an algorithm called the Rapid Spanning Tree Protocol (RSTP), which allows them to detect loops and logically break the ring. As a result, a ring topology with managed switches allows sub-second network reconfiguration during a communication fault, thus offering physical redundancy. This network architecture provides allowable time delays and offers the better reliability of the three topologies at the cost of being more expensive and complex than the remaining configurations.

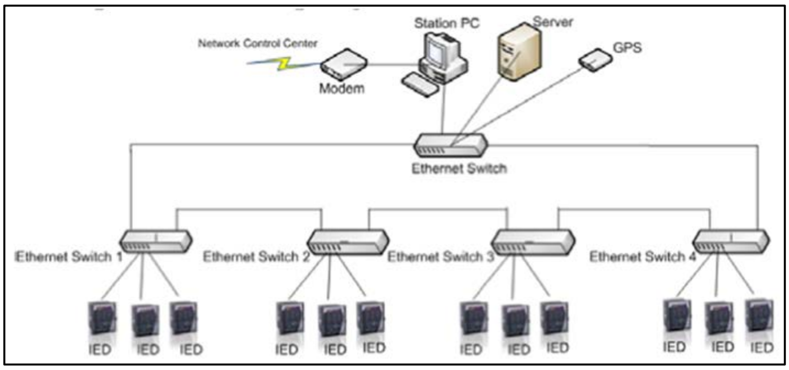

Figure 2.6 - Ring Network Architecture [08].

2.4.3 – Communication Protocols

The IEC 62439 standard, released in February 2010, specifies two redundancy protocols that meet the requirements for reliable industrial communication networks: the Parallel Redundancy Protocol (PRP), and the High-availability Seamless Redundancy (HSR). These protocols provide active redundancy and therefore avoid any reconfiguration delay when a fault occurs in any of the network equipment, as in the case of a switch or link failure. The

PRP and the HSR are also based on the same active redundancy principle, in which the information exchanged is duplicated, but both address different network topologies [34]. Since these protocols provide seamless redundancy, which is crucial in substation automation, they are especially of interest for protection applications based on digital communication such as the IEC 61850.

- Parallel Redundancy Protocol (PRP)

  The Parallel Redundancy Protocol implements redundancy at the device level through doubly attached nodes. Each node is connected to two independent local area networks (LAN) of similar topology that operate in parallel. A source node sends the same frame over both networks, and the destination node receives each frame from both networks, consuming the first received and discarding the duplicated one. The two LANs must be identical in protocol but can differ in terms of performance and topology as well as transmission delays [34].

- High-availability Seamless Redundancy (HSR)

  The High-available Seamless Redundancy protocol is based on the same principles of operation, and also has a zero recovery time in case of a network element failure, but is only applicable to ring topologies. Similarly to PRP, the sender nodes transmit duplicated messages on each direction of the ring, and the receiver nodes interrupt the circulation of both frames. However, unlike PRP, it requires each node on the ring to be HSR capable and non-HSR traffic is not allowed on the ring [34].

It is possible to couple a HSR network to a PRP network through the use of one Redbox for each LAN, as seen in Figure 2.7. These devices must then be configured to allow PRP traffic on the interlink, and HSR traffic on the ring ports. Since both boxes are transmitting frames over the HSR ring as well as the PRP interlink, there will be four identical frames travelling on the ring, and thus frame cancellation must take place at both the destination nodes and the boxes themselves.

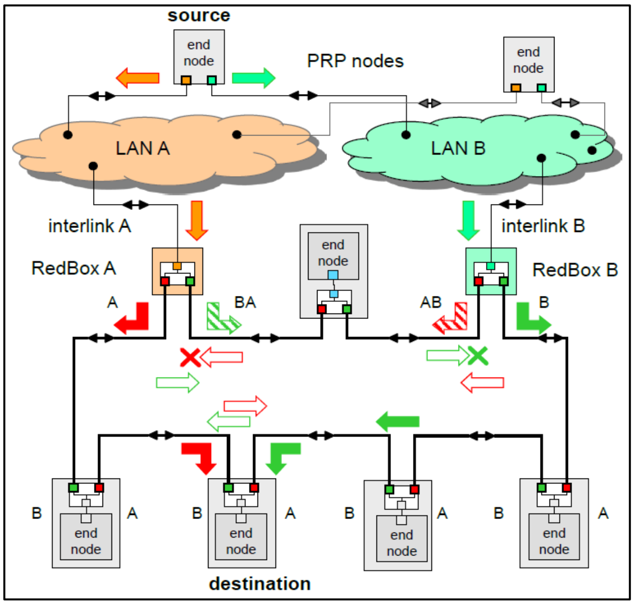

Figure 2.7 - Example of PRP and HSR networks coupled through Redboxes [34].

Within a new generation substation, it is advised to use the PRP protocol for the Station Bus and the HSR protocol for the Process Bus. The station bus is the communication network used to communicate between the protection and control devices as well as between them and high-level systems. In this case, an architecture where all the devices in the system are connected to two independent and redundant networks can handle failure of any communication equipment without any communication interruption [34].

The process bus is the communication network used to connect the protection and control devices with field devices. These applications consist mainly of sampled values and are the most sensitive from a communication point of view because an interruption would generally mean lost samples which would then lead to a protection failure. As for the process level, an architecture where a HSR ring is used to connect the protection and control devices to the merging units that acquire data from the primary equipment, assures redundancy for the sampled values [34].

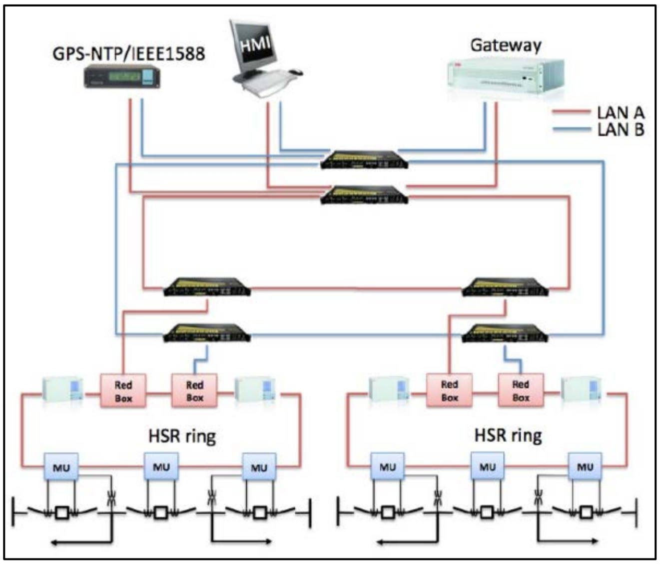

Figure 2.8 - Interconnection of a PRP network with a HSR network [34].

Finally, one must pay special attention when connecting the Process and Station buses since the sampled values are not allowed to travel from the process bus to the station bus. One way to handle the redundant packages is by using multicast filters such as redboxes in between the two buses. In the Figure 2.8, it can be seen an example of an interconnection of a PRP network with a HSR network.

2.5 – The IEC 61850 Standard

Communication protocols and standards were introduced in 1970's, being quickly adopted by the power industry to implement efficient control and automation systems, progressively replacing its proprietary counterparts [04]. Their main objective was to ensure open access, interoperability, flexibility, upgradability and future proof, as well as an effective data sharing among applications.

2.5.1 – Legacy Protocols

The Modbus and DNP3 communication standards are two examples of legacy protocols used in power system industry as for example in distribution substations predominantly with the purpose of ensuring coordination and data sharing between the protection and control devices.

The Modbus is a transmission protocol developed by Schneider in 1979 for process control systems. It is an application layer messaging protocol positioned at the level 7 of the OSI model, and used for client/server communication between devices of the same network. The

Modbus messages can be either of query/response or broadcast / no response type but always initiated by the client.

The DNP3 is a telecommunication standard developed by GE in 1993 that defines communication between client stations, RTUs and other IEDs. It is based on the IEC 60870 standard and was originally designed for SCADA applications, and is currently used in the electrical, water infrastructure, oil and gas, security as well as other industries worldwide.

2.5.2 – IEC61850 Standard

Overview

The IEC 61850 is a standard recommended by the International Electrotechnical Commission (IEC) for the design of substation automation systems (SAS) as referred in [36]. The introduction of the standard for communication networks and systems in substations followed the need for more platform-independent and interoperable protocols. The standard was proposed as a future proof and adaptable communication protocol, capable of providing interoperability in a multi-vendor environment and with a highly advanced object modelling structure [04].

Mohagheghi et al. in [04] provides an overview of the current status of communication networks for substations using IEC 61850, and also discuss the possible future trends for extending the scope of the standard and using its capabilities for other applications within the distribution system.

Ralph Mackiewicz in [05] addresses the key features of IEC 61850 as the possibility to use a virtualised model and names for all data, object names being standardised and defined in a power system context, all devices being self-describing and the standard supporting high-level services, and finally the definition of a standardised configuration language.

Tarlochan Sidhu et al. in [08] introduce the IEC 61850 standard and describe its main features (functional hierarchy, OSI-7 layer model, process bus) as well as its major benefits (interoperability, free configuration, simple architecture, and overall cost savings).

- Interoperability: Different vendors are allowed to provide complete integration of bay functions within one or two IEDs.
- Free Configuration: Any possible number of substation protection and control functions can be integrated at bay level IED.
- Simple Architecture: As the plenty of point-to-point copper wires are reduced to just simple communication links, at the same time that functional hierarchy architecture provides better communication performance for time critical applications.
- Overall Cost Saving: The high-speed digital communication at process level allows replacing the traditional electrical wiring using virtual wiring, which could save a lot of time and cost for substation automation system.

Other benefits that a user can take advantage of by implementing the IEC 61850 are the elimination of procurement ambiguity; the lower installation, transducer, commissioning, equipment migration, extension, and integration costs; and finally the possibility to implement new capabilities [05] and [21].

The authors, in [08], discuss as well the major implementation issues and possible solutions related with the IEC 61850 standard. As for the process bus, the main issues identified are the network topology, communications performance, time synchronization, and environmental requirements. The major implementation issues related with the station bus can be traced down to the communications network, coordination with distributed SAS, and both intra-communication and remote control centre communications.

Other operational challenges imposed by the standard implementation and which need to be addressed are architecture, availability, maintainability, data integrity, testing, inter-changeability, data security, and version upgrade requirements. Finally, there are as well some project challenges to overcome such as the cost and complexity, allocation of the substation functions, system expansion, and manpower training. However, is has been proved that, the overall benefits largely overtake the implementation issues.

Substation Automation Topology

The IEC 61850 standard divides substation networks into three levels within or between which all communications take place: the process level, the bay/unit level, and the substation level. The process level includes the input/output devices, intelligent sensors and actuators; the bay/unit level includes all the protection and control devices; and the substation level includes the engineering workstation, the Human Machine Interface (HMI) and the communications equipment. Figure 2.9 presents a network topology based on the IEC61850 standard.

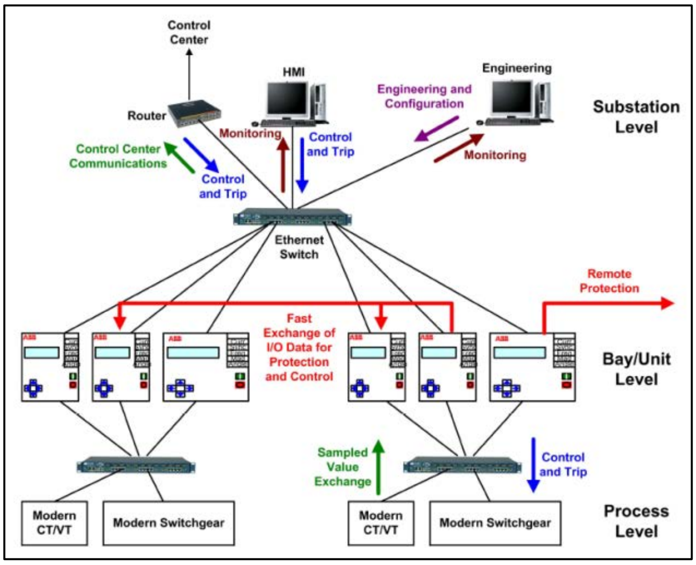

Figure 2.9 - Substation Automation Topology [04].

Data Structure based on Logical Nodes

The IEC 61850 environment is built over an object oriented model where protection and control functions are broken down into smaller units called Logical Nodes (LN) that correspond to various protection, control, metering, and monitoring functions as well as physical components such as instrument transformers and circuit breakers [04] and [14]. Each logical node has data objects within it, each of which contains data attributes. These logical nodes are grouped into logical devices (LD) which are defined in the context of a physical device, with each physical device containing at least one logical device [36], as can be seen in Figure 2.10.

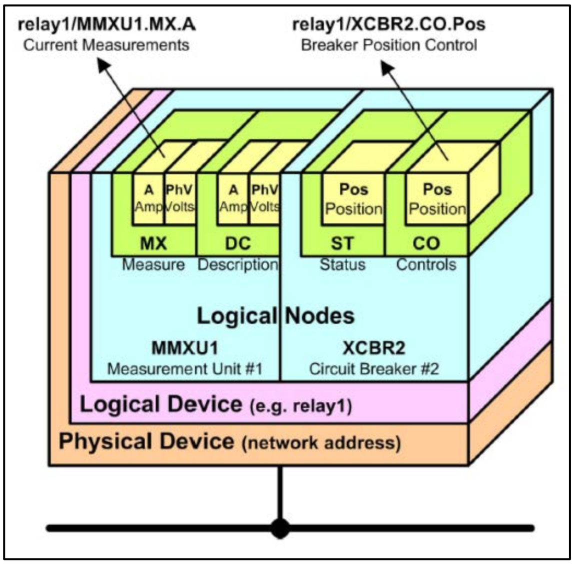

Figure 2.10 - Data Structure based on Logical Nodes [04].

Communication Modes & Communication Services

The IEC 61850 standard introduces, in its 7.2 section, data models and communication services, and defines the syntax and encoding of the MMS messages used for mapping of client/service services to the OSI layered model, as illustrated in Figure 2.11.

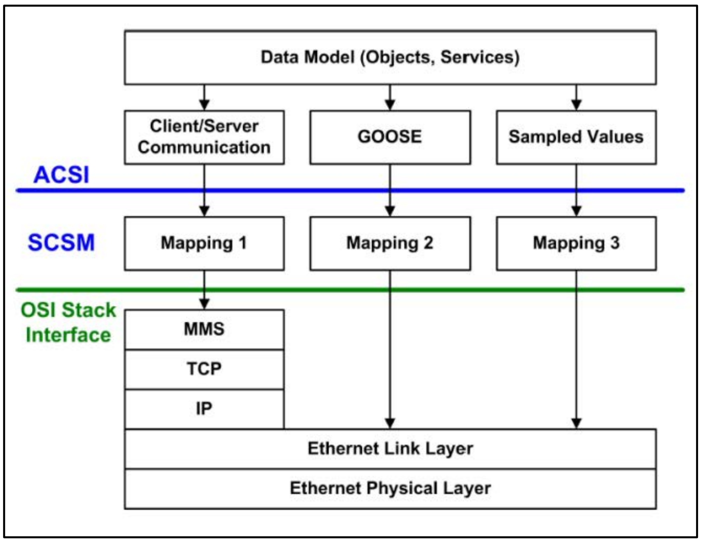

Figure 2.11 - Data Model and Communication Services [04].

The standard provides as well peer-to-peer services for transmitting Sampled Values (SV), between protection and control IED and merging units or actuator IEDs, and GOOSE messages between protection and control IED themselves.

- Sampled Values (SV) are digital signals provided by novel current and voltage sensors used to gather analogue measures from the primary equipment at the switchyard.
- GOOSE messages are used to model high priority status information like trip commands or interlocking information and proceed to its multicast transmission.

Substation Configuration Language

The Substation Configuration Language (SCL) is an eXtensible Markup Language (XML) based language used by IEC 61850 for representation and configuration of the substation automation system (SAS), which enhances the communication capabilities between different IEDs and enables sharing of IED configuration among users [04].

Advantages over Legacy Protocols

Some of the major advantages of IEC 61850 over legacy protocol such as the Modbus and DNP3 are listed below as per [04]:

- Provides close to 100 logical node classes with 2000+ data objects/attributes.
- More easily extendable than legacy protocols.
- Uses hierarchical names instead of indexed addressing.
- Supports quality attribute, time stamp, and cause of transmission (similar to DNP3).
- The data (LNs, data objects and attributes) are more self-descriptive.
- More flexible in parameter setting control allowing the user to define, change and edit the parameters at any time.
- Provides means to transmit substation events (GOOSE/GSSE) and sampled values.
- More flexible in selecting the data for reporting, enabling/disabling the communication control objects, and changing reporting/logging behaviour.
- Complete description of device configuration available in XML
- Fully supports vendor independent engineering tools for development

2.5.3 – Outside Substations

The Inter-Control Centre Communication Protocol (ICCP) also known as Tele-control Application Service Element (TASE) is used by utilities for real-time data exchange communications between control centres. The ICCP is based on the client/server model and works with either an ISO compliant or a TCP/IP transport layer with the following types of requests: single request, request for periodic transfer, and request for Return by Exception (RBE).

2.5.4 – Future Trends

Communications beyond Substations

It has already been proved that the IEC 61850 standard provides an advanced solution for substation automation systems, but it is also generally believed that its automation benefits can be extended beyond substations and its capabilities used for other applications within the distribution system as for feeder automation or communication with control centres.

Extending the IEC 61850 standard to feeder automation applications would ensure the interoperability of all components participating in distribution automation, from the distribution substation to the point of interface with the end users [04]. For this it would be necessary to either use the same logical nodes defined in the standard, or applying the same GOOSE and SV messaging techniques. It could then cover applications such as VAR control, power quality enhancement, information exchange with metering devices (AMI) or control of devices such as network protectors, switches, circuit breakers, fault detectors/locators.

Expanding the IEC 61850 standard to include the connection to the remote control centres would require defining new logical nodes and implementing additional logical connections. This integration could be done either by mapping the IEC 61850 data model content to a traditional SCADA protocol, which may result in loss of some information or speed; or by providing a proxy server to access the IEC 61850 data model content in the substation.

Peer-to-Peer Communications

The IEC 61850 standard can be used for peer-to-peer communications by employing the GOOSE messages concept for applications beyond substations as for example the fast transference of information either between IEDs (e.g. trip commands or outage detection) or PMUs (e.g. over/under-voltage indications or current flows close to stability/thermal limits) at the transmission level [Rerf3.11].

2.6 – Summary

The Smart Grid concept has a key strategic role within the electricity networks of the future and according to the European Union's energy framework it should address the following eight priority areas: wide-area situational awareness, demand response and consumer energy efficiency, energy storage, electric transportation, cyber security, network communications, advanced metering infrastructure, and distribution grid management. The smart grid, in order to deal with environmental challenges, market/customer needs, infrastructure challenges, and innovative technologies, should also meet all the characteristics and requirement described in the Section 3.1.2.

The smart substation concept is built on state of the art automation technologies for substations, and should enable a more reliable and efficient protection, monitoring, control, operation, and maintenance of the equipment and apparatus installed within the substations, as well as rapidly respond to system faults and provide increased operator safety. Smart substations shall then support the following four major characteristics: digitalisation, autonomy, coordination, and self-healing. In order to achieve the aforementioned characteristics, a smart substation must then address all the functional requirements analysed in the Section 3.2.2, plus cyber security.

Electromechanical relays were designed to use mechanical forces produced as result of the electromagnetic interaction between currents and fluxes such as in a motor. These early relays were, until recently, the primary source of protection due to its replacement cost and complexity, but in new installations or at major upgrades they have been replaced by solid-state relays. The development of the solid-state relays, with a higher level of performance and more sophisticated characteristics, was only possible with the introduction of semiconductors. These relays are more power-efficient but have lower tolerance to adverse conditions than electromechanical relays. Their characteristics can be easily tuned and their settings are more repeatable and precise than previous type relays. Computer relays, based on rugged high-performance microprocessors, started to replace existing electromechanical and solid-state relays. These relays generally referred to as intelligent electronic devices, present great advantages over previous designs since they are provided with communication capabilities, and have both the ability to self-diagnose, and to self-adapt in real-time to variable system conditions.

Local area networks for substations have demanding capacity, performance, coverage, security, reliability, accuracy, and availability requirements that must be respected, but in order to enable remote supervision and control, a highly reliable, scalable, secure, robust and cost-effective communication network between substations and a remote control centres must also exist. Recent developments in network architectures and communication technologies for substation automation are also taking place, thus presenting power and energy utilities with a wide range of new opportunities and challenges. The choice between the available communication media for last mile connectivity, i.e. power line, satellite, optical fibre, and wireless, as well as for a given network topologies, i.e. bus, ring or star topology, should be made upon consideration of each other's advantages and disadvantages.

The introduction of the IEC 61850 standard for communication networks and automation systems in electric substations followed the need for a more platform-independent and interoperable protocol. The standard was proposed as a future-proof communication protocol capable of providing interoperability in a multi-vendor environment as well as an effective data sharing among different substation automation applications. The IEC61850 divides substation networks into process, bay, and station levels; and is based on a highly advanced object modelling structure, thus providing interoperability, free configuration, simple architecture, and overall cost savings. This protocol is built over an object oriented model based on logical nodes, and supports advanced communication services by using MMS messages, Sampled Values, GOOSE messages, and the Substation Configuration Language.

Finally, it has been seen that, the desired communication network for the new-generation substation automation systems should rely on novel Ethernet communication protocols as the IEC 61850 to provide an efficient way of remotely monitoring and control the electric system. It is also generally believed that, the automation benefits of the standard can be extended for feeder automation applications and communication with control centres, as well as for peer-to-peer communications between substations.

Chapter 3

Substation Automation Systems

The third chapter, Substation Automation Systems, covers the Protection, Monitoring and Control systems presently implemented in the standard substations of the Portuguese distribution network operator.

The chapter starts with an introduction about distribution substations and their principal elements. This includes a short description of the station yard, the auxiliary equipment, and the operating room. It also gives some details on the panels' definition and line-up within the control house.

The following section starts by giving an overview on the automation systems and their general characteristics. It presents the relay and control cubicles, provides a description for each panel, and addresses the layout of the switchgear. The analysis performed looks at the high voltage and medium voltage levels from a side-by-side view.

Meanwhile, both the architecture and the functionalities of the protection, monitoring, and control systems are deeply analysed. Initially, it goes over the organisational levels and the communication networks. After that, the focus changes to all the protection, control and automation functions performed by the bay units.

Finally, attention is given to the primary applications and support services provided by the substation automation systems, including the control centre, the human machine interface, and the engineering workstation.

3.1 – Standard Substation

Electrical Substations are installations used for the transmission and distribution of electrical energy. Their main purpose is to transfer and transform the electrical energy by stepping-up or stepping-down the voltage. This is done with high voltage switching equipment and power transformers. In addition instrument transformers are used to supply the status of the primary system to the secondary equipment [01].

Distribution Substations' primary role is to step-down the voltage of the electrical energy from High Voltage (HV) to Medium Voltage (MV). A standard installation has two busbars for the high voltage and two busbars for the medium voltage lines, one or two power transformers, switching equipment and instrument transformers, as well as the substation automation systems for protection, monitoring and control.

The HV/MV standard substations of the distribution network are mixed installations, having both outdoor (high voltage cubicles and medium voltage auxiliary equipment) and indoor apparatus (operating room) [37].

3.1.1 – Station Switchyard

It is in the outdoor switchyard where the High Voltage cubicles and Medium Voltage auxiliary equipment are installed. In the switchyard and within these cubicles there are several electric apparatus like the Power Transformer, Voltage Transformer, Current Transformer, Lightning Arrester, Circuit Breaker, Disconnect Switches, High Voltage Line, Busbar Feeders and Insulators.

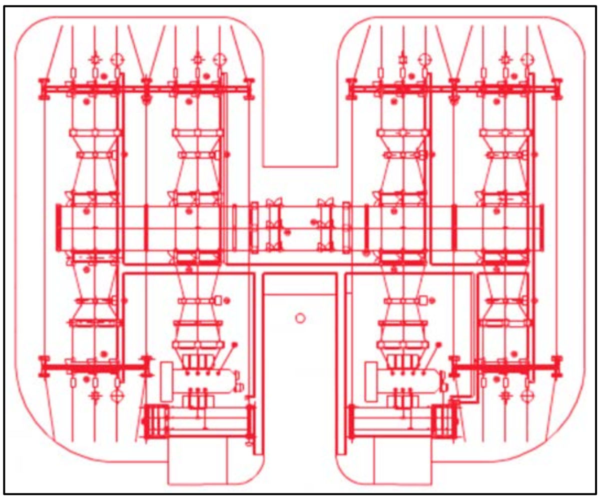

Figure 3.1 - Station Switchyard Blueprint [44].

3.1.2 – Auxiliary Equipment

As seen before, it is in the outdoor switchyard where the High Voltage cubicles and Medium Voltage auxiliary equipment are installed. The Medium Voltage auxiliary equipment that can be seen in a standard HV/MV substation is the Capacitor Banks, the Station Services Transformers and the Neutral Earth Reactors (NERs).

3.1.3 – Operating Room

The Operating Room is a wide space in the control building where it can be found both the Medium Voltage primary equipment, in the medium voltage cubicles, and the protection and control units, in dedicated bay panels. The Substation Automation Systems (SAS), make it possible the supervision and control of the substation, both locally and remotely, and assure the protection, monitoring and control of the electrical processes. The control building has an HVAC (heating, ventilation, and air conditioning) system and specific thermal insulation requirements to guarantee an indoor average temperature between 15ºC and 25ºC. It has also intrusion detection and fire alarm systems, working independently from each other, equipped with microwave and infrared intrusion detectors, and optical fire sensors.

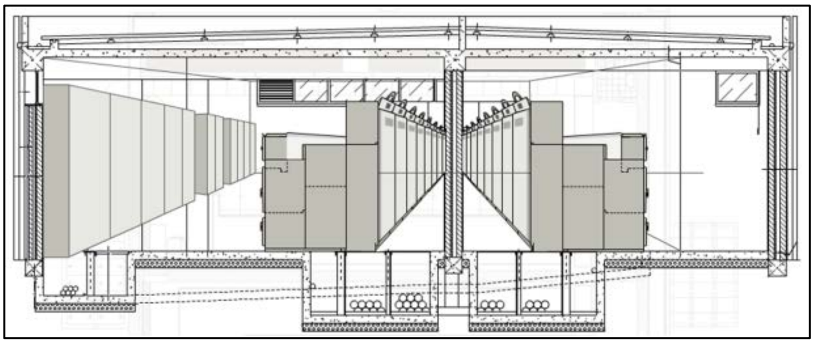

Figure 3.2 - Operating Room Blueprint [37].

3.1.4 – Panels Line-up

- Protection Units: Cubicles where the protection units from all bays are placed. These protection units gather data and measurements (from the Voltage Transformers and Current Transformers) and then evaluate in real time the need to either trig the electrical switches (Circuit Breakers) or change the Power Transformer taps.
- Electricity Metering: Cubicles where the substation electricity metering units are placed. These units measured the real power that flows through the Main Power and the Station Services transformers, as well as the reactive power at the Capacitor Banks.
- Local Control Centre: Cubicles where an industrial PC that acts as a Local Control Station makes it is possible to control all the substation equipment with the aid of a mimic diagram similar to the one at the Remote Control Centre. The human-machine interface

consists of a detailed schematic of the substation, and presents the human-operator with process data as for example the state of switchgear like the circuit breakers, the disconnect switches, and the taps of the Power Transformers.

- Communications: Cubicles where the communications equipment that makes it possible to fully remote control the substation without the need for on-site technical personnel is placed;
- Direct Voltage Station Services: Cubicles where the Low Voltage (LV) circuit breakers that power all the direct voltage substation circuits are. The direct voltage auxiliary batteries power this cubicle, and then each direct voltage circuit in there, powers on the remaining systems such us the intrusion detection and fire alarm systems, the industrial computer, and all the protection and control systems.
- Alternating Voltage Station Services: Cubicles where the Low Voltage (LV) circuit breakers that power all the alternating voltage substation circuits are. The Station Services Transformers power this cubicle, which then powers on several other systems such us, the emergency ventilation, the outdoor cubicles heating, the air conditioning, the lightning lamps and the AC sockets of the substation.
- Voltage Rectifiers: Cubicles where it can be found the equipment used to convert the power supply signal from an AC voltage to a DC voltage, electricity regulator this whom output charges the direct voltage batteries.
- Direct Voltage Batteries: Batteries used to store electric energy and as a backup power supply. Since all protection and control units use a DC signal they can be powered on directly by these batteries. Thus, in the event of an AC supply failure the DC electricity stored in these batteries provides the substation emergency systems with enough power until the AC supply becomes available again. The batteries are of the alkaline type and have 200 Ah of capacity, which is sufficient enough to provide a 20A direct current for as long as 10 hours.
- Medium Voltage Cubicles: Cubicles where the Medium Voltage (MV) apparatus are and the Medium Voltage (MV) feeders leave from. The MV secondary power lines here interconnected are a part of the distribution network that powers the distribution transformers at or near the consumer premises.

3.2 – Introduction

3.2.1 – General Characteristics

The high voltage equipment and the medium voltage auxiliary systems are located in the substation yard, whilst the rest of the medium voltage equipment, together with the relaying, metering, and control devices, are placed inside the control house.

The power switchgear and instrument transformers for HV connect to terminal cabinets placed in the substation yard. The cable connection from the outdoor cabinets to the control house is accomplished by using cable trenches. The MV equipment is arranged in metal-clad cubicles inside the control house. These can either be single-aisle or double-aisle depending on the equipment arrangement and circuit layout.

The relaying, metering, and control equipment is mounted on control and relay panels installed within the control house. The panels are available on a variety of types, 19-inch racks are commonly used, and usually a separate panel is allocated for each circuit. Panels are arranged in readily accessible manner, and provide ample space for relay installation, removal, operation, and testing.

Shunt Capacitor Banks at substations improve power factor and voltage conditions by supplying leading kilovars to distribution systems. They are primarily used to improve the power factor in the network, but will also improve the voltage stability and reduce network losses. Improving the power factor also means a higher power distribution capability and increased control of the power flow. The installation of capacitors in a distribution network is called power factor correction or reactive power compensation [42].

Neutral Earthing Reactors (NERs) are employed in medium-voltage AC distribution networks to limit the current that would flow through the neutral point of a transformer in the event of an earth fault. NERs limit fault currents to a value that does not cause any further damage to switchgear or transformers beyond what has already been caused by the fault itself, and in some cases limit touch and step potentials to safer values than a solidly earthed systems. In addition, consideration is given to operation of protection relays within the required time.

All substations include auxiliary power supplies. AC power is required for substation building small power, lighting, heating and ventilation, some communications equipment, switchgear operating mechanisms, anti-condensation heaters and motors. DC power is used to feed essential services such as circuit breaker trip coils and associated relays, supervisory control and data acquisition (SCADA) and communications equipment [43].

3.2.2 – Relays & Control Panels Definition

The type of bay panels found in the high voltage cabinets and medium voltage cubicles of a given standard distribution substation, as well as their purpose, are listed under the following two sections [46] & [45].

High Voltage Cabinets

- HV Line / Power Transformer: responsible for the connection between the high voltage power line and the power transformer primary windings.
- High Voltage Power Line: provides a link between the high voltage busbar and its related high voltage power line.
- Primary Side Power Transformer: provides a link between the high voltage busbar and the primary windings of the power transformer.
- High Voltage Busbar Potential: provides a link between the high voltage busbar and its voltage instrument transformers.

- HV Switched Busbar Circuit-Breaker: responsible for the connection between one busbar and the other.

Medium Voltage Cubicles

- Secondary Side Power Transformer: responsible for the connection between the power transformer secondary windings and the medium voltage busbar.
- Medium Voltage Feeders: provides a link between the medium voltage busbar and its related medium voltage power lines.
- Medium Voltage Capacitor Banks: provides a link between the medium voltage busbar and the medium voltage capacitor banks.
- Station Services Transformers & Neutral Earth Reactors: provides a link between the medium voltage busbar and both the station services transformers and the neutral earth resistors.
- Medium Voltage Busbar Potential: provides a link between the medium voltage busbar and its voltage instrument transformers.
- MV Switched Busbar Circuit-Breaker: responsible for the connection between one busbar and the other.

3.2.3 – Relays & Control Devices Layout

The bay level equipment of the substation automation systems (bay units) are installed inside the operating room, distributed over the protection and control cabinets and the low voltage cubicles, and enclosed into standard racks that ensure easy installation and replacement.

The protection and control cabinets will host the bay units installed in the following bay panels [46]:

- HV Line / Power Transformer
- High Voltage Power Line
- Primary Side Power Transformer
- High Voltage Busbar Potential
- HV Switched Busbar Circuit-Breaker
- Alternating Voltage Station Services
- Direct Voltage Station Services

The low voltage cubicles will host the bay units installed in the following bay panels [45]:

- Secondary Side Power Transformer
- Medium Voltage Feeders
- Medium Voltage Capacitor Banks
- Station Services Transformers and Neutral Earth Reactors
- MV Busbar Potential
- MV Switched Busbar Circuit-Breaker

The station level equipment of the substation automation systems (Central Control Unit, Human-Machine Interface, and Communications Equipment) should also be installed in the operating room, but on a different cubicle according to the technical specification defined in the document [47].

3.2.4 – Equipment Layout

The next figure (Table 3.1) shows the switchgear' equipment mounted on the high voltage panels for each of the circuits.

Table 3.1 — Switchgear - HV Panel [38].

Switchgear	HV Panel				
	HV Line / Power Transformer	High Voltage Power Line	Main Power Transformer	HV Busbar Potential	HV Switched Busbar Circuit-Breaker
Voltage Instrument	1	1	—	3	—
Current Instrument	3	3	3	—	—
Power Transformer	—	—	1	—	—
Line Disconnecting	1	1	—	—	—
Busbar Disconnecting	—	1	1	—	2
Circuit Breaker	1	1	1	—	1
Surge Arrester (line-to-ground)	3	3	3	—	—
Surge Arrester (neutral-to-	1	—	1	—	—

The next figure (Table 3.2) shows which switchgear' equipment is mounted on the medium voltage panels of each circuit.

Table 3.2 — Switchgear – MV Panel [38].

Switchgear	MV Panel					
	Medium Voltage Feeders	MV Switched Busbar Circuit-Breaker	MV Busbar Potential	Station Services Transformers + Neutral Earth	MT Capacitor Banks	Medium Voltage Power Lines
Voltage Instrument	—	—	3	—	—	—
Current Instrument	3	—	—	3	3	3
Station Services Transformer	—	—	—	1	—	—
Neutral Earth Resistors	—	—	—	1	—	—
Shunt Capacitor Banks	—	—	—	—	1 or 2	—
Ground Disconnecting	1	—	—	1	1	1
Circuit Breaker	1	1	—	1	1	1
Surge Arrester (line-to-ground)	3	—	—	—	—	—
Surge Arrester (neutral-to-	1	—	—	—	—	—

3.2.5 – Bay Diagrams

The “HV Line / Power Transformer & Voltage Regulator” bay circuit has (1) voltage instrument transformer, (1) line disconnecting switch, (1)circuit breaker, (3) current instrument transformers, (7) surge arresters, and (1) power transformer, as shown in Figure 3.3.

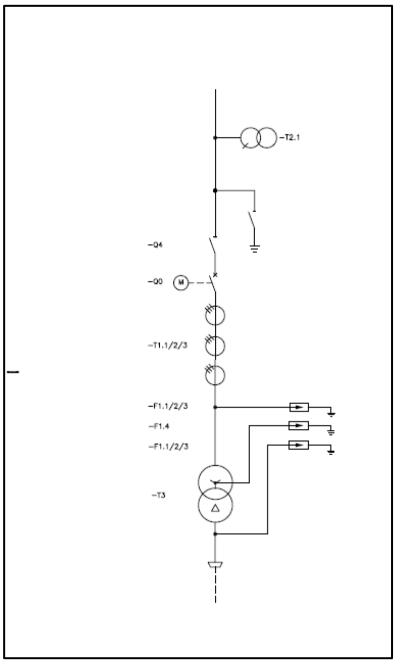

Figure 3.3 - HV Line / Power Transformer & Voltage Regulators [44].

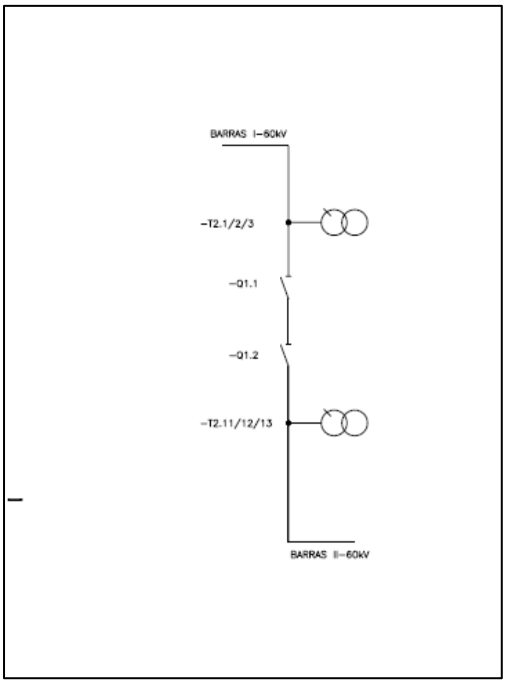

Figure 3.4 - Switched Busbar Circuit-Breaker + HV Busbar Potential [44].

As can be seen in Figure 3.4, the “Switched Busbar Circuit-Breaker + HV Busbar Potential” bay circuit has (3) voltage instrument transformers, (1) Switched Busbar I Disconnect Switch, (1) Switched Busbar II Disconnect Switch, and (3) voltage instrument transformers.

The “High Voltage Power Line” bay circuit has (1) busbar disconnect switch, (1) circuit breaker, (3) current instrument transformers, (1) line disconnect switch, (1) earth disconnect switch, and (1) voltage instrument transformer, as shown in Figure 3.5.

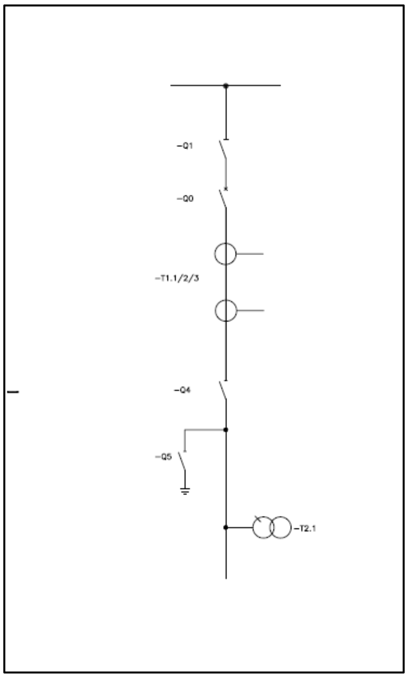

Figure 3.5 - High Voltage Power Line [44].

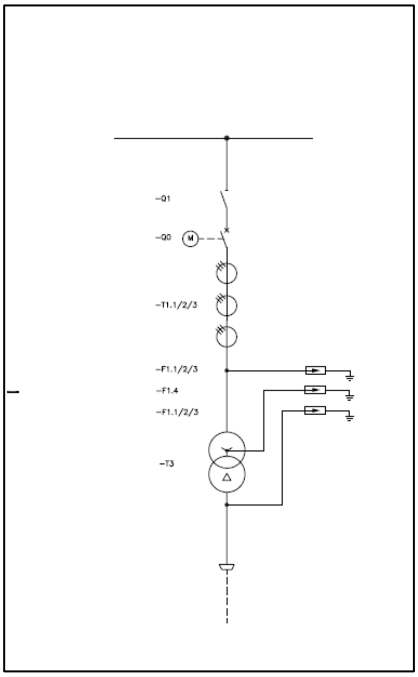

Figure 3.6 - Main Power Transformer & Voltage Regulators [44].

As can be seen in Figure 3.6, the “Main Power Transformer & Voltage Regulators” bay circuit has (1) busbar disconnect switch, (1) circuit breaker, (3) current instrument transformers, (7) surge arresters, and (1) power transformer.

The “HV Line Termination Structures” bay circuit has (1) disconnect switch, (3) current instrument transformers, (3) capacitive voltage dividers, and (1) earth disconnect switch, as shown in Figure 3.7.

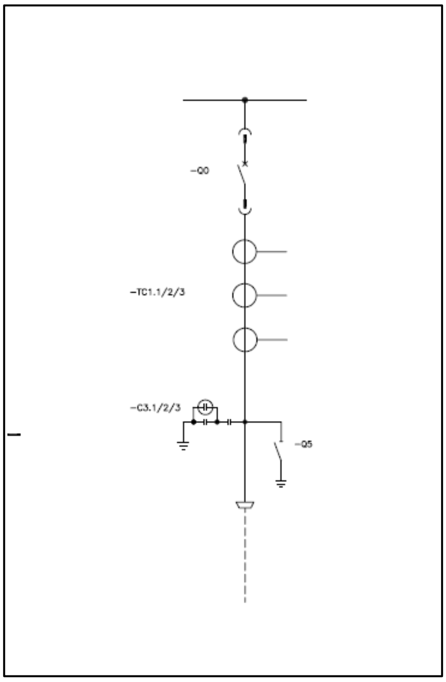

Figure 3.7 - HV Line Termination Structures [44].

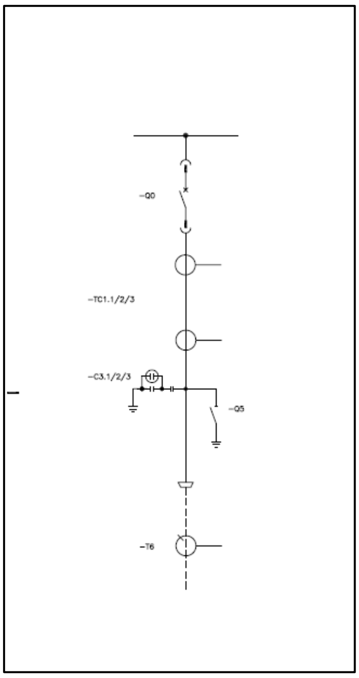

Figure 3.8 - Medium Voltage Power Line [44].

As can be seen in Figure 3.8, the “Medium Voltage Power Line” bay circuit has (1) disconnect switch, (3) current instrument transformers, (1) earth disconnect switch, (3) capacitive voltage dividers, and (1) toroidal current transformer.

The “HV Busbar Potential” bay circuit has only (3) voltage instrument transformers since its solely purpose is to measure the voltage on each of the three phases of the HV busbar, as shown underneath in Figure 3.7.

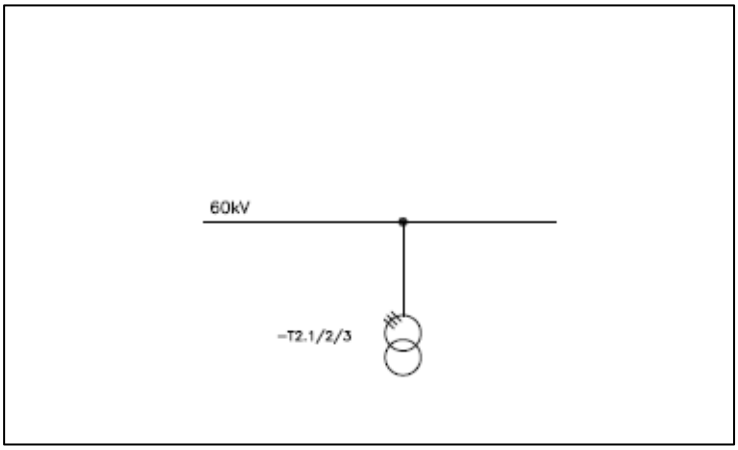

Figure 3.9 - HV Busbar Potential [44].

3.3 – Protection, Monitoring and Control

3.3.1 – Physical System Architecture

The Substation Automation Systems are responsible for the protection, monitoring and control of all electric process within an electric substation. The architecture is distributed over a communications network that connects all protection and control units. These intelligent electronic devices run a series of protection, automation, and command functions assuring that the substation works according to what is expected.

The architecture of the substation automation systems can be mapped into a three levels hierarchical model: process level (level 0), bay level (level 1), and station level (level 2). The process level consists of all HV/MV switchgear as well as instrument transformers. The bay level comprises all protection, monitoring and control devices. The station level is composed by the local control centre, the human machine interface, and the engineering station.

The communication between (level 0) and (level 1) devices is established over several point-to-point links and uses copper wires as the physical transmission medium. On the other hand, the communications within the intelligent electronic devices (level 1), and between them and the local control centre (level 2), relies on a local area network which is implemented over fibre optic cables.

The substation automation systems should also guarantee that all data gathered from the process level equipment, as well as all commands generated by the bay level units, is made readily available to the remote control centre (network level), so that the substation can be remotely monitored and controlled.

Finally, both the system architecture and its organizational structure are based on digital technology and a distributed processing environment which makes the system reliable, flexible, modular and simple to expand [38].

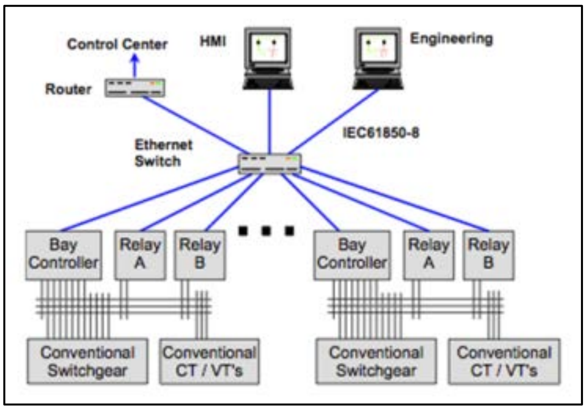

Figure 3.10 - Present Substation Automation System Architecture [12].

Process Level – The equipment found at this level includes all the HV and MV switchgear as well as the current and voltage transformers. Its main purpose is to acquire data from the electric processes and to make switching operations in a way to protect the substation equipment from overloads or faults.

Bay Level – This level consists of all intelligent electronic devices responsible for the protection and control of all the electric processes. Each device has its own self-diagnosis system that continually checks the state of all hardware drivers and software modules (watchdog).

Station Level – The purpose of this level is to assure the supervision, monitoring, command and control of all the substations' equipment and processes both locally and remotely. The central control unit can either consist of a Remote Terminal Units (RTU) or a Programmable Logic Controller (PLC) solution in addition to a Human-Machine Interface and an Engineering Station.

Station Bus – The local communications network responsible for the connection between all bay units and the connection between bay units and the control centre relies on a fibre-optic infrastructure to guarantee a transmission speed high enough to satisfy the demanding transfer time requirements of time-critical services such as trip signals and sampled values.

Process Bus – As of today, protection and control devices are connected to the switchgear and instrument transformers by parallel copper wires and communications are restricted to analogue signals. This is, however, expected to be replaced by an all-new communication architecture where fibre-optic cables and digital signals will become the standard.

3.3.2 – Logical System Architecture

Protection Functions

Each of the bay protection and control units, which integrate the substation automation systems, should perform a set of typical protection functions intended to monitor the network and ensure its correct operation, thus preventing and recovering from power outages quickly by detecting and clearing electric faults, and assuring increased functionality, reliable operation, and personnel safety [38].

To achieve these objectives the protection functions should respect the following principles:

- Selectivity: to minimize the affected area of the electric grid;
- Redundancy: to overcome the malfunction of any component of the system;
- Interoperability: to allow the coexistence with the rest of the automation features.

Time-critical services such as the transmission of trip-type signals, and sampled analogue current and voltage values, between protection and control devices, and the switchyard equipment, impose demanding time requirements. Transfer times down to 3 ms, and time synchronization in the order of 1 us, lead to the popular use of copper wires as the physical communications medium.

The following chart shows the protection functions implemented in each of the bay units (Table 3.1).

Table 3.3 — Protection functions implemented in each of the bay unit devices [38].

Protection Functions	Protection & Control Panels								
	HV Power line	HV Feeder	Main Power Transformer	MV Feeders	Shunt Capacitor Banks	MV Power Lines	Station Services Transformer + Neutral Earth Resistors	Station Services Transformer (Isolated Neutral)	HV Line / Power Transformer
Overcurrent protection	x		x	x	x	x	x	x	x
Distance protection	x								
Differential protection	x	x	x						x
Overvoltage protection				x	x		x	x	
Undervoltage protection		x		x					
Directional Overcurrent	x					x			
Frequency protection				x					
Earth Fault Protection	x				x	x	x		

Control Functions

The substation automation systems must perform, altogether with the protection functions, and preferably in a distributed manner, a set of typical automation functions with the purpose of detecting and clearing electric faults and thus ensure high quality of service [38].

For further details on the technical characteristics and sequence of operations of the automation and control functions implemented in each bay unit of a given voltage level of a substation one should check the functional specifications document.

The implementation of the automation and control functions are intended to be distributed across multiple bay units which are connected through a LAN sharing information in real time. Given that, each bay unit device is responsible for a set of particular tasks as listed below in (Table 3.3).

Table 3.4 — Automation functions implemented in each of the bay unit devices [38].

Control Functions	Protection & Control Panels					
	HV Power line	HV Power Transformer	MV Power Transformer	Shunt Capacitor Banks	MV Power Lines	HV Line / Power Transformer
Undervoltage Load-shedding (HV)	x	x	x			x
Undervoltage Restoration (HV)	x	x	x			x
Automatic Voltage Regulator (MV)		x				
Undervoltage Load-shedding (MV)				x	x	
Undervoltage Restoration (MV)					x	
Underfrequency Load-shedding				x	x	
Underfrequency Restoration					x	
MV Reclosure Functions					x	
High Speed Reclosure (HV)	x					
Shunt Capacitor Banks Controller				x		
Earth Fault Location			x	x	x	

The substation automation system must ensure that all bay units connected through the local area network share information in quasi real time thus guaranteeing the correct execution of every automation function within the critical time limit set for each other.

3.4 – System Functionalities

In the following two subsections one shall see the working principle and operating mode of both the protection and control functions referred in the previously section (2.4.2).

3.4.1 – Protection Functions

The main protection functions implemented by the substation automation systems are described below [49].

- Overcurrent protection (ANSI 50)

  Phase-overcurrent protection (ANSI 50) detects overcurrents caused by phase-to-phase faults. It uses the measurements of the fundamental component of currents drawn from two or three phase CTs, with a secondary rating of 1 A or 5 A. Earth-fault protection (ANSI 50N) detects overcurrents caused by phase-to-earth faults. It uses measurements of the fundamental component of the earth-fault current.

- Distance protection (ANSI 21)

  The Distance protection responds to a combination of both voltage and current. The voltage restrains operation, and the fault current causes operation that has the overall effect of measuring impedance. Distance protection works against faults affecting line or cable sections and is used in meshed power systems. It is selective and fast, without requiring time-based discrimination. Sensitivity depends on the short-circuit power and the load. It is difficult to implement when the type of link is not the same throughout. It operates according to the following principle: (i) measurement of an impedance proportional to the distance from the measurement point to the fault; (ii) delimitation of impedance zones which represent line sections of different lengths; (iii) tripping by zone with time delay.

- Differential protection (ANSI 87)

  Differential protection (ANSI 87B) is based on the vector sum of the current entering and leaving the equipment for each phase. When the equipment is fault-free, the sum is equal to zero, but when there is a fault on the equipment, the sum is not zero and the equipment supply circuit breakers are tripped.

- Overvoltage protection (ANSI 59)

  Protects against overvoltages or checks for sufficient voltage and then enables source transfer. Operation with phase-to-neutral or phase-to-phase voltage depends on the connection selected for the voltage inputs.

- Undervoltage protection (ANSI 27)

  Protects equipment against voltage sags or detects abnormally low network voltage and then triggers automatic load shedding or source transfer. Operation with phase-to-neutral or phase-to-phase voltage depends on the connection selected for the voltage inputs.

- Directional Overcurrent (ANSI 67)

  This function comprises a phase overcurrent function associated with direction detection and picks up if the phase overcurrent function in the chosen direction (line or busbar) is activated for at least one of the 3 phases (or two of the three phases, depending on the settings).

- Frequency protection (ANSI 81)

  Detection of abnormally high or low frequency compared to the rated frequency, to monitor power supply quality. The protection may be used for overall tripping or load shedding.

- Thermal & Overload (ANSI 49)

  Protection that detects abnormal heat rise by measuring the temperature inside equipment fitted with sensors. This function is used to protect equipment (e.g. transformers and capacitors) against overloads, based on measurement of the current drawn. This protection function provides as well protection against overheating due to overload currents in conductors (e.g. lines and cables) under steady state conditions, by estimating temperature build-up according to the current measurement.

3.4.2 – Control Functions

The main automation and control functions implemented by the substation automation systems are described below [48].

- Load Shedding [48]

  (Undervoltage/Underfrequency Load-shedding and Restoration)

  The load shedding function is used when a shortage of available power in comparison to the load demand causes an abnormal drop in voltage and frequency. Certain consumer loads are disconnected according to a preset scenario, called a load shedding plan, in order to recover the required power balance. Different load shedding criteria may be chosen: undervoltage (ANSI 27); underfrequency (ANSI 81L); rate of change of frequency (ANSI 81R). The two most common functions are: the Undervoltage Load-shedding and Restoration (UVLS), and the Underfrequency Load-shedding and Restoration (UFLS).

- Recloser function [48]

  The recloser function (ANSI 79) is designed to clear transient and semi-permanent faults on overhead lines and limit down time as much as possible. The recloser function automatically generates circuit breaker reclosing orders to resupply overhead lines after a fault. This is done in several steps: (i) tripping when the fault appears to de-energize the circuit; (ii) time delay required for insulation recovery in the location of the fault; (iii) resupply of the circuit by reclosing. Reclosing is activated by the link protection units. The recloser may be single-phase and/or 3-phase, and may comprise one or more consecutive reclosing cycles.

- Earth Fault Protection [48]

  The earth fault protection function is a backup protection designed to identify permanent faults not previously detected, due to lack of sensitivity, by the main protection functions of a given feeder or busbar. The earth fault location function, when triggered by a given protection, uses the recloser function to, by trial and error, sequentially search and identify the feeder under fault, and then isolate and clear the fault selectively, while leaving the remaining loads being supplied.

- Automatic Voltage Regulator [48]

  The Automatic Voltage Regulator (AVR) function is used to maintain a stable voltage on the load side of the power transformer under varying network load conditions. The function measures the voltage on the secondary side of the power transformer to determine whether the voltage needs to be increased or decreased, and then controls the voltage by sending raise or lower commands to the on-load tap-changer of the power transformer.

- Capacitor Bank Controller [48]

  Shunt Capacitor Banks are a simple and cost effective way of improving power factor being commonly used to reduce reactive impedance fluctuations on distribution lines.

The operation of the distribution system at a near unity power factor helps to improve the efficiency of the system, and to improve the economics related to power handling.

3.4.3 – Other Functions

- Breaker Failure [48]

  The breaker failure function (ANSI 50BF) provides backup when a faulty breaker fails to trip after it has been sent a trip order: (i) the adjacent incoming circuit breakers are tripped.

- Auxiliary Systems Control [48]

  The auxiliary systems control function is used to control the station services transformers, providing a backup power supply to the substation emergency systems, in the event of an AC supply failure.

3.5 – Applications & Services

The automation system comprises a set of applications and services that go far behind the supervisory control and data acquisition (SCADA) features. Among them are functionalities that allow the remote configuration, customisation and data gathering from the bay unit devices and the local control centre as well as communication within the station level devices.

3.5.1 – Primary Applications

The main applications and services provided by the substation automation systems are described in the following bullet points.

- SCADA

  The supervisory control and data acquisition service makes it possible to locally or remotely perform the supervision and control of the substation and its equipment.

- Telemetry

  The telemetry service is used to measure the amount of electrical energy consumed. Electricity meters from each of the bays gather data on a daily basis and send it to the energy provider’s server. This information is initially coded and then transmitted over GPRS, GSM or even phase line carrier systems making it available from a remote location.

- Online Engineering

  The online/remote engineering service makes it possible to remotely change the configuration parameters and the operation mode of the protection, automation and control functions. It also enables the remote access to the data recorded on the events registry and disturbance recorder modules of each bay unit.

The online/remote engineering service similarly makes it possible to configure and customise the control centre features from a given remote workstation, enabling as well the access to the data produced by the condition monitoring modules further allowing the remote execution of a fault diagnosis or failure analysis.

This service is performed on demand from the central engineering room or the Network Operations Centre (NOC)

- Equipment Supervision

  This service is responsible for monitoring the condition of some equipment, such as the Station Services Transformers and the Direct Voltage Batteries, by remotely performing diagnostic routines and taking maintenance actions. Among the actions taken is the change of settings with the solely purpose of improving performance or preventing future problems like wear and tear.

  In the case of the emergency power system above mentioned, some of the features implemented include the remote access to the transformers data and the battery status, as well as the execution of complete battery charge and discharge cycles to increase the batteries lifetime.

  Under the standard specifications for substations framework [38], there might be several apparatus within a substation that support this type of features and therefore prone to have their maintenance service shifted from local to remote.

- Teleprotection

  The teleprotection service ensures the point-to-point digital connection between two or three different facilities so that some protection functions which depend on data from more than one substation can be executed.

3.5.2 – Support Services

The secondary applications and services which are not directly provided by the substation automation systems are described in the following bullet points:

- Video Surveillance / Intrusion Detection

  The Video Surveillance and Intrusion Detection system is a combined system designed to detect unauthorized entry into the substation area and automatically record the activities of intruders. This system uses closed-circuit television (CCTV) surveillance cameras combined with microwave and infrared detectors for the given purposes. The video cameras transmit the recorded footage to a centralised monitoring centre where they can be seen on a limited set of monitors. In addition, there is also a fire alarm system which is equipped with optical fire sensors.

- Telephone

  The telephone service has the basic function of allowing reliable voice communications between the network operations centre, local control room, and the on-site personnel which sometimes are under rugged environments and conditions.

- Remote Assistance

  Video cameras should be used at modern substations to observe and record parts of a process from a central control room. From there multiple authorities would be able to view and control the cameras in real time in order to find possible causes of malfunctions. Field technicians could then get remote assistance from off-site personnel by directing them to the camera and visually showing the problem remotely. A service like this, running on demand from a remote support centre, would be especially useful in helping with the troubleshooting and problem solving.

- Quality of Service Monitoring

  The disturbance recorder module is used together with the protection and control relays providing a tool for the network operating personnel to analyse the performance of the power system and the response of the substation equipment when a network disturbance situation occurs.

  Fast detection of a network problem and correct assessment of the network behaviour followed by rapid corrective measures helps achieve high power system reliability and availability and thus leads to a better quality of power supply.

3.6 – Summary

Electrical Substations are installations used for the transmission and distribution of electrical energy. Their main purpose is to transfer and transform the electrical energy by stepping-up or stepping-down the voltage. A standard installation has power transformers, switching equipment and instrument transformers, as well as the substation automation systems for protection, monitoring and control.

The high voltage equipment and the medium voltage auxiliary systems are located in the substation yard, whilst the rest of the medium voltage equipment, together with the relaying, metering, and control devices, are placed inside the control house. The medium voltage equipment is arranged in metal-clad cubicles inside the control house. These can either be single-aisle or double-aisle depending on the equipment arrangement and circuit layout. The relaying, metering, and control equipment is mounted on control and relay panels installed within the control house. The panels are available on a variety of types, 19-inch racks are commonly used, and usually a separate panel is allocated for each circuit. The central control unit, the human-machine interface, and the communications equipment is also installed within the control house but mounted on a different cabinet.

Shunt capacitor banks at substations improve power factor and voltage conditions by supplying leading kilovars to distribution systems. Neutral earthing reactors are employed in medium-voltage AC distribution networks to limit the current that would flow through the neutral point of a transformer in the event of an earth fault. All substations include as well station service transformers and AC/DC auxiliary power supplies.

The substation automation systems are responsible for the protection, monitoring and control of all electric process within an electric substation. Both the system architecture and its organizational structure make the system reliable, flexible, modular and simple to expand.

The architecture of the substation automation systems can be mapped into a three levels hierarchical model with a process level (level 0), a bay level (level 1), and a station level (level 2). The process level consists of all HV/MV switchgear as well as instrument transformers. The bay level comprises all protection, monitoring and control devices. And the station level is composed by the local control centre, the human machine interface, and the engineering station.

The communication between (level 0) and (level 1) devices is established over several point-to-point links and uses copper wires as the physical transmission medium. The communications within the intelligent electronic devices (level 1), and between them and the local control centre (level 2), relies on a local area network which is implemented over fibre optic cables. The substation automation systems should also guarantee that all data is made readily available to the remote control centre (network level).

Each of the bay protection and control units, which integrate the substation automation systems, should perform a set of typical protection functions intended to monitor the network and ensure its correct operation, thus preventing and recovering from power outages quickly by detecting and clearing electric faults, and assuring increased functionality, reliable operation, and personnel safety.

The substation automation systems must perform, altogether with the protection functions, and preferably in a distributed manner, a set of typical control and automation functions with the purpose of detecting and clearing electric faults, and thus ensure high quality of service.

The automation system comprises a set of applications and services that go far behind the supervisory control and data acquisition features. Among them are functionalities that allow for the remote configuration, customisation and data gathering from the bay unit devices and the local control centre as well as communication within the station level devices.

Chapter 4

Process Bus Implementation

In this fourth chapter, Process Bus Implementation, we shall see what the process bus is, and why its implementation is so critical for the evolution process of electrical substations and substation automation systems.

Starting with a brief introduction about the historical evolution of substation automation, it will be seen that the next step comes with the process bus implementation. It will then be analysed the present background found at the distribution network operator in Portugal, and identify the main drivers that shall lead us to implement such a process bus. Main benefits, technical issues, and suggested future architecture are among the topics covered. Following this, the focus will turn to the novel optical sensors and intelligent switchgear technology that comes along with the process bus. However, it is know that these new sensors require a digital interface to work, and because of this we will be introducing two other devices, the merging units and the breaker IED.

Finally, the last section of this chapter is going to analyse what the path from the present to the future architecture should be. The focus will be solely on the network topology, and coming from a general implementation overview, we will then dig up on the field topology details. At last, we will go over some possible future issues like reliability, redundancy, verification, validation and testing.

4.1 – Introduction

Substation automation systems (SAS) are used to control, protect and monitor a substation. Recent advances in electronics, information technology and communication, provided technical solutions that revolutionised the way substations operate.

Initially, digital technology was introduced to substations with the purpose of providing communication channels between the substations and the remote control centres. Later on, in the 1990s, with the developments in the computing and communication fields, and the increased capacity and speed of electronic devices, new digital devices for protection and control come up.

These novel bay units gradually replaced the old electromagnetic relays in use at substations, and digital communications were implemented at the station level, making possible the communication between these electronic devices. However, different protocols were in use and there was the need for a communications standard to ensure a high level of compatibility and interoperability between equipment from different manufacturers.

It was only In 2004 that this came to happen, with the release of the IEC 61850 standard, which brought an all-new concept into communications, and for the first time defined a communications architecture that supports both a station and a process bus.

4.2 – The Process Bus

The process bus is defined in IEC 61850 as the new standard for communications between primary and secondary equipment. The process bus interconnects the intelligent electronic devices (IEDs) with both the instrument transformers and the switchgear equipment, and mainly carries measurements and signals for protection and control.

Fibre optic cables replace copper cables as the traditional physical medium, and the transmission of analogue samples is made across an Ethernet-based serial link. Besides transmitting current and voltage samples, the link also transmits switch positions, commands and protection trips. Typically sampled values (SV) are used to transfer data between bay level and process level, and values are sampled at a nominal rate of 4 kHz in 50 Hz grids.

4.2.1 – Historical Background

Since the majority of the substations were built in Portugal, more than 30 years ago, there has been a huge development on both the primary equipment, i.e. switchgear and instrument transformers, and on the secondary equipment, i.e. protection, monitoring and control devices.

Meanwhile, both utilities and vendors already widely adopted the station bus as the standard secondary system for the communication between station and bay level devices, and replaced the rigid parallel copper wiring by serial links architectures for the connections within bay level devices, and between them and station level devices [49].

However, the connection of the automation systems with the instrument transformers and switchgear equipment is still left to analogue signals and contact circuits; thus the opportunity to upgrade the interconnection between sensors, actuators, and protection and control devices, to a digital interface.

In addition, it is widely accepted that, the latest step in the evolution of substation automation systems comes with the implementation of the IEC 61850 standard for the process bus interface. Finally, as shall be see next, the implementation of the process bus brings along serious advantages, and provides an opportunity to re-design the way new substations are built, as well as to retrofit the ones currently in operation.

4.2.2 – Main Benefits

The introduction of the IEC 61850 process bus standard in substations will give the following main advantages [49]:

- The footprint of primary switchgear can be reduced since fibre optic sensors (NCIT) can replace conventional measuring transformers;
- By using new sensor technology for voltage measurement the equipment can be made much lighter, and its manufacturing time can be reduced;
- On the secondary side there will be a massive reduction of secondary cabling as result of the physical change from copper cables to fibre optic cables;
- By replacing many copper cables by a few fibre optic communication cables it will mean reduced costs for cables and associated equipment;
- This will lead to higher quality overall and a reduced time at site, since most site acceptance tests (SAT) can be replaced by factory acceptance tests (FAT);
- Changing to optical sensors (NCIT) will increase personnel safety, avoiding the risk of intentionally opening a current transformer circuit;
- It will be a big advantage during the retrofit process, reducing outages to a minimum, since conventional wiring links can work in parallel during the replacement process;
- Optical cables achieve the galvanic decoupling of primary and secondary equipment, which makes maintenance and replacement easier;
- The serial interface makes the applications independent of the physical principle of the instrument transformer (electromagnetic, capacitive, optical, others) allowing more flexibility on the primary equipment side.

Another advantage of the process bus is that, with electrical and process data from the entire substation readily available, maintenance policies can shift from reactive and preventive to predictive methodologies. This is true since the system itself can monitor the condition of the assets and report when a component needs servicing or replacing. We shall see further details on this topic in chapter 5.

4.2.3 – Technical Issues

The introduction of the IEC 61850 process bus standard in substations also imposes some technical issues [49]:

- There is the need for a secondary system to support both conventional and non-conventional instrument transformers during the initial transition period;
- It is necessary to use electronic interfaces with circuit breakers and disconnect switches to convert switch positions, commands, and protection trips from electric to digital;
- The bandwidth requirements are quite high since the process bus needs to continuously transfer sampled values from the primary process with a quasi real-time response;
- The dynamic behaviour (step and frequency response) of merging units, and the extent to which output signals differ from input signals due to digitalization, is yet to be defined;
- High-precision time synchronization is required across the automation network, which can be achieved by using synchronous sampling or by time tagging each sample with a GPS;
- Cyber Security is a big issue, since it is necessary to protect the system from pirate intrusion attacks, which could compromise data security, consistency and integrity.

The choice for a specific process bus architecture can also be quite complex since it depends on factors such as the distance and location of the MU and IEDs, the communication capabilities (single port, multiple ports) of the units, the network bandwidth, the network availability, and the communication topology (point-to-point, star, or ring) among others [49].

4.2.4 – Future Architecture

The introduction of the IEC 61850 communication standard for substation automation makes it possible the interoperation between protection, monitoring and control devices, no matter their manufacturers, on the same local area network, station or process bus, by using a standard protocol over serial communication links.

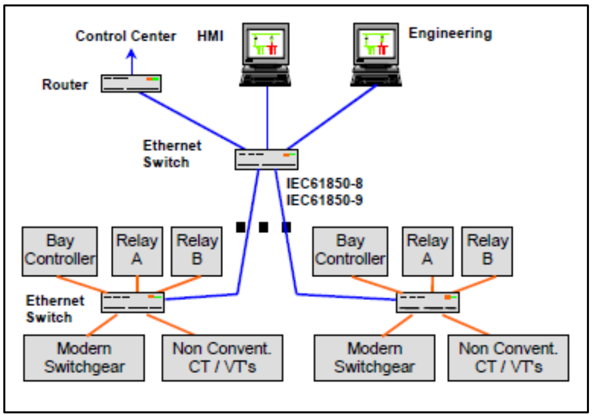

Figure 4.1 - Substation wide area network with a merged station/process bus and a communication architecture, which is fully compliant with the IEC61850 standard [12].

Since the same communication technology is used for the station bus as well as the process bus, data access is possible within all substation levels, making it possible to adopt system architectures like those seen in Figure 4.1. These architectures can either be based on a star topology, or on a ring topology. The number of switches used to connect the main protections, backup protections, control IEDs, and field units, depends on the network topology adopted for each voltage level.

4.3 – Sensors and Actuators

The implementation of such a process bus opens a door to an all-new range of novel sensors and actuators on the primary equipment side. In fact, new fibre-optic sensors can now replace the conventional instrument transformers (CIT) made of cooper, iron and insulation material, which have analogue output signals of either 1A or 110V.

These non-conventional instrument transformers can be either galvanic ones, like Rogowski coils and capacitive voltage dividers, or optical ones, like magneto-optic current transformers (MOCT) and Fibre Optical Voltage Transformers (FOVT). They send process bus compatible digital signals through fibre optic cables and impose new requirements on the interface with protection relays and control units.

4.3.1 – Novel Instrument Transformers

Most of the instrument transformers in use nowadays are based on electromagnetic principles and have a magnetic core, but there are now available several novel sensors, which are based on optical and mass state methods.

Likewise legacy instrument transformers, these novel sensors are equally used to convert large currents and voltages from the primary side to an appropriate signal for secondary equipment, and to protect secondary equipment from the harmful effects of large currents and voltages that might occur on the primary side during a short circuit in the network [42].

In addition, non-conventional optical transducers are much smaller and lighter than electromagnetic instrument transformers since the size and the complexity of the sensor does not depends on the power rating of the unit. In fact, the optical sensing devices can easily be fitted into small, lightweight insulator structures, or even bundled into circuit breakers or disconnect switches. Besides the obvious advantages of lessening the cost of the units and reducing the layout of the substations, these new sensors are also immune to non-linear effects and electromagnetic interference problems.

Current sensors based on the Rogowski coil principle use a uniform winding on a closed circular support with a constant cross section and no ferromagnetic core, as shown in Figure 4.2. In this case, the voltage induced in the winding (the transmitted signal) is directly proportional to the variation in the let through current [42]. These current sensors are characterized by the absence of saturation and hysteresis phenomena as well as an excellent linearity of the output measurements because there is no iron in the Rogowski coil.

Voltage sensors based on the capacitive divider principle use for voltage indication a cylindrical metal electrode moulded into the sensor and facing the insulator bushings, as can be seen in Figure 4.3. In this case, the output signal is a voltage directly proportional to the primary voltage [42]. As with the current sensors, the voltage sensors are also characterized by the absence of Ferro-resonance phenomena and insensitivity to the effects of DC components.

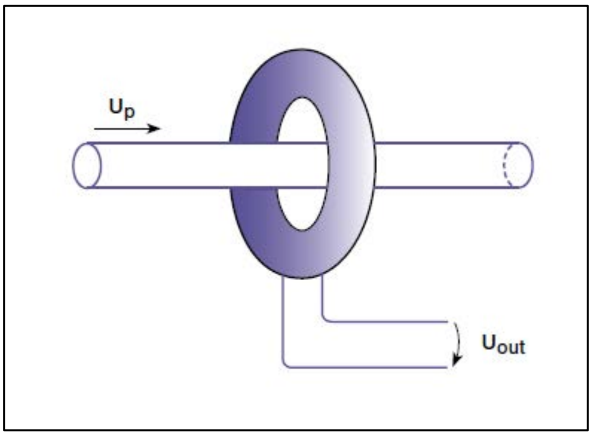

Figure 4.2 - Rogowski coil principle [42].

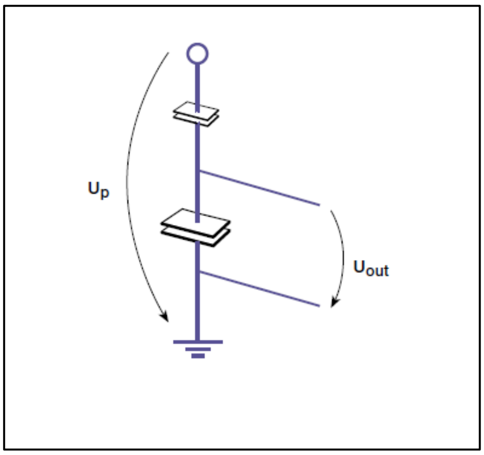

Figure 4.3 - Capacitive divider principle [42].

Most optical current transducers use magneto-optic effect sensors to measure currents since sensors are not sensitive to currents, but to the magnetic fields generated by those currents. On the contrary, optical voltage transducers rely on electro-optic effect given that the sensors used are sensitive to the imposed electric fields [43].

In optical current sensors the sensing element, made of an optical material, is either located free in the magnetic field, or immersed in a field shaping magnetic ‘gap’ as shown in Figure 4.4. For optical voltage-sensors the working principle is similar but based on the electrical properties of optical materials, as can be seen in Figure 4.5 [43].

Since these transducers are quite small and lightweight, it is possible to combine both current and voltage sensors within a single device, thus reducing the layout needed for substations.

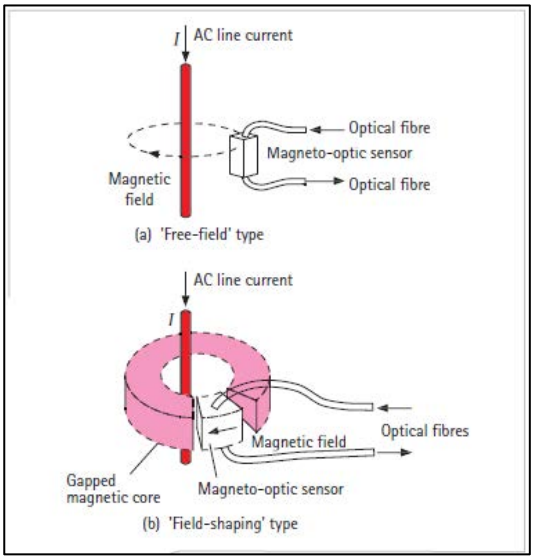

Figure 4.4 - Optical current sensor [43].

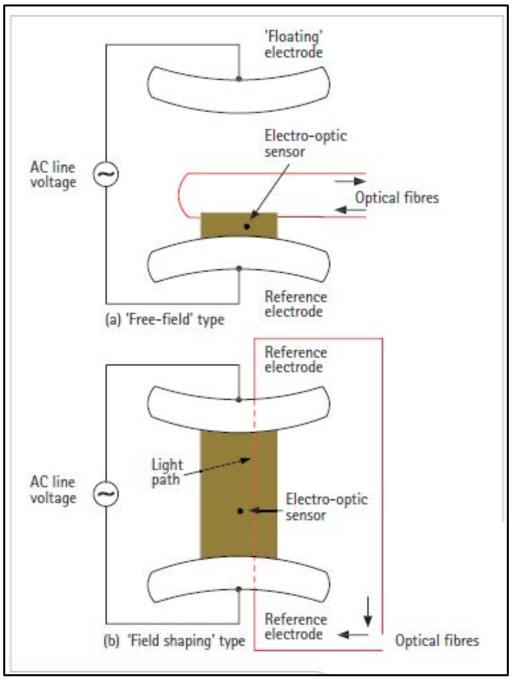

Figure 4.5 - Optical voltage sensor [43].

There are several advantages on using these novel instrument transformers like the linearity of measurements and versatile protection, the safety offered, the small power consumption, and in that they are environmentally friendly solutions. However, and despite its introduction being traced back to the middle 1990s there are still only few of them in service nowadays. Nevertheless, this is due to change with the implementation of the process bus, and the general adoption of combined optical current/voltage transformers.

4.3.2 – Disconnecting Circuit Breakers

Circuit breakers with a revolutionary design are making their way into the market changing the way switchgear configuration and integration used to be, and resulting in cost savings both in terms of land and equipment.

Since each circuit breaker needs two disconnect switches for safe isolation they usually account for most of the space needed in the substations switchyard. On the other hand, SF6 circuit breakers of the self-blast and/or puffer type are a well-established technology. This brings along an opportunity to combine both devices into a single unit thus simplifying substations and saving space.

In fact, some equipment suppliers already developed and manufactured a new device named disconnecting circuit breaker (DCB), which has been claimed to save equipment cost, reduce footprint and construction costs, and increase availability. In addition, these disconnecting circuit breakers are frequently embedded with intelligent breaker IEDs specifically designed to be compatible with the IEC 61850 standard. By taking advantage of this, protection and control bay units can use the same fibre-optic links for measurement samples and trigger signals, resulting in a more reliable and cost efficient automation system.

It is then clear that, substations can become more reliable and cost efficient with the introduction of new equipment and technology such as the combined disconnecting circuit breaker, which greatly improves efficiency in substation construction, operation and layout, and together with an intelligent interface, also enables the implementation of the process bus [46].

4.4 – Switchgear Digital Interfaces

The forthcoming replacement of legacy sensors by digital ones, as a result of the process bus implementation, creates the need for a secondary system to support both conventional (CIT) and non-conventional (NCIT) instrument transformers during the transition period. This is further supported by the necessity for handling signalling commands and position indications to and from primary switchgear.

For new installations and even more important when retrofitting or extending existing substations, since new bays will have NCIT and existing bays CIT, both sensor and conventional instrument transformer technologies will need to co-exist side-by-side. In fact, the last case is the most obvious taking in account the typical life cycle of the primary equipment.

Both merging units (MU) for optical sensors, and interface units (IU) for conventional instrument transformers will be introduced. Additionally, switchgear controllers for circuit breakers and disconnect switches, the so-called "Breaker IEDs", will be needed. Those devices will serve as conversion "endpoints" between the primary process and the secondary equipment.

4.4.1 – Merging Unit

A merging unit (MU) has the purpose of converting the proprietary signals from non-conventional instrument transformers, or the analogue values from conventional instrument transformers, to a format compliant with the IEC 61850 standard. This electronic device merges current and voltage data from three phases into a single output signal, so that six phase sensors can rely on a single unit, which transforms the input electrical signals into digital sampled values, Figure 4.6.

The merging unit (MU) works at the process level connecting the protection and control devices to the instrument transformers, which can be conventional voltage and current transformers, nonconventional voltage and current transformers, or even a mix of both. Despite the sensors interface with the merging unit being technology specific, the output signal, available to the process bus, should be in accordance with the IEC 61850 recommendations.

Merging units (MU) are used to deliver all current and voltage samples for a given bay in a time-synchronized manner. For that, voltages and currents from the three phases, together with the zero components, are sampled at a rate of either 80 or 256 samples per second, and then packed into an Ethernet datagram, ready to be transmitted over the process bus with a time synchronization of a pulse per second, and synchronization accuracy of 4 microseconds.

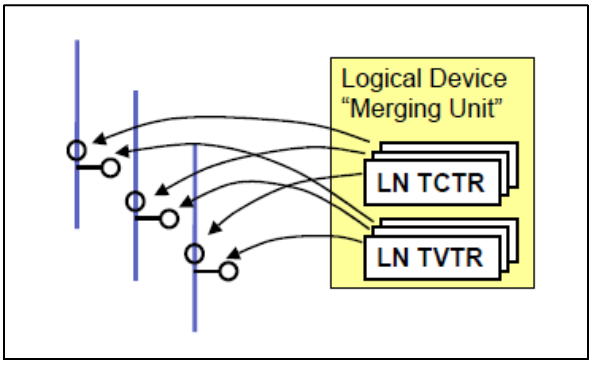

Figure 4.6 - Merging unit connected to 3 single-phase voltage and current transformers [12].

4.4.2 – Breaker IED

A breaker interface is an electronic device for handling binary, input and output, signals from and to circuit breakers and disconnect switches. Those electronic devices, often referred to as “Breaker IEDs”, are used to communicate status information and trip commands through the process bus. The Breaker IED can then be considered as an intelligent switchgear controller.

Recent advances in switchgear equipment, like operating mechanisms controlled by servomotors, lead to the inclusion of electronics in the primary equipment. This is a clear opportunity to fit the breaker drive with a communication interface compliant with the IEC 61850 standard. Finally, the use of those novel switchgear apparatus, containing electronic drives with communication capabilities, will make it possible to monitor the condition of the primary equipment online.

4.5 – Local Area Network Topology

The introduction of new technologies like those described in the previous sections will result in a more decentralised architecture of the substation automation systems, and will enable a considerable reduction of cooper wiring in the substations.

Conventionally connected substations have a large number of copper wires laid down between the switchyard and the control room. These can sum up to 500 wires per each bay, and besides the cost of implementation, they turn the project time consuming, and prone to failures. In addition, the amount of manual work required assembling and testing each wire individually, and needed to assure the consistency of the system drawings can be challenging.

The typical life cycle of the primary equipment ranges from 30 to 40 years, whilst for the secondary equipment it is in the 15 to 25 years interval. Thus, it is often necessary to replace the latter, one to four times, during the lifetime of the former. This also depends on the technology in use, namely whether it is a conventional remote terminal unit (RTU), or a proprietary numerical control system.

More evolution opportunities will then arise from the retrofitting or extension of existing installations, than from the construction of new substations. Because of this, the process bus implementation will have 3 stages according to an evolutionary process as explained in the following subsections.

4.5.1 – Process Close Implementation Overview

The present architecture (Figure 4.7) came up in the mid 1990s with the introduction of numerical relays and communication technology. This traditional approach is based on a station bus for communications at the bay level, which is compatible with the IEC 61850 standard. However, conventional wiring is used at the process level to transmit both analogue and binary data.

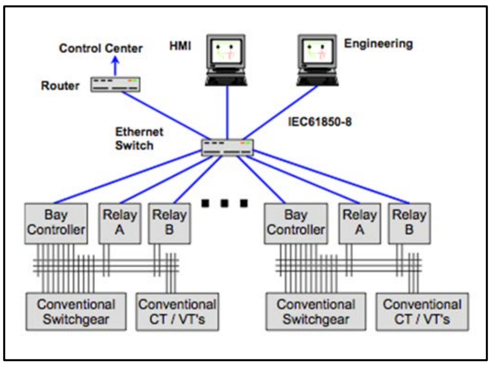

Figure 4.7 - Present architecture using both a station bus and conventional wiring links [12].

Firstly, there will be an introduction of non-conventional instrument transformers, connected to the protection and control devices via merging units and through serial point-to-point links as defined in the standard IEC 61850. The resulting architecture can be seen next in Figure 4.8.

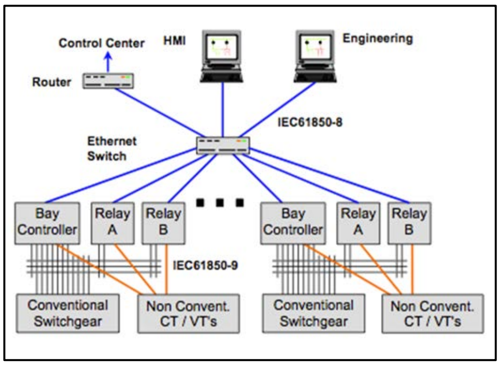

Figure 4.8 - Architecture with a station bus and links to non-conventional instrument transformers [12].

Secondly, with the integration of communication interfaces directly into the electronic drives of the switchgear equipment, it will be possible to replace the remaining cooper wires by fibre optic cables. As a result, logic links will replace conventional physical connections and communications between bay level devices and primary equipment will become digital, giving place to much simpler system architecture as shown in Figure 4.9.

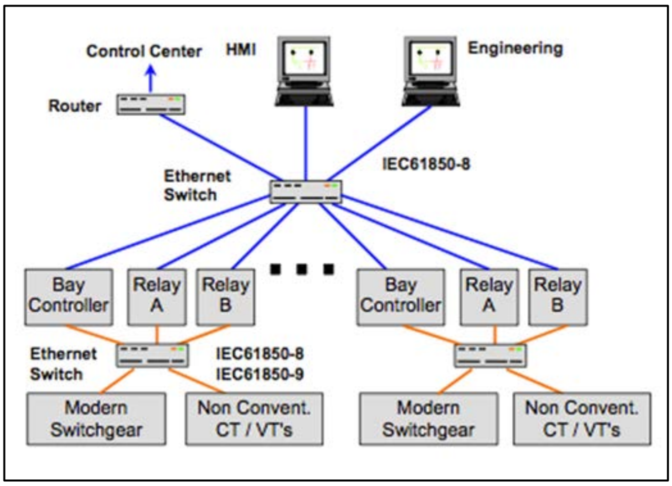

Figure 4.9 - Full process bus architecture with both a station bus at bay level, and a process bus using both non-conventional instrument transformers and breaker IEDs [12].

Finally, with the adoption of the same communication media, network topology, and communication protocol for the station and the process buses, will be possible to share data across all substation levels, thus enabling the use of much simpler and efficient system architectures as the one seen in Figure 4.1 (Section 4.2.3).

4.5.2 – Process Close Architecture Details

The process close architecture changes with the technology used in the switchyard to connect the primary equipment with the electronic devices for protection and control. These process close topologies depend on whether the instrument transformers and switchgear equipment are connected with conventional wires or via a digital network instead.

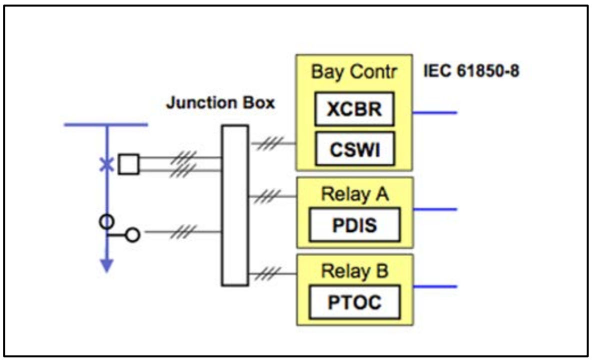

Figure 4.10 - Traditional approach with conventionally connected switchgear [12].

Figure 4.10 shows a typical situation where three IEDs, consisting of a bay controller, a main protection, and a backup protection, are conventionally connected to the primary equipment. Since a single copper wire is needed for the transmission of each electrical signal, from and to the electric apparatus, many cooper cables need to be installed in the switchyard with the purpose of transmitting all analogue signals and binary data.

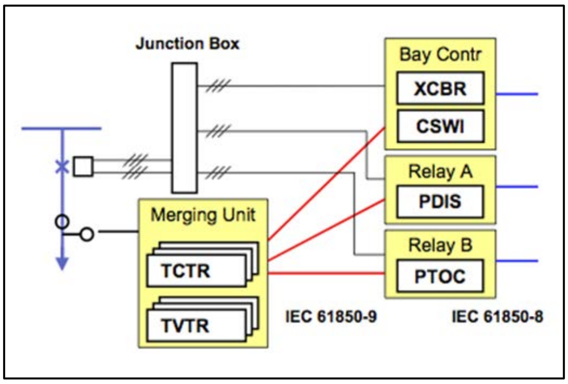

Figure 4.11 - Introducing new sensor technology with non-conventional instrument transformers [12].

The first step in the process bus implementation comes with the introduction of optical instrument transformers like MOCT and FOVT. These novel sensors will connect to the protection and control devices via merging units as can be seen in Figure 4.11. While connections from optical sensors to merging units might use proprietary protocols, from merging units to bay level devices they must follow the IEC 61850 standard. These can be several point-to-point serial links or a switched network.

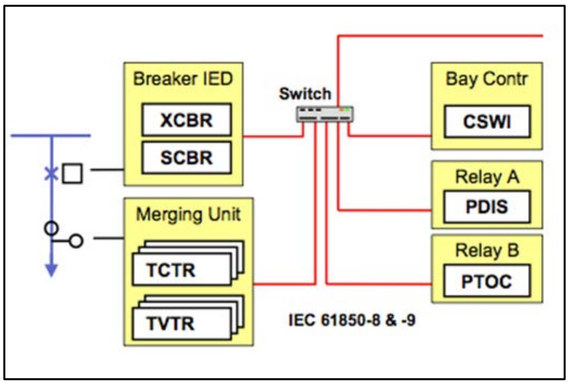

Figure 4.12 - Process close connection details of both non-conventional instrument transformers and intelligent circuit breakers resulting in a full process bus solution [12].

The last step in the process bus implementation comes with the introduction of intelligent switchgear like disconnect switches and circuit breakers with communication capabilities. A full process bus will be used to connect both merging units and breaker IEDs with the protection and control devices, guaranteeing the exchange of information between process and bay levels, Figure 4.12. At this point, a switched network compliant with the IEC 61850 standard should have replaced all conventional connections.

4.5.3 – Reliability and Redundancy

In conventional connected substations, the communication network for substation automation systems (SAS) uses proprietary serial links within bay units, and parallel cooper wiring from bay to process level. In some substations this communication network might be duplicated to achieve a higher degree of availability and reliability. The IEC 61850 standard includes directions on how to implement a complete redundant network for both station bus and process bus levels.

To start with, there are two basic methods to assure redundancy in substation automation networks, and thus achieve high quality communication standards [49]:

- Redundancy in the network: The network offers redundant links and switches, but nodes are individually attached to the switches through non-redundant links.
- Redundancy in the nodes: A node is attached to two different redundant networks of arbitrary topology by two ports.

In addition to that, IEC 61850 includes two redundancy protocols for the station bus as well as for the process bus, which can be used in substations of any size or topology [49]:

- Parallel Redundancy Protocol (PRP): Specifies that each device is connected in parallel to two local area networks of similar topology.
- High-availability Seamless Redundancy (HSR): Applies the PRP principle to rings and to rings of rings to achieve cost-effective redundancy; and for this, each device incorporates a switch element that forwards frames from port to port.

Finally, the timing requirements for the station and process buses are among the more important parameters when regarding redundancy in substation networks. For the station bus, tolerated delays are: 100 ms when carrying command information, and 4 ms when interlocking, or carrying trip and reverse blocking signals. However, since the process bus carries time-critical information data from the measuring units and to the protection switchgear, the maximum tolerated delays are 4 ms.

4.5.4 – Verification, Validation and Testing

The introduction of IEC 61850-based substation automation systems brings new challenges to the testing and commissioning of substations. Every system need to be tested, verified, and validated, to assure that it meets all communication, integration, functionality, security and performance pre-defined requirements.

However, since in the new architecture all wired connections have been replaced by logic links, there are no direct access points to simulate input and output signals. As a result, new software suites combining a set of analytical, diagnosis and simulation tools are needed.

The software suites are even more crucial during engineering phases and factory acceptance tests (FAT) since it is necessary to perform application tests even with some system components not physically available. Taking in account that, there are now simulation tools that when connected to the system bus or directly to an IED, can simulate the non-existing devices.

The simulation tools, initially loaded with the system configuration description (SCD) file of the substation automation system (SAS), can simulate one or more electronic devices/ field units, based on the interface description settings defined in the SCD file. Thanks to this, simulation tests on real system components can be performed ahead of the site implementation stage.

4.6 – Summary

Substation automation systems evolution went from electromagnetic to numerical relays at first, and followed with the implementation of digital communications at station level, but still subjected to proprietary protocols. Then the IEC 61850 was introduced, and interoperability between different devices became possible, but the next big step in the evolution of substation automation will come with the implementation of the process bus.

The process bus interconnects the protection and control devices at bay level, with the instrument transformers and switchgear equipment at process level. The main difference results from the replacement of conventional copper wires by fibre optic cables, and the transmission of current and voltage samples, as well as protection and command signals, over a serial link network, instead of parallel point-to-point connections. In the future, it should be possible to have a seemingly data exchange between station, bay and process levels, with all substation devices communicating over a single Ethernet network.

Among the various advantages of implementing such a process bus, is the massive reduction of secondary side cabling by going from many cooper wires to a few fibre optic cables, which results in reduced costs across project, commissioning, and maintenance [17]. But even more important is that, with electrical and process data from all substation readily available, new assets condition-monitoring systems can be also implemented.

Besides that, the process bus makes it possible to replace conventional electromagnetic instrument transformers by novel optical current/voltage sensors with increased advantages in cost, space, safety and quality of measurements. However, it needs to be said that, there are some technical issues as well, as for example the necessity of merging units and breaker IEDs to be used with the new sensors and actuators.

With a well-established electrical network in the country, the focus for the network operator will be more on refurnishing or extending existing installations than building new substations. Because of this it is important to realise that the upgrade to full process bus architecture is going to be continuously. Firstly the non-conventional instrument transformers will step forward and merging units will need to tag along. And just then, the intelligent switchgear devices will make their way through together with the breaker IEDs as obvious.

Finally, it needs not to be forgotten that despite all a process bus implementation needs to be carefully studied and analysed to a maximum detail since points like reliability, availability and redundancy need to be addressed during engineering phases. Additionally, forthcoming verification, validation and testing stages should be given proper importance since with wired connections replaced by logic links, a miss planned system is more prone to failures than conventionally connected legacy systems.

Chapter 5

Assets Condition Monitoring

This chapter provides an overview of techniques commonly available for transformer asset management. It starts by presenting the reader with the benefits of switching from Schedule Maintenance to Predictive Maintenance, and showing the role of Intelligent Electronic Devices in the Condition Monitoring and Protection of Power Transformers.

Following this, we will look at the Transformer Gas Analyser, a monitoring device for transformer diagnostics, which uses the Dissolved Gas Analysis technique, to evaluate the condition and protect transformers.

Meanwhile, the focus will change towards the Dissolved Gas Analysis, a technique for the interpretation of gases generated in oil-immersed transformers. We will see the types of incipient faults usually diagnosed in power transformers, and review four diagnosis methods used to detect these faults, i.e. Gas Levels, Key Gases, Gas Ratios, and the Duval's Triangle.

Finally, in the last section we introduce a simplified model to support the decision making process of whether to acquire a transformer gas analyser. The approach taken is based in the cost-benefit analysis, and evaluates both the probability of failure and the failure costs, to assess if the project of implementing a Transformer gas Analyser is a sound investment. The deferring replacement and overloading financial benefits are also forecasted.

5.1 – Transformer Protection & Maintenance

This section provides an overview of techniques commonly available for the protection, monitoring and maintenance of power transformers, and covers the three following topics: predictive maintenance, monitoring devices, and transformer management.

5.1.1 – Predictive Maintenance

Predictive maintenance is becoming extremely important in the efforts of utilities to deal with reduced personnel and at the same time increasing customer requirements for improved power quality and reliable supply of electric power [57]. Recent efforts are towards the research and development of improved techniques and enhanced solutions for condition monitoring of primary equipment with the purpose of switching from scheduled into event driven maintenance.

Utilities are also more aware of the benefits of, and willing to move from, Scheduled Maintenance periods to Predictive Maintenance periods, thanks to the evolution in numerical relaying technology. In fact, present day protective relays, as the Intelligent Electronic Devices, come with enhanced monitoring functions that allow utilities to evaluate the need for equipment maintenance based on user-defined alarm signals.

5.1.2 – Benefits of Monitoring Devices

The recent advances in monitoring techniques and hardware technology could be applied to improve existing monitoring schemes such as the transformer asset management, circuit breaker condition monitoring, and dynamic line rating systems [23]. In fact, protective relay manufacturers, in addition to new protection algorithms, are also paying increasing attention to the development of condition monitoring schemes for primary equipment.

Protection relays, provided with these improved features, are able to detect faults in the primary or secondary components of the overall protection system in a timely manner, thus allowing for event-driven maintenance instead of scheduled maintenance, which helps prevent system failures and reduce repair costs. All of the above shows that the availability of advanced monitoring functions gives the user valuable tools for improving the efficiency and reducing the cost of maintenance in the electric power system [57].

5.1.3 – Transformer Asset Management

Power transformers are generally the most valuable assets for every energy utility, and due to their high capital cost, as well as the need for their as high as possible in-service availability, they should be the main concern of condition monitoring and protection. As a matter of fact, as lifestyle expectations of consumers raise, and electric vehicle recharging loads become more common, the demand on the network increases, and transformers become more critical in order to assure that this demand is supplied. This thus increases the importance of knowing the health of the transformers in real-time, in order to allow for condition-based maintenance activities to be scheduled, since a timely planned maintenance or recondition is indeed far more preferable than a forced unplanned outage due to failure.

Loss of life monitoring

Ageing of transformer insulation is a time-dependent function of temperature, moisture, and oxygen content, but moisture and oxygen are reduced at the transformers' design stage by mounting protective devices, thus leaving temperature as the main parameter in insulation deterioration. Asset management systems are used to simulate the rate of deterioration, and the state of insulation of a given transformer, and do so applying real-time hot-spot temperature algorithms that take ambient temperature, top-oil temperature, load current flowing, as well as the status of oil pumps and radiator fans as inputs. Modern IEDs evaluate the current rate of life loss and in order to provide the remaining time until critical insulation levels, usually related with degradations in the tensile strength of the insulation and/or in the degree of polymerisation, are likely to be reached. This way, outages can be planned in advance, and investment decisions made ahead of time.

Through-fault monitoring

While loss of life monitoring serves to track the deterioration caused by long term, repeated overloading; through-fault monitoring is used to monitor short-term heavy fault currents which flow through the transformer, out to an external fault on the downstream power system [57]. Through faults are responsible for currents much larger than the rated current of the transformer, and therefore are a major cause of transformer damage and failure, as they stress the insulation and mechanical integrity, e.g. bracing of the windings [57]. Modern IEDs evaluate the heating effect of the maximum phase current and duration of the fault event every time a through current exceeds a pre-defined threshold. These results are added to cumulative values and made available for further analysis, hence allowing users to make better informed decisions regarding transformer maintenance and replacement.

5.2 – Transformer Monitoring & Diagnostics

Transformers are a vital part of the power transmission and distribution network, but they are also large and expensive assets, usually without spares readily available, and with a very long lead time for replacement. As result of this, monitoring and diagnostic technologies focused on electrical transformers are essential to power utilities, providing them with the means to monitor transformers, predict failures, and proactively manage their performance.

Transformers, like any other asset, have a finite life that can be shorten through abuse or prolonged with care by monitoring their condition and acting in a timely manner. By monitoring their condition it is possible to change from a time-based maintenance to condition based maintenance, and thus significantly reduce maintenance costs. In fact, most units serve for years without any problem, but an unexpended failure with forced outage can be very costly, and have catastrophic results such as personnel injuries and damage to other equipment. Continuous monitoring also allows utilities to continue using a transformer until a replacement solution if found, even if it has a terminal problem and is nearing end of life, thus keeping them in business.

Finally, the decision of what type of monitoring and diagnostic product or service to take for each transformer should be based on the following key decision factors: the cost and criticality of the asset, its known health status and history of use/abuse, the distance of access and availability of communications.

- Monitoring: by comparing the concentration of gases in oil with previous measures, one can detect small changes and developing trends before they become an issue but enough to indicate a possible impeding issue [55].
- Diagnostic: by noting which gases are increasing, we can determine the likely nature of the anomaly, and start being able to make decisions based on this information without having to shut down the transformer to determine what is happening [55].

5.2.1 – Transformer Gas Analyser

Accurate knowledge of the condition of transformers is essential for all electrical networks and on-line monitoring of critical transformers is becoming increasingly vital. This information allows valuable assets to be maximised and expensive failures to be avoided. Dissolved Gas Analysis (DGA) and moisture measurement of the insulation oil are recognised as the most important tests for condition assessment of transformers.

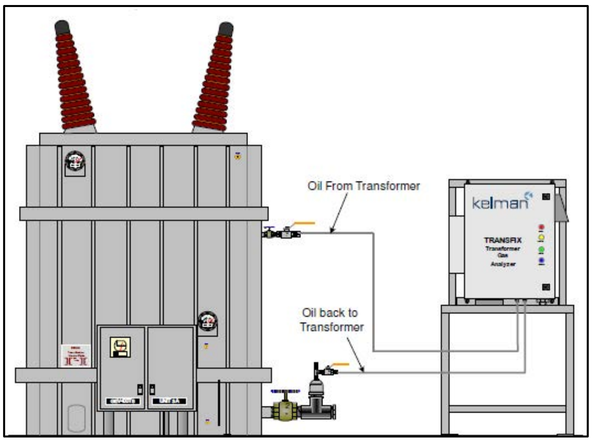

Figure 5.1 - Schematic Representation of a Transformer Gas Analyser Installation.

Transformer Gas Analysers are intelligent on-line monitoring systems used in transformer diagnostics that measures the level of dissolved combustible gases and moisture in the transformer insulating oil for the evaluation of dangerous conditions such as critical arcing, cellulose degradation, bubbling temperature, aging rate, and for the early detection of general faults. These equipment, provides reliable information and represents an invaluable tool for Asset Management, as they help avoid costly unplanned outages, detect transformer faults in their infancy, safely optimise transformer output, calculate transformer ageing, and classify type of faults from results.

Transformer Gas Analysers are equipped with a gas detector that is sensitive up to eight gases, which are the primary indicators of incipient faults in oil-filled electrical equipment, and with a moisture sensor that provides essentially the measurement of total water dissolved in the oil. The gas detector measures a composite value of the following dissolved gases in oil: Hydrogen, Methane, Ethane, Ethylene, Carbon Monoxide, Carbon Dioxide, Oxygen and Acetylene. These instruments, Figure 5.01, extract gas from the oil in the transformers, analyse it using either Photo Acoustic Spectroscopy (PAS) or Gas Chromatography (GC) techniques, and store the results making them available for downloading into a computer.

5.2.2 – Online Dissolved Gas Analysis

The Dissolved Gas Analysis provides an idea of the health of the transformer and is generally recognised as a key tool in determining a transformers condition, however, the traditional practice of taking a manual sample and sending it to lab for analysis is obsolete nowadays since aging of critical assets require continuous monitoring. Online DGA devices, automatically collect an oil sample from the transformer, extract the gas from the sample, measure the gas concentrations, both record and store this data internally, and finally return the oil to the transformer, repeating the process all over again at a customised frequency.

Up until now, this analysis has been carried out by Gas Chromatography (GC), but is being replaced by the Photo-Acoustic Infrared Spectroscopy (PAS), an alternate technique that is less prone to errors and produces more reliable results.

- Gas Chromatography (GC): is a chromatographic technique used to separate organic volatile components of a mixture. A gas chromatograph consists of a flowing mobile phase, an injection port, a separation column containing the stationary phase, a detector, and a data recording system. The organic compounds are separated due to differences in their partitioning behaviour between the mobile gas phase and the stationary phase in the column.
- Photo-Acoustic Infrared Spectroscopy (PAS): is a spectroscopy technique where the gas to be measured is irradiated by modulated light of a pre-selected wavelength, and as the gas molecules absorb some of the light energy it is converted it into an acoustic signal which is detected, Figure 5.02. The frequency of the light absorbed is a characteristic of each gas, and the amount of light absorbed is determined by its concentration. The gas gets heated and expands causing a pressure rise as it absorbs energy, and since the light is intermittent the pressure will fluctuate thus producing an acoustic signal ready to be processed.

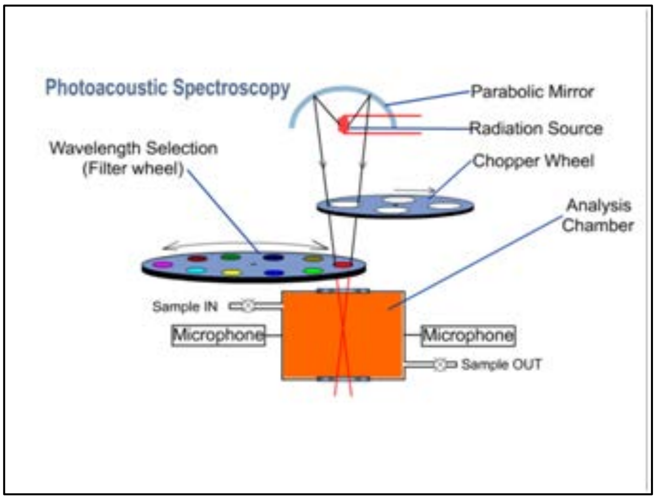

Figure 5.2 - Photo-Acoustic Infrared Spectroscopy [55].

5.3 – Dissolved Gas Analysis

According to the IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, there are four diagnosis methods that can be used with the dissolved gas analysis in order to detect incipient faults and evaluate the condition of a power transformer: Gas Levels method, Key Gases method, Gas Ratios method, and Duval's Triangle [25] and [26].

5.3.1 – Types of Faults

The types of incipient faults that can be found in a given power transformer, and are possible to be detected with these diagnosis methods, fall within the following categories: Partial Discharges (PD), Energy Discharges (D) and Thermal Faults (T).

- PD – partial discharges of the cold plasma (corona) type, resulting in possible wax deposition on paper insulation; or of the sparking type, inducing pinhole, carbonized perforations (punctures) in paper, but that may not be easy to find.
- D1 – low energy discharges in oil and/or paper, evidenced by larger carbonized perforations through paper (punctures), carbonization of the paper surface (tracking) or carbon particles in oil.
- D2 – high energy discharges in oil and/or paper, evidenced by extensive destruction and carbonization of paper, metal fusion at the discharge extremities, extensive carbonization in oil, and in some cases, tripping of the equipment.
- T1, T2, T3 – thermal faults in oil and/or paper, below 300°C if the paper has turned brownish (T1), above 300°C if it has carbonized (T2), and above 700°C if there is strong evidence of carbonization of the oil (T3) with metal coloration (800°C) or metal fusion (>1000°C).

5.3.2 – Gas Levels

The analysis and monitoring of critical combustible gases over time, as the Total Dissolved Combustible Gases (TDCG), Table 5.01, and later comparison with typical concentration values observed in power transformers, can be used to determine whether one of the following four fault conditions may be present [24].

Table 5.1 — Dissolved Key Gas Composition Limits (ppm).

	Hidrogen	Methan	Acetylene	Ethylene	Ethane	Car.Monoxide	Carbon Dioxide	Total Dissolved Combustible Gas
Condition 1	100	120	35	50	65	350	2500	720
Condition 2	101-700	121-400	36-50	51-100	66-100	351-570	2500-4000	721 – 1920
Condition 3	701-1800	401-1000	51-80	101-200	101-150	571-1400	4001-10000	1921 – 4630
Condition 4	>1800	>1000	>80	>200	Z150	>1400	>10000	> 4630

Condition 1 - TDCG below 720 ppm indicates that the transformer is operating satisfactorily, but any individual combustible gas exceeding specified levels should prompt additional investigation.

Condition 2 - TDCG between 721 ppm and 1920 ppm indicates greater than normal combustible gas level. Action should be taken to establish a trend and check gas generation rates since faults may be present.

Condition 3 - TDCG betwwen 1921 ppm and 4630 ppm indicates a high level of decomposition. Immediate action should be taken to establish a trend and check gas generation rates since faults are probably present.

Condition 4 - TDCG over 4630 ppm indicates excessive decomposition, and continued operation could result in failure of the transformer, so one should proceed immediately and with caution and resample and check gas generation rates.

5.3.3 – Key Gases

Another method of diagnosing faults in a power transformer is to determine the relative proportion of each gas, Table 5.02, and plot the obtained data into bar charts, and finally cross compare these against industry standard Key Gas diagrams of known gas concentration percentages.

Table 5.2 — Gases generated by transformer faults.

Hydrogen (H_2)	Mineral Oil Decomposition, Thermal faults, e.g. oil and cellulose, Partial Discharge, Arcing.
Carbon Monoxide (CO)	Cellulose Aging, Thermal faults, e.g. cellulose.
Acetylene (C_2H_2)	Mineral Oil Decomposition, Thermal faults 700+ºC, Arcing.
Water (H_2O)	Cellulose aging, Leaks in oil expansion systems/gaskets/welds.
Methane (CH_4)	Mineral Oil Decomposition, Thermal faults, e.g. oil and cellulose, Partial Discharge, Arcing.
Ethane (C_2H_6)	Mineral Oil Decomposition, Thermal faults 150-700ºC
Ethylene (C_2H_4)	Mineral Oil Decomposition, Thermal faults 300-700+ºC, Arcing.
Carbon Dioxide (CO_2)	Cellulose Aging, Thermal faults, e.g. cellulose, leaks in oil expansion systems/gaskets/welds.
Oxygen (O_2)	Thermal faults, e.g. cellulose, leaks in oil expansion systems/gaskets/welds.

5.3.4 – Gas Ratios

The ratios between some of the key gases can also be used to analyse and diagnose problems in power transformers [27]. The gas ratios method compares these values against default ratios defined in IEC and IEEE standards as the Basic Gas Ratios, Table 5.03, or Roger Ratios, Table 5.04.

Table 5.3 — Basic Gas Ratios used in Dissolved Gas Analysis.

	Acetylene / Ethylene	Methane / Hydrogen	Ethylene / Ethane
Partial Discharge	Non Significant	< 0.1	< 0.2
Low Energy Discharges	> 1.0	0.1 – 0.5	> 1.0
High Energy Discharges	0.6 – 2.5	0.1 – 1.0	> 2.0
Thermal Fault 300<T<500 °C	Non Significant	>1 but Non Significant	< 1.0
Thermal Fault T < 300 °C	< 0.1	> 1.0	1.0 – 4.0
Thermal Fault T > 500 °C	< 0.2	> 1.0	> 4.0

Table 5.4 — Roger Ratios used in Dissolved Gas Analysis.

	Acetylene / Ethylene	Methane / Hydrogen	Ethylene / Ethane
Normal	< 0.1	0.1 – 1.0	< 1.0
Partial / Low Energy Discharges	< 0.1	< 0.1	< 1.0
High Energy Discharges	0.1 – 3.0	0.1 – 1.0	> 3.0
Thermal Fault 300<T<500 °C	< 0.1	0.1 – 1.0	1.0 – 3.0
Thermal Fault T < 300 °C	< 0.1	> 1.0	1.0 – 3.0
Thermal Fault T > 500 °C	< 0.1	> 1.0	> 3.0

According to the IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, besides the two previous methods, the analysis of dissolved gasses in the transformer oil can also be done using the Doernenburg Ratios method.

5.3.5 – Duval's Triangle

The Duval Triangle uses three gases only, i.e. Methane, Ethylene and Acetylene, which correspond to the increasing levels of energy necessary to generate gases in transformers in service. The three sides of the Triangle are expressed in triangular coordinates representing the relative proportions of Methane, Ethylene and Acetylene. The zone in which the point falls in the Triangle allows identifying the fault responsible for the DGA results, Figure 5.03.

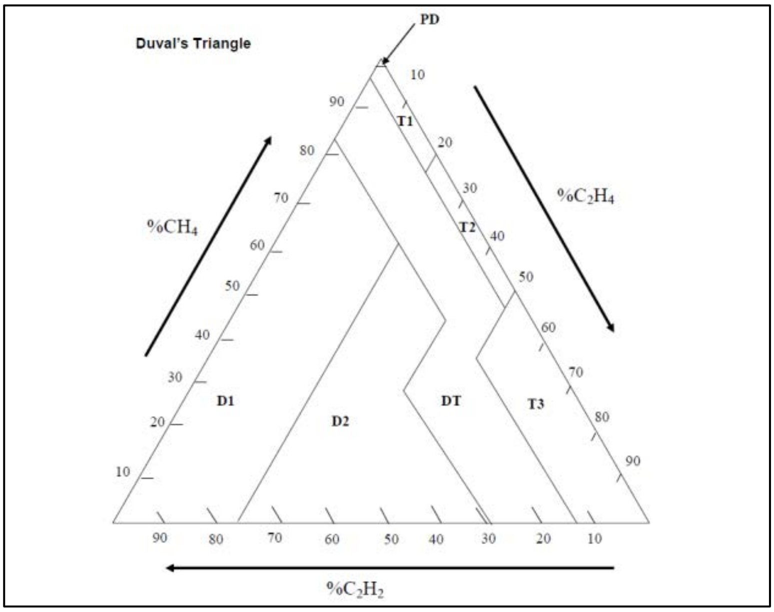

Figure 5.3 - Duval's Triangle method used in Dissolved Gas Analysis [55].

PD = Partial Discharges	T1 = Thermal fault T < 300°C	D1 = Low Energy Discharges
	T2 = Thermal fault 300<T<500°C	D2 = High Energy Discharges
	T3 = Thermal fault T > 500°C	DT = Discharge/Thermal Fault

5.4 – Economic Appraisal of Monitoring

This section is intended to present a simplified model to support the decision making process of whether to acquire a transformer gas analyser. It takes into account the costs and benefits denominated in monetary terms, in order to assure the project (Transformer Gas Analyser) achieves value for money and satisfies the requirements.

The cost-benefit analysis process, hereafter described, calculates and compares the benefits and costs of the project (Transformer Gas Analyser), with the purpose of determining whether it is a sound investment, comparing the total expected costs against the total expected benefits, to access if the latter outweigh the first, and by how much.

5.4.1 – Cost–Benefit Analysis

The most recognised benefit of online monitoring is the early detection of incipient faults, with the objective of preventing major failures and converting them into a repair job of less magnitude under a planned outage condition. This translates in both maintenance and repair cost savings with the transformer. Condition monitoring also helps utilities reduce the amount of energy not delivered, and extend transformers lifecycle, further improving its overloading capacity.

First, some of the faults can already be detected by existing systems as the Buchholz relay and periodic in-lab Dissolved Gas Analyses. Second, the detection rate of on-line monitoring is also not perfect and some instantaneous failures may go undetected. Finally, catastrophic failures, as tank ruptures and fire, should be treated separately due to its costly consequences. Given all these, the IEEE guide "application of monitoring to liquid-immersed transformers and components" states that:

Risk = Probability of Occurrence x Consequences of Event
Benefit = Risk Without Monitoring – Risk With Monitoring

5.4.2 – Probability of Failure

The cumulative probability of failure model for power transformers is based on the Weibull-distribution model, as seen in Equation (1.1).

$$Weibull(t,\alpha,\beta) = \frac{\alpha}{\beta}\left[\frac{t-t0}{\beta^{\alpha}}\right]^{\alpha-1} e^{\frac{(t-t0)^{\alpha}}{\beta}} \quad , \qquad (1.1)$$

where α is the transformer shape parameter, and β the Mean Time Between Fails (MTBF).

To simulate the probability density, reliability, hazard rate, and cumulative probability of failure for the common transformer of a given utility, it is then necessary to conduct a study based on the health history of the transformers in service, therefore ended up with the alpha and beta parameters for that transformer population.

Given that was not possible the results hereafter shown are based upon data retrieved from a General Electrics report and are based on data collected from a number of transformers in use at the electric network in the USA, Figure 5.04 and Figure 5.05.

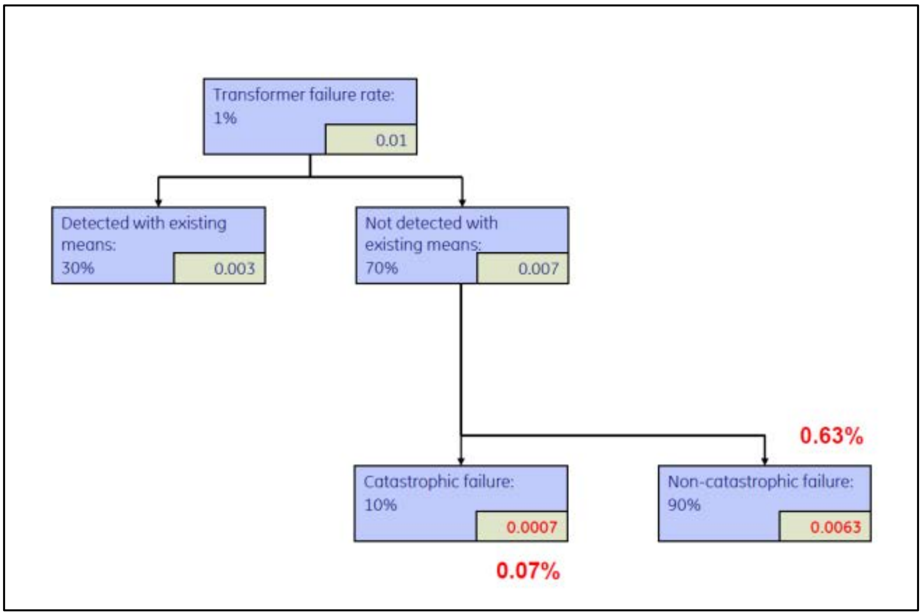

Figure 5.4 - Probability of Failure Indices without Transformer Monitoring [54].

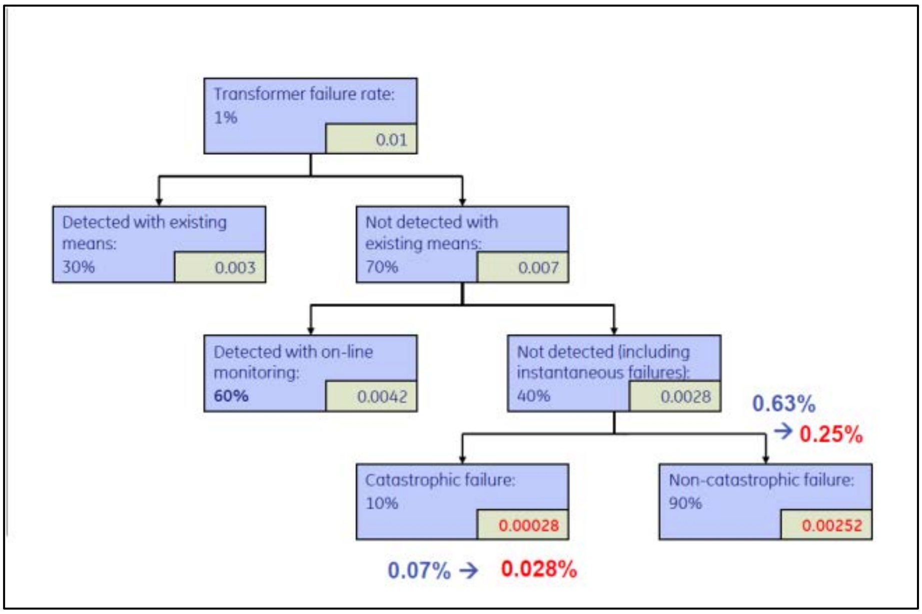

Figure 5.5 - Probability of Failure Indices with Transformer Monitoring [54].

5.4.3 – Failure Costs Evaluation

The failure costs were evaluated for two cases, a catastrophic failure where the transformer would have to be replaced by a new unit, and a major failure where the repair of the transformer would account for 60% of the price of a new unit.

Annualised Repair Costs without On-Line Monitoring			
Major Failure	€300,000 x 0.0063	=	€1890
Catastrophic Failure	€500,000 x 0.0007	=	€350
Total annualised repair cost without monitoring:			*€2,240*
Annualised Repair Costs with On-Line Monitoring			
Major Failure	€300,000 x 0.00252	=	€756
Catastrophic Failure	€500,000 x 0.00028	=	€140
Early Detection Repair	€40,000 x 0.0042	=	€168
Total annualised repair cost with monitoring:			*€1,064*
Annual Benefit of Monitoring on Asset Failure Resolution Costs:			
	€2,240 - €1,064	=	€1,176

A study conducted by *Hartford Steam Boiler Inspection*, showed that the average consequential damage cost of a transformer failure is about €300,000 over a 5 year period. According to the same insurance company, considering the rated power of transformers, the property damage portion is about €9,000 / MVA.

5.4.4 – Deferring Replacement

Deferring the transformer replacement can drive huge economic benefits to the owner by delaying investment, but it also bears high risks associated with the increasing risk of failure linked with the age of the unit.

However, if a detection level of 50% is assumed, the risk of failure is reduced proportionally, Figure 5.06, and the unit can remain in service until the failure risk/or maximum allowable load rises again to an unacceptable level [54].

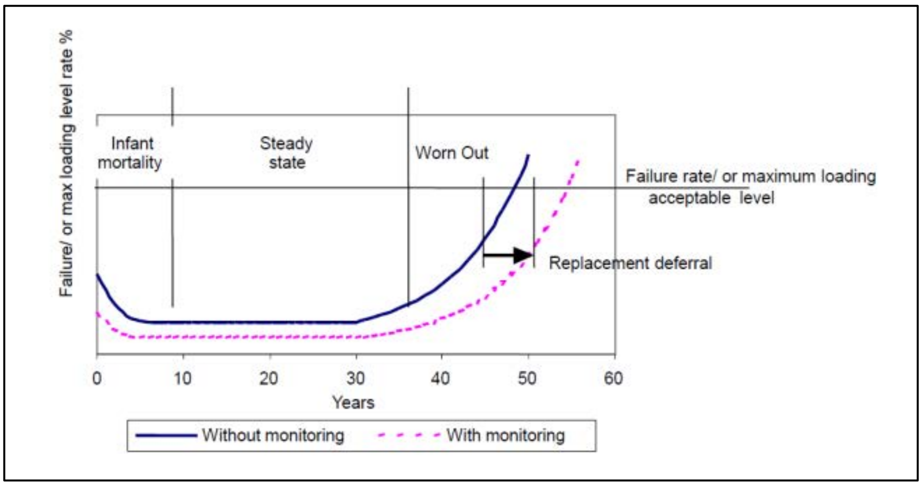

Figure 5.6 - Deferring Transformer replacement [54].

The benefit from deferring replacement is directly proportional to the current interest rate and the capital cost of a new unit.

Benefit from Deferring Transformer Replacement	
Replacement Cost of Transformer	€500,000
Annual Interest Rate	6%
Benefit from deferring replacement	*€30,000*

Monitoring Benefit:
€30,000 /Extra year of service / Transformer

5.4.5 – Overloading Benefits

The delivery of additional power under emergency conditions can lead to large profit margin for the company, but it bears some risks, and has as main consequence for long duration overload the thermal aging of solid insulation. It is possible, though, to monitor the excessive overheating of leads, shields, structural parts, contacts or bolted joints; as well as the moisture in paper and the hot spot temperature to allow for closer control of the transformers' health status.

Annualised benefits of overloading – Without monitoring		
Gross profit on extra energy delivered:		
3MW x 100 hours x €60/MWh x 0.2	=	€3,600
Value of additional loss of life to transformer:		
€500,000 / 150,000 hrs x 100 hrs x (2.7 - 1) x 0.2	=	(€113)
Total annual benefits of overloading without monitoring:		*€3,487*
Annualised benefits of overloading – With monitoring		
Gross profit on extra energy delivered:		
6MW x 100 hours x €60/MWh x 0.2	=	€7,200
Value of additional loss of life to transformer:		
€500,000 / 150,000 hrs x 100 hrs x (11 - 1) x 0.2=		(€667)
Total annual benefits of overloading with monitoring:		*€6,533*
Annual Benefit of Monitoring on Increased Loading Capacity:		
€6,533 - €3,487	=	€3,046

To forecast the annual benefits of transformer monitoring on increased loading capacity, as seen above, it was assumed a price tag of €500,000 for a new 30MVA power transformer, and 60% repair costs in case of non-catastrophic failure. In addition, it was considered that, the transformer has a 20% overloading capacity when on monitoring and 10% when without it, as well as, an ageing acceleration factor of 11 in the former and 2.7 in the latter case. Moreover, in both cases the probability of overload was set to 20%, and the duration of overloading defined as 100 hours per year. Furthermore, the transformer lifetime was estimated as roughly 150,000 hours, and the profit margin of delivered energy as 60 euros per MW hour.

Annual Benefits of Transformer Monitoring	
Asset Failure Resolution Costs:	€1,176
Deferring Transf Replacement:	€30,000
Increased Loading Capacity:	€3,046
Total Benefits	€34,222

In order to accurately estimate the total benefits on transformer monitoring, it is necessary to sum the annual benefits from asset failure resolution, from deferring transformer replacement, and from increased loading capacity, ended up with €34,222 on forecasted savings per year, for a €500,000 power transformer, as seen above.

5.5 – Summary

Predictive maintenance is becoming extremely important in the efforts of utilities to deal with reduced personnel and increasing customer requirements for improved power quality and reliable power supply. At the same time, advanced monitoring functions provide utilities with the means to switch from Scheduled to Predictive maintenance, thus improving the efficiency and reducing the cost of maintenance in the electric power system.

Power Transformers are the most important equipment and expensive asset in a distribution substation. In addition, any transformer replacement is a difficult and time-consuming task as they bear high costs of procurement, transportation, and installation, along with long lead times. For all these, monitoring is essential to provide efficient maintenance and optimal use of their operational capacities.

Transformer Gas Analysers are intelligent on-line monitoring systems used in transformer diagnostics that measures the level of dissolved combustible gases and moisture in the transformer insulating oil for the evaluation of dangerous conditions, and for the early detection of general faults, thus lowering maintenance costs, extending transformer useful life, and avoiding expensive unplanned failures and costly unplanned outages.

Dissolved Gas Analysis (DGA) and moisture measurement of the insulation oil are generally recognised as the most important tests for condition assessment of transformers. These technique measures a composite value of eight dissolved gases in oil, which are the primary indicators of incipient faults in oil-filled electrical equipment. The gas extracted from the oil in the transformers is analysed using either Photo Acoustic Spectroscopy (PAS) or Gas Chromatography (GC) techniques.

According to the IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, there are four diagnosis methods that can be used with the dissolved gas analysis in order to detect incipient faults and evaluate the condition of a power transformer, i.e. Gas Levels, Key Gases, Gas Ratios, and the Duval's Triangle.

The simplified model introduced for the economic appraisal of the monitoring device, serves as a tool to support the decision making process of whether to acquire, or not, a transformer gas analyser. The approach is based in the cost-benefit analysis process, and evaluates both the probability of failure and the failure costs, to assess if the implementation of a Transformer Gas Analyser is a sound investment. The model evaluates as well the deferring replacement and capacity overloading financial benefits.

Chapter 6

Conclusions

6.1 – Analysis & Discussion

The Smart Grid concept has a key strategic role within the electricity networks of the future and according to the European Union's energy framework it should address the following eight priority areas: wide-area situational awareness, demand response and consumer energy efficiency, energy storage, electric transportation, cyber security, network communications, advanced metering infrastructure, and distribution grid management.

The smart substation concept is built on state of the art automation technologies for substations, and should enable a more reliable and efficient protection, monitoring, control, operation, and maintenance of the equipment and apparatus installed within the substations, as well as rapidly respond to system faults and provide increased operator safety. Smart substations shall then support the following four major characteristics: digitalisation, autonomy, coordination, and self-healing.

Electromechanical relays are still the primary source of protection due to its replacement cost and complexity, but are being replaced with solid-state relays, which have a higher level of performance and more sophisticated characteristics. The Intelligent Electronic Devices, started to replace existing relays, mainly because of their communication capabilities, and ability to both self-diagnose and self-adapt in real-time to variable system conditions.

Local area networks for substations have demanding capacity, performance, coverage, security, reliability, accuracy, and availability requirements that must be respected, but in order to enable remote supervision and control, a highly reliable, scalable, secure, robust and cost-effective communication network between substations and a remote control centres must also exist.

The introduction of the IEC 61850 standard for communication networks and automation systems in electric substations followed the need for a more platform-independent and interoperable protocol. The standard was proposed as a future-proof communication protocol capable of providing interoperability in a multi-vendor environment as well as an effective data sharing among different substation automation applications.

Electrical Substations are installations used for the transmission and distribution of electrical energy. Their main purpose is to transfer and transform the electrical energy by stepping-up or stepping-down the voltage. A standard installation has power transformers, switching equipment and instrument transformers, as well as the substation automation systems for protection, monitoring and control.

The high voltage equipment and the medium voltage auxiliary systems are located in the substation yard, whilst the rest of the medium voltage equipment, together with the relaying, metering, and control devices, are placed inside the control house. The central control unit, the human-machine interface, and the communications equipment is also installed within the control house but mounted on a different cabinet.

The substation automation systems are responsible for the protection, monitoring and control of all electric process within an electric substation. Both the system architecture and its organizational structure make the system reliable, flexible, modular and simple to expand.

The architecture of the substation automation systems can be mapped into a three levels hierarchical model with a process level, a bay level, and a station level. The process level consists of all HV/MV switchgear as well as instrument transformers. The bay level comprises all protection, monitoring and control devices. The local control centre, the human machine interface, and the engineering station compose the station level.

The communication between process level and bay level devices is established over several point-to-point links and uses copper wires as the physical transmission medium. The communications within the intelligent electronic devices, and between them and the local control centre, relies on a local area network implemented over fibre optic cables. The substation automation systems should also guarantee that all data is made readily available to the remote control centre.

Substation automation systems evolution went from electromagnetic to numerical relays at first, and followed with the implementation of digital communications at station level, but still subjected to proprietary protocols. Then the IEC 61850 was introduced, and interoperability between different devices became possible, but the next big step in the evolution of substation automation will come with the implementation of the process bus.

The process bus interconnects the protection and control devices at bay level, with the instrument transformers and switchgear equipment at process level. The main difference results from the replacement of conventional copper wires by fibre optic cables, and the transmission of current and voltage samples, as well as protection and command signals, over a serial link network, instead of parallel point-to-point connections.

The process bus makes it possible to replace conventional electromagnetic instrument transformers by novel optical current/voltage sensors with increased advantages in cost, space, safety and quality of measurements. However, there are some technical issues as well, as for example the necessity of merging units and breaker IEDs to be used with the new sensors and actuators.

Other advantage of implementing such a process bus, is the massive reduction of secondary side cabling by going from many cooper wires to a few fibre optic cables, which results in reduced costs across project, commissioning, and maintenance. But even more important is that, with electrical and process data from all substation readily available, new assets condition-monitoring systems can be also implemented.

Predictive maintenance is becoming extremely important in the efforts of utilities to deal with reduced personnel and increasing customer requirements for improved power quality and reliable power supply. At the same time, advanced monitoring functions provide utilities with the means to switch from Scheduled to Predictive maintenance, thus improving the efficiency and reducing the cost of maintenance in the electric power system.

Power Transformers are the most important equipment and expensive asset in a distribution substation. In addition, any transformer replacement is a difficult and time-consuming task as they bear high costs of procurement, transportation, and installation, along with long lead times. For all these, monitoring is essential to provide efficient maintenance and optimal use of their operational capacities.

Transformer Gas Analysers are on-line monitoring devices used in transformer diagnostics that measures the level of dissolved combustible gases and moisture in the transformer insulating oil for the evaluation of dangerous conditions, and for the early detection of general faults, thus lowering maintenance costs, extending transformer useful life, and avoiding expensive unplanned failures and costly unplanned outages.

Dissolved Gas Analysis (DGA) and moisture measurement of the insulation oil are generally recognised as the most important tests to evaluate the condition of transformers. This technique measures a composite value of eight dissolved gases that are the primary indicators of incipient faults. The gas extracted from the oil in the transformers can be analysed using the following diagnosis methods: Gas Levels, Key Gases, Gas Ratios, and the Duval's Triangle.

6.2 – Future Work

The simplified model introduced for the economic appraisal of the monitoring device, serves as a tool to support the decision making process of whether to acquire, or not, a transformer gas analyser. The approach is based in the cost-benefit analysis process, and evaluates both the probability of failure and the failure costs, to assess if the implementation of a Transformer Gas Analyser is a sound investment. The model evaluates as well the deferring replacement and capacity overloading financial benefits.

The analysis conducted was only intended to provide an overview on the operational and financial benefits possible to achieve through online monitoring. In fact the model developed is very basic in all its aspects. In order to have a more solid view of the project, it would be necessary to take in account more advanced concepts. Such economic concepts include the Weibull distribution model, the time value of money, and a sensitivity analysis. Regarding operation and maintenance issues, inputs as the transformer condition and overloading factors, as well as, failure direct and indirect costs, would also need to be considered.

As a matter of fact, the investment decision should be made upon evaluation of the Internal Rate of Return (IRR) and Net Present Value (NPV) of the project, and the Weighted Average Cost of Capital of the company. In order to be a sound investment it should go as follows:

$$IRR > WACC$$
$$NPV > 0$$
$$IRR / WACC >> 1$$

The construction of this financial model would prove very valuable to the network operator of Portugal in helping this utility make better informed decisions regarding the evaluation of future investments, and therefore goes as my final recommendation for future work.

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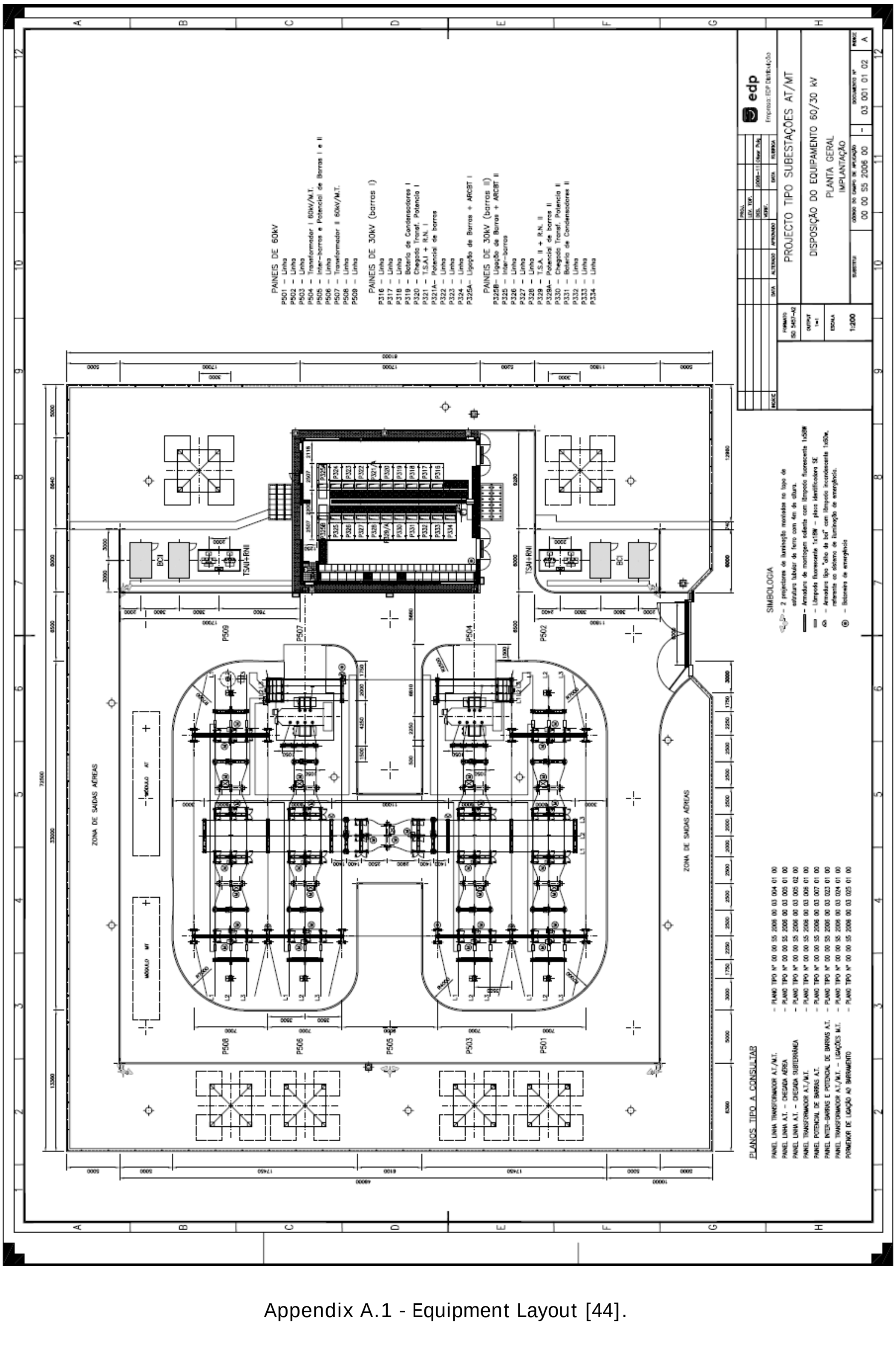
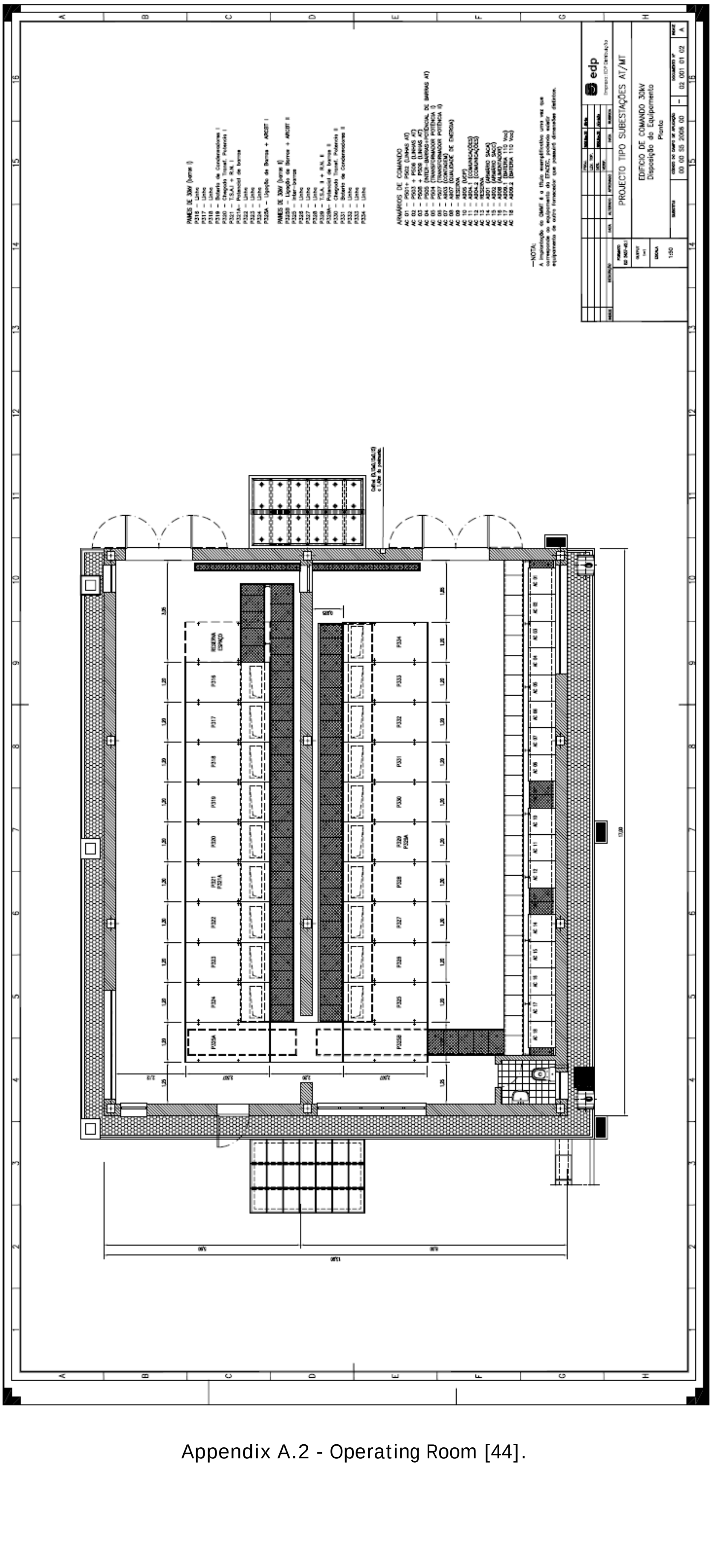
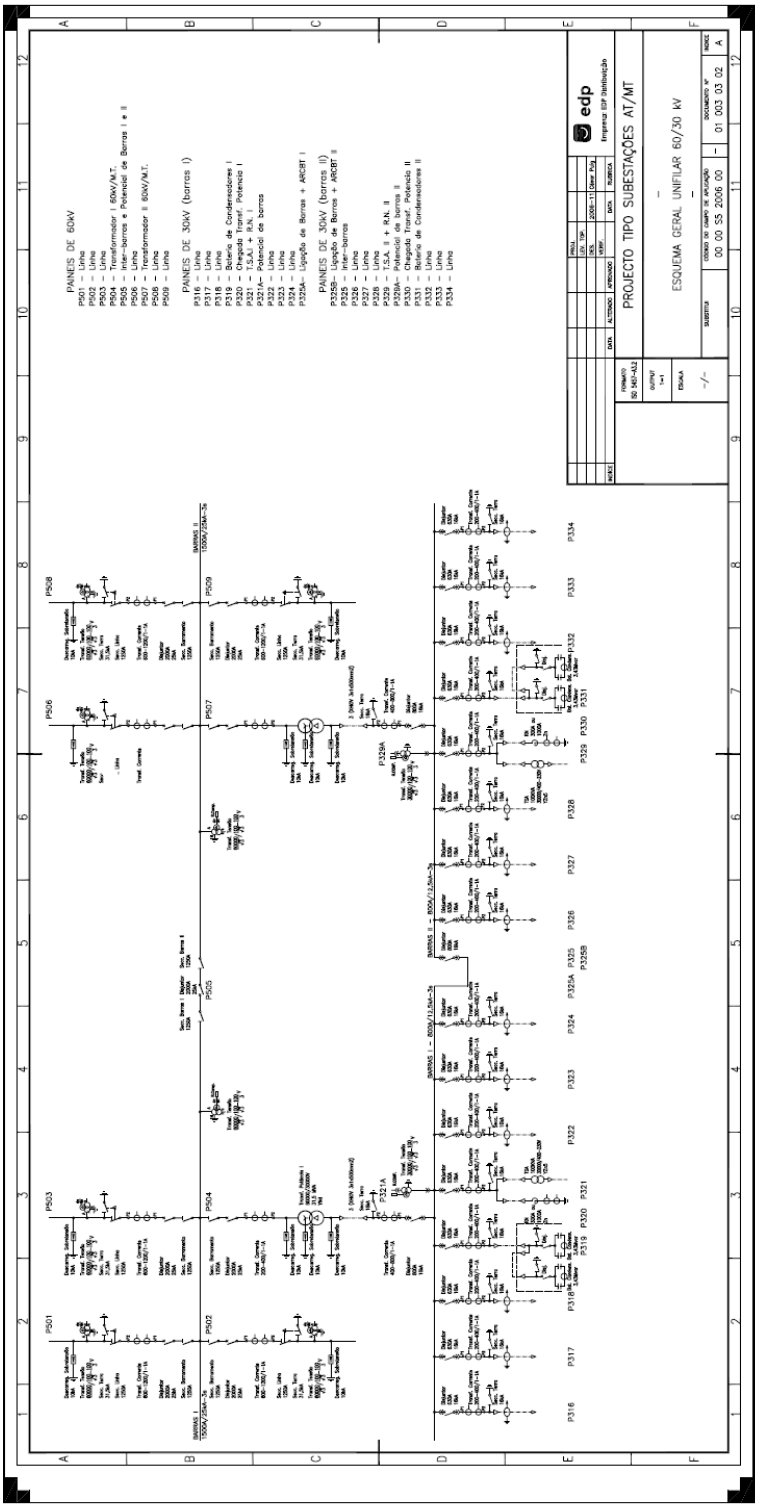
Appendix



Appendix A.1 - Equipment Layout [44].



Appendix A.2 - Operating Room [44].



Appendix A.3 - One-Line Diagram [44].