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COORDINATED AND OPTIMIZED VOLTAGE MANAGEMENT OF DISTRIBUTION NETWORKS WITH MULTI-MICROGRIDS

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Abstract

This thesis presents a set of proposals for advanced control functionalities in order to achieve a coordinated and optimized voltage management of distribution networks comprising several Distributed Generation units, controllable loads, storage devices and microgrids.

The approach followed here is based on the exploitation and extension of the microgrid concept following a massive integration of these “active cells” in electrical distribution networks. Therefore, a hierarchical control architecture is proposed in order to manage all these Distributed Energy Resources located in the distribution system in a coordinated way, based on advanced communication solutions exploiting a smart metering infrastructure. This control structure is characterized by the inclusion of an additional controller at the Medium Voltage level – the Central Autonomous Management Controller – leading to the development of the Multi-Microgrid concept.

Large scale integration of Distributed Energy Resources, namely Distributed Generation at the Medium Voltage level and microgeneration at the Low Voltage level, poses several technical challenges for distribution network operation, especially concerning voltage control. Accordingly, the development of specific control solutions is required in order to maximize the integration of these units in the distribution system.

Consequently, the work presented in this thesis focused on the development of a conceptual framework model for regional ancillary services markets for voltage control. The approach developed is able to integrate the reactive power bids from the several providers (namely Distributed Generation units or microgrids) in order to satisfy the requested reactive power needs at the Medium Voltage level, which are set by the Distribution System Operator. The market settlement is achieved based on cost minimization for the Distribution System Operator from purchasing reactive power. An ancillary services market simulator for reactive power use was developed implementing this approach for a medium-term time horizon using data from generation scheduling and renewable generation and load forecasts.

Finally, a methodology for voltage and reactive power control to be integrated in a tool for managing network operation in the short-term time-horizon has also been developed. This approach was developed in order to ensure a coordinated operation concerning the Medium Voltage and Low Voltage levels, by managing the several resources available such as Distributed Generation units, microgrids, controllable loads, On-Line Tap Changing transformers and other reactive power compensation devices. A meta-heuristic approach is used in order to optimize operating conditions. An Artificial Neural Network model has also been developed in order to replace “active” Low Voltage networks in the optimization module, making it suitable for online use in a real-time management environment.

Resumo

Nesta tese apresenta-se um conjunto de propostas com vista ao desenvolvimento de funcionalidades avançadas de controlo de forma a garantir uma gestão coordenada e optimizada de redes de distribuição de energia eléctrica incluindo diversas unidades de Produção Distribuída, cargas controláveis, dispositivos de armazenamento de energia e micro-redes.

A abordagem seguida baseia-se na exploração e extensão do conceito de micro-rede na sequência de uma integração maciça destas "células activas" nas redes de distribuição. Neste sentido, propõe-se o estabelecimento de uma arquitectura hierárquica de controlo capaz de gerir todos estes recursos distribuídos localizados no sistema de distribuição de uma forma coordenada, com base em soluções avançadas de comunicação que exploram uma infra-estrutura para tele-contagem de energia eléctrica. Esta estrutura de controlo é caracterizada pela inclusão de um controlador adicional ao nível da Média Tensão – o Controlador Central Autónomo de Gestão – que levou ao desenvolvimento do conceito de multi micro-rede.

A integração em larga escala de recursos distribuídos, nomeadamente Produção Distribuída ao nível da Média Tensão e micro-geração ao nível da Baixa Tensão, levanta diversos desafios técnicos para a operação da rede de distribuição, especialmente relativo ao controlo de tensão. Desta forma, torna-se necessário desenvolver soluções específicas de controlo de forma a maximizar a integração destas unidades no sistema de distribuição.

Consequentemente, o trabalho apresentado nesta tese foca-se no desenvolvimento de um modelo conceptual para a implementação de mercados regionais de serviços de sistema para controlo de tensão. A abordagem desenvolvida permite integrar as propostas de energia reactiva dos vários fornecedores (nomeadamente unidades de Produção Distribuída e micro-redes) de forma a satisfazer os requisitos de energia reactiva ao nível da Média Tensão, fixados pelo Operador do Sistema de Distribuição. O fecho do mercado é atingido baseado na minimização dos custos de compra desta energia para o Operador de Sistema. Baseado nesta abordagem, foi desenvolvido um simulador de mercado de serviços de sistema para controlo de tensão para um horizonte temporal de médio-prazo, utilizando informação proveniente do despacho de geração e de ferramentas de previsão de carga e de produção de recursos renováveis.

Desenvolveu-se ainda uma metodologia para o controlo de tensão e potência reactiva destinada a ser integrada numa ferramenta para um horizonte temporal de curto-prazo para ajuda à operação da rede. Esta metodologia foi desenvolvida de forma a garantir um controlo coordenado ao nível da Média Tensão e da Baixa Tensão através da gestão dos vários recursos disponíveis tais como unidades de Produção Distribuída, micro-redes, cargas controláveis, transformadores com regulação em carga e outros dispositivos de compensação de energia reactiva. A abordagem desenvolvida baseou-se na utilização de uma meta-heurística de forma a optimizar as condições de operação. Adicionalmente, foi desenvolvido um modelo de uma Rede Neuronal capaz de emular o comportamento em regime estacionário de redes "activas" de Baixa Tensão, modelo esse que foi integrado no módulo de optimização de forma a permitir a sua utilização em ambiente de operação em tempo-real.

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List of Acronyms and Abbreviations

AC – Alternate Current

AGC – Automatic Generation Control

ANN – Artificial Neural Network

AVR – Automatic Voltage Regulator

CAMC – Central Autonomous Management Controller

CCGT – Combined Cycle Gas Turbines

CERTS – Consortium for Electric Reliability Technology Solutions

CHP – Combined Heat and Power

CIGRE – International Council on Large Electric Systems

CIRED – International Conference on Electricity Distribution

CO_2 – Carbon Dioxide

DC – Direct Current

DER – Distributed Energy Resources

DFIG – Doubly-Fed Induction Generation

DG – Distributed Generation

DMS – Distribution Management System

DSM – Demand Side Management

DSO – Distribution System Operator

EC – European Commission

ENTSO-E – European Network of Transmission System Operators for Electricity

EPSO – Evolutionary Particle Swarm Optimization

ES – Evolutionary Strategies

ETS – Emission Trading System

EU – European Union

EURELECTRIC – Union of the Electricity Industry

GHG – Green House Gases

HV – High Voltage

ICT – Information and Communication Technology

IEA – International Energy Agency

IEE – Institution of Electrical Engineers

IET – Institution of Engineering and Technology

IG – Induction Generator

LC – Load Controller

LV – Low Voltage

MAS – Multi-Agent Systems

MC – Microsource Controller

MGCC – MicroGrid Central Controller

MPPT – Maximum Power Point Tracker

MSE – Mean Squared Error

MV – Medium Voltage

NERC – North American Electric Reliability Council

OECD – Organisation for Economic Co-operation and Development

OLTC – On-Line Tap Changing

OPF – Optimal Power Flow

PCC – Point of Common Coupling

PLC – Power Line Carrier

PSO – Particle Swarm Optimization

PV – PhotoVoltaic

PWM – Pulse-Width Modulation

RES – Renewable Energy Sources

RTU – Remote Terminal Unit

SG – Synchronous Generator

SO – System Operator

SQP – Sequential Quadratic Programming

STATCOM – Static Synchronous Compensator

SVC – Static var Compensator

T&D – Transmission and Distribution

toe – tonne of oil equivalent

TSO – Transmission System Operator

UCTE – Union for the Co-ordination of Transmission of Electricity

UNFCCC – United Nations Framework Convention on Climate Change

USA – United States of America

V2G – Vehicle-to-Grid

var – volt-ampere reactive

VSI – Voltage Source Inverter

"Rem tene, verba sequentur*: grasp the subject, and the words will follow. This, I believe, is the opposite of what happens with poetry, which is more a case of* verba tene, res sequenter*: grasp the words, and the subject will follow.*"

In the Postscript to "The Name of the Rose" by Umberto Eco (b. 1932)

Chapter 1 – Introduction

1.1 Motivation for the Thesis

Electrical power systems have been undergoing significant changes in the last few years. It is foreseen that these changes will mark an evolution of concepts and practices for the whole power system industry in a near future, especially concerning planning and operational procedures.

The traditional organization of power systems dated from the 1950s, based on large central generation units that supply electrical power through a transmission network to reach end-consumers in the distribution system, is beginning to be outdated. These large central generators are predominantly hydro power plants, fossil fuel-based power plants and nuclear power plants and in most of the countries there is a large dependency on imported fuels (mostly fossil fuels) since they do not have endogenous resources to fill their needs. According to [1], in Europe (27 countries), import dependency in 2007 was 82,6% for oil, 60,3% for gas and 41,2% for solid fuels. Moreover, according to the Organisation for Economic Co-operation and Development [1] and Eurostat[2], the gross inland consumption in Europe (27 countries) has grown from 1662 Mtoe[3] in 1990 to 1806 Mtoe in 2007 (more than 8%) while in the whole world the consumption has grown from 8462 Mtoe in 1990 to 12029 Mtoe (corresponding to an increase of over 42%).

Given the import dependency and the expected increase in energy consumption worldwide, especially considering the fantastic growth of China in recent years, the alleged scarcity of primary energy resources such as oil or gas is worrying the international community. The fear of possible shortcomings in energy supply is already affecting economic growth by raising energy prices from fossil fuels, and this is driving global policy-makers to define ambitious policies in order to address these issues.

[1] The Organisation for Economic Co-operation and Development (OECD) is an international economic organization of 31 countries that defines itself as a forum of countries committed to democracy and the market economy, providing a setting to compare policy experiences, seeking answers to common problems, identifying good practices, and coordinating domestic and international policies of its members.
For more information see http://www.oecd.org/

[2] Eurostat is the statistical office of the European Union situated in Luxembourg. Its task is to provide the European Union with statistics at European level that enable comparisons between countries and regions.
For more information see http://epp.eurostat.ec.europa.eu/portal/page/portal/eurostat/home/

[3] The tonne of oil equivalent (toe) is a unit of energy corresponding to the amount of energy released by burning one tonne of crude oil, which is approximately equal to 42 GJ.

On the other hand, a growing awareness of the environmental impacts from human activity is occurring, especially related to the exploitation of natural resources. In fact, the effect of human activity in the alleged climate change phenomenon is a matter of extreme concern in the present day. It is currently accepted that some of the so-called conventional technologies have serious environmental implications, namely high levels of Green House Gases (GHG) emissions (in the case of fossil fuels) or hazardous waste materials (in the case of nuclear energy). In particular, the emissions of Carbon Dioxide (CO_2) from the use of fossil fuels are now being severely restricted. It was found that CO_2 emissions have grown from 15640 million tonnes in 1973 to 28962 million tonnes in 2007 [2].

The negative aspects of fossil energy sources, coupled with the need for diversifying the generation mix, have pushed forward the development of the exploitation of Renewable Energy Sources (RES), such as wind or solar energy. Resorting to the exploitation of RES is seen as the most sustainable option to cope with growing demand for energy and particularly for electricity.

According to [1], in Europe (27 countries), the total share of RES in relation to the gross electricity consumption was of 15,6% by 2007. Figure 1-1 illustrates the growth of gross electricity generation from RES in Europe (27 countries) in recent years.

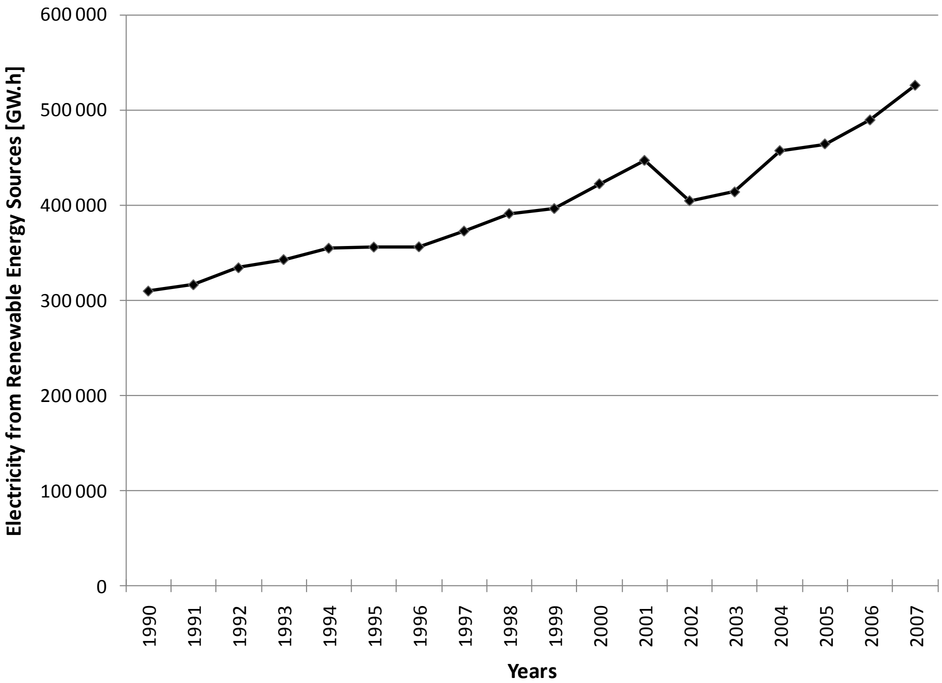

Figure 1-1 – Electricity Generation from Renewable Sources in Europe

Consequently, a change in paradigm is already occurring and must be pursued in order to be able to tackle effectively the new challenges that face us in the present and that will shape our future.

The European Commission has developed a strategy for addressing these challenges, namely on the subject of global warming (allegedly due the emission of GHG) and on the need for more secure energy sources *i.e.* less dependent on imports of foreign oil and natural gas. The

European Union's Climate and Energy Policy[4] sets the following targets for 2020, which were considered very ambitious given the current situation in most European countries [3]:

- Reducing GHG by at least 20% in relation to the 1990 levels;
- Increasing use of RES (such as wind, solar, biomass, *etc.*) to 20% of total energy generation;
- Reducing energy consumption by 20% of projected 2020 levels (by improving energy efficiency).

The deployment of Distributed Generation (DG) units, connected to the electrical distribution system, appears as a means of exploiting geographically disperse RES in order to help in achieving the goals that were set. These resources are based on technologies with zero direct GHG emissions such as wind, solar, biomass, *etc.* that can be used to generate power locally, *i.e.* near the customer site.

Furthermore, the connection of small DG sources directly to the Low Voltage (LV) level of distribution networks – microgeneration[5] – is also expected to grow rapidly in a near future, thus creating autonomous active cells called microgrids. A microgrid can be defined as an LV feeder with several microsources (such as microturbines, micro wind generators, photovoltaic panels, *etc.*) together with storage devices and controllable loads connected on that same feeder and managed by a hierarchical control system. These LV microgrids may be operated either in interconnected or islanded mode, under emergency conditions [4].

The new operation paradigm in electrical power systems involves a growing penetration of microgeneration in LV networks based on the development and extension of the microgrid concept. The massive integration of microgrids and DG units connected to the Medium Voltage (MV) level, and consequent need for coordinated management of these units, lead to the development of the **multi-microgrid concept**. This requires a higher-level structure, formed at the MV level, consisting of LV microgrids and DG units connected on several adjacent MV feeders. For the purpose of control and management, microgrids, DG units and MV-connected loads under Demand Side Management (DSM) control can be considered as active cells in this new type of system. The development of this concept poses challenging problems due to the increase in network dimension and operation complexity, since a large number of LV microsources and loads need to be operated together in a coordinated way.

In addition, it will be necessary to integrate these microgrids with existing DG units, directly connected into the MV network, as well as some large MV equivalent loads that may be under a DSM operation or load curtailment strategy for providing ancillary services. This involves the adaptation and development of new Distribution Management System (DMS) tools to be able to deal with such a demanding operating scenario. Consequently, the expansion and massive deployment of the microgrid concept should be based on the adoption of a three-level hierarchical control structure:

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[4] For more information see http://ec.europa.eu/energy/index_en.htm

[5] Throughout this thesis the term DG will be applied only to generation sources connected directly to the Medium Voltage (MV) or High Voltage (HV) levels of the distribution system, whereas the term microgeneration will be used for referring to sources that connect only at the LV level.

a) High Voltage (HV) and MV distribution network managed by a DMS;

b) MV network managed by a Central Autonomous Management Controller (CAMC), that is responsible for managing several microgrids together with DG units directly connected to MV feeders;

c) LV network managed and controlled by a MicroGrid Central Controller (MGCC).

Usually, DG connection to the distribution system is managed on the basis of a “fit-and-forget” philosophy, in which DG is regarded as a mere passive element of the system. Although this philosophy works for relatively moderate penetration of this type of sources, when considering high penetration levels there is a considerable impact on the distribution system. The main technical impacts resulting from large scale DG integration are mostly related to the voltage rise effect, power quality issues, branch overload problems, protection issues and stability issues [5].

In this context, and especially considering not only the recent but also the expected growth in DG and microgeneration integration levels, the fundamental question that this thesis tries to answer is:

What are the possible solutions to cope with the technical problems resulting from large scale DG and microgeneration integration?

The answer to this question is not straightforward. Considering relatively low levels of DG and microgeneration integration, present distribution networks are able to accommodate this generating capacity without major operational issues occurring. However, when the main aim is to maximize the penetration levels of these sources (in order to cope with the European Union's Climate and Energy Policy), the impacts on the distribution system are no longer negligible. In this case, several challenges face network operation such as poor voltage profiles, branch overload, *etc.* Therefore, in order to face the challenges posed by a massive deployment of DG and microgeneration, while simultaneously obtaining the potential benefits of these units, it is imperative to develop coordinated and efficient control strategies for the operation and management of these resources.

The main idea behind the present work is that it is possible to develop efficient solutions to enable large scale integration of DG and microgeneration. These solutions rely on advanced control and management algorithms that may be integrated as software modules to be installed in distribution network control centres. Voltage and reactive power control, in particular, appears as a critical issue when dealing with such demanding scenarios regarding DG and microgeneration penetration. This thesis addresses this issue in two complementary ways by developing:

- A **conceptual framework model for regional ancillary services markets for voltage control**, accomplished in a reactive power market simulator based on economic criteria for a medium-term time-horizon;
- A **methodology for voltage and reactive power control** to be integrated in a tool for managing network operation in the short-term time-horizon.

The proposal presented in this thesis is embodied in Figure 1-2.

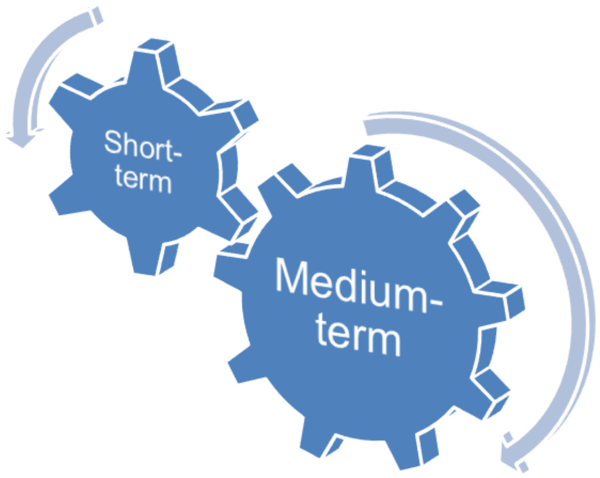

Figure 1-2 – Technical and Economical Approaches for Voltage and Reactive Power Control

In all of this, the development of a smart metering infrastructure will support the implementation of this type of solutions. This metering infrastructure will provide the means to foster the microgrid and multi-microgrid concepts in order to maximize the integration of DG and microgeneration in the distribution system.

Most of the work presented in this thesis was developed within the framework of the EU project "Advanced Architectures and Control Concepts for MORE MICROGRIDS" (Project Reference no. 19864), hereafter referred to as the More MicroGrids project[6]. This project was partly funded by the EU under the Sixth Framework Programme (FP6)[7] from the European Commission.

Based on the Treaty establishing the European Union, the Framework Programme has to serve two main strategic objectives: Strengthening the scientific and technological bases of industry and encouraging its international competitiveness while promoting research activities in support of other EU policies. These two objectives set the general scene for choosing priorities and instruments [6]. FP6 does not cover all areas of science and technology. Based on the above strategic objectives, a limited number of thematic priorities (and selected topics within the overall priorities) have been identified. One of the priorities established was in the field of Sustainable Energy Systems, under which several research projects have been approved, including the More MicroGrids project.

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[6] For more information see http://www.microgrids.eu/index.php

[7] FP6 is the European Community Framework Programme for Research, Technological Development and Demonstration. It is a collection of the actions at EU level to fund and promote research.
For more information see http://cordis.europa.eu/fp6/whatisfp6.htm

1.2 Objectives of the Thesis

The work presented in this thesis involves the development of new functionalities for control systems for a coordinated and optimized management of distribution networks, by exploiting all major available resources such as DG units, controllable loads, microgrids, storage devices, reactive power compensation devices, On-Line Tap Changing (OLTC) transformers, *etc.* In particular, the issue of voltage and reactive power control is explicitly addressed. As previously explained, these functionalities are vital in order to maximize the integration of DG and microgeneration units, without them being a burden to the distribution system.

Therefore, the three main objectives for the work developed in this thesis are the following:

- **Definition of a control architecture and management functionalities for MV distribution networks** – Considering the control architecture for network management of distribution grids with multiple MV-connected DG sources and microgrids, several key functionalities must be identified, taking into account the resources available as well as technical and operational constraints. It is intended that this multi-microgrid system be operated in a coordinated and controlled way at the MV level of the distribution system, which involves the identification of an adequate distributed control architecture.
- **Development of a framework for remunerating ancillary services for voltage control based on a market structure** – Ancillary services remuneration demands that the service volume for each operating scenario regarding reactive power needs be identified. In order to ensure an adequate remuneration mechanism, a framework for an ancillary services market for voltage control must be designed, aiming at economical efficiency, where several players present their bids to the market, which is run under the supervision of the Distribution System Operator (DSO).
- **Development of a methodology for coordinated voltage support in order to optimize operating conditions** – A tool for voltage and reactive power control must be developed in order to support network operation at the MV and LV levels, exploiting all resources available such as MV-connected DG, microgrids, OLTC transformers, reactive power compensation devices, *etc.* This functionality must be fully integrated in the functional hierarchy of multi-microgrid systems, under the responsibility of the DSO.

1.3 Outline of the Thesis

The work developed within the scope of this PhD thesis is organized into seven chapters (including the present one) and three appendixes.

The current chapter (Chapter 1) presents an introduction to a relatively new paradigm in power systems regarding the integration of DG and microgeneration (in the form of microgrids) in the electrical distribution system. The problems under investigation are described and the motivation for the work developed is presented, as well as the main objectives.

In Chapter 2, a review on the state-of-the-art regarding DG and microgeneration is given, focusing mainly on operational issues, technologies employed, main advantages and drawbacks, *etc.* In particular, the issues of voltage control and ancillary services provision in distribution systems are analysed, taking into account the impact resulting from a large scale integration of these units.

Chapter 3 presents an overview of the multi-microgrid concept based on the development of a control and management architecture able to integrate in a coordinated way DG units, controllable loads, storage devices and microgrids. This architecture aims at fully exploiting the potential benefits from the presence of these units in future distribution systems.

Chapter 4 describes an innovative approach for voltage control in future distribution systems with DG and microgrids (considered as active cells for control purposes). The resulting algorithm, based on a coordinated and optimized operation of all resources available in the distribution system, is intended to be integrated as a software module to aid the DSO in network operation.

Chapter 5 presents a proposal for an ancillary services market framework for voltage control to involve effectively DG and microgrids in system operation. The approach developed implements an ancillary services market, independent from the main energy market, that defines the cleared bids from the several market players with the goal of minimizing the cost of reactive power purchase by the DSO.

In Chapter 6, the performance of the voltage support tool and the ancillary services simulator for voltage control is evaluated, using several test systems based on real Portuguese distribution networks. The main results obtained are then carefully analysed and used to validate the approaches that were developed.

Chapter 7 presents the main contributions provided by this thesis, with emphasis on the conclusions to be drawn from the work that has been developed. Furthermore, prospects for future work to be developed are outlined.

Appendix A details the algorithm used for computing a three-phase power flow in four-wire distribution networks, as presented in Chapter 4. Appendix B presents the data concerning the test networks presented in Chapter 6 that were used for evaluating the performance of the voltage support tool and ancillary services market simulator for voltage control. Finally, Appendix C includes the diagrams for generation and load scenarios used in Chapter 6 for evaluating the performance of the voltage support tool.

"You can know the name of a bird in all the languages of the world,
but when you're finished, you'll know absolutely nothing whatever about the bird...
So let's look at the bird and see what it's doing – that's what counts.
I learned very early the difference between knowing the name of something and knowing something."

In "*What is Science?*" by Richard Feynman (b. 1918 – d. 1988)

Chapter 2 – State-of-the-Art

In this Chapter a description is made of the most relevant research work and of the latest developments regarding the state-of-the-art on distributed generation, microgrids and overall active network management. The most important issues about these topics are analysed, namely the main advantages and drawbacks, the drivers and challenges, the technologies associated and the services that can be offered to the electrical power system. In addition, an insight to voltage control techniques and an overview of ancillary services (focusing on voltage support) in networks with Distributed Generation are given.

2.1 Distributed Generation and Active Network Management

2.1.1 Introduction

The organization of electrical power systems over the last 50 to 60 years has followed a traditional hierarchical structure as shown in Figure 1-1. This structure has three different levels: generation, transmission and distribution.

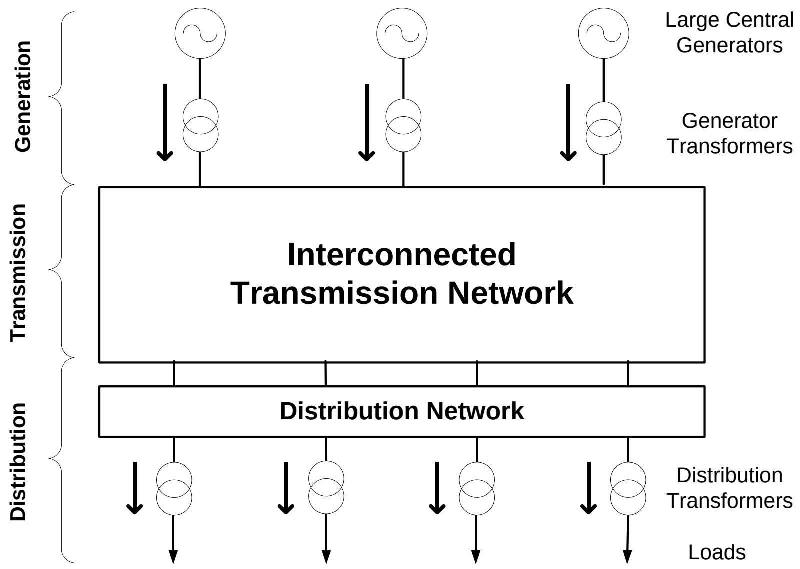

Figure 2-1 – Organization of Conventional Electrical Power Systems (adapted from [7])

The generation level is characterized by large generators that rely mostly on three types of technologies: hydro units (either run-of-the-river or dams), thermal units based on fossil-fuels (burning fuels such as coal, oil or natural gas) or nuclear units. These large central generators feed electrical power through generator transformers to an HV transmission system. The transmission system, which can cover large distances at HV levels, is then used to transport the electrical power that is finally delivered to the final customers through distribution transformers [7], [8].

Regarding the generation level, the use of large generators holds some advantages, resulting from economy of scale effects [9]:

- Size improves thermal efficiency – it is well known that the efficiency of a larger unit may be better since, for instance, heat losses related to unit size decreases in proportion, thus improving the potential efficiency of the unit.
- Possibility of doubling generation capacity for a lower cost – by assembling multiple units of the same type at one same site it may be cheaper to double the capacity as some facility costs (such as insulation, conversion, protection and control costs) can be shared, thus lowering both investment and maintenance costs.

Of course, the fuel cost (if applicable) and its availability also have great influence on both the capacity and type of technology chosen for generation. Coal, for instance, is still plentiful and cheap in several regions although serious pollution issues have to be taken into account.

In this context, the main mission of conventional Transmission and Distribution (T&D) systems is [9]:

- To cover the service territory, reaching power consumers;
- To have sufficient capacity to cover consumer peak demand;
- To provide reliable delivery to the electric power consumers;
- To ensure stable voltage quality to the electric power consumers.

In short, this traditional electric power system is structured in a strict hierarchical radial manner, comprising several voltage levels, that can pick bulk power at a few large central generation plants and deliver it in smaller amounts to a large set of customers distributed across a wide territory. As a result, the conventional power system is characterized by unidirectional flows of energy from the generation to the distribution levels using an interconnected transmission network, resulting in rather straightforward planning and operation approaches.

Furthermore, traditional utilities usually operate in well-defined geographical territories within local market monopolies under the strict supervision of regulatory bodies. These utilities own the generation, transmission, and distribution facilities within their assigned service territories and finance the construction of the required facilities subject to the approval by the relevant regulatory bodies [8].

In recent times, and particularly since the last years of the 20th Century, a growing interest in the development of DG – as opposed to the traditional large central generation – has occurred. Firstly, it should be stressed that DG is not a purely new concept. In fact, in the early days of electricity generation, generation plants would supply power only for customers that were located in close proximity to them [10]. In this case, the networks were Direct Current (DC) based and would cover only small distances to feed the demand since the supply voltage was still limited (Alternate Current – AC – was later favoured to cover large distances without requiring DC/AC conversion). Moreover, in order to keep the balance between generation and consumption, local storage (typically in the form of batteries) was used in addition to small-scale generation. As will be seen throughout this thesis, both these concepts are now coming back to the scene in a wholly new context [10].

The advent of DG faces considerable challenges and requires significant changes in the way the electrical power system is regarded at many levels, from planning to operation of the electrical power system, since the networks are changing from mere passive networks to fully active networks. The new organization of the electrical power system is shown in Figure 2-2.

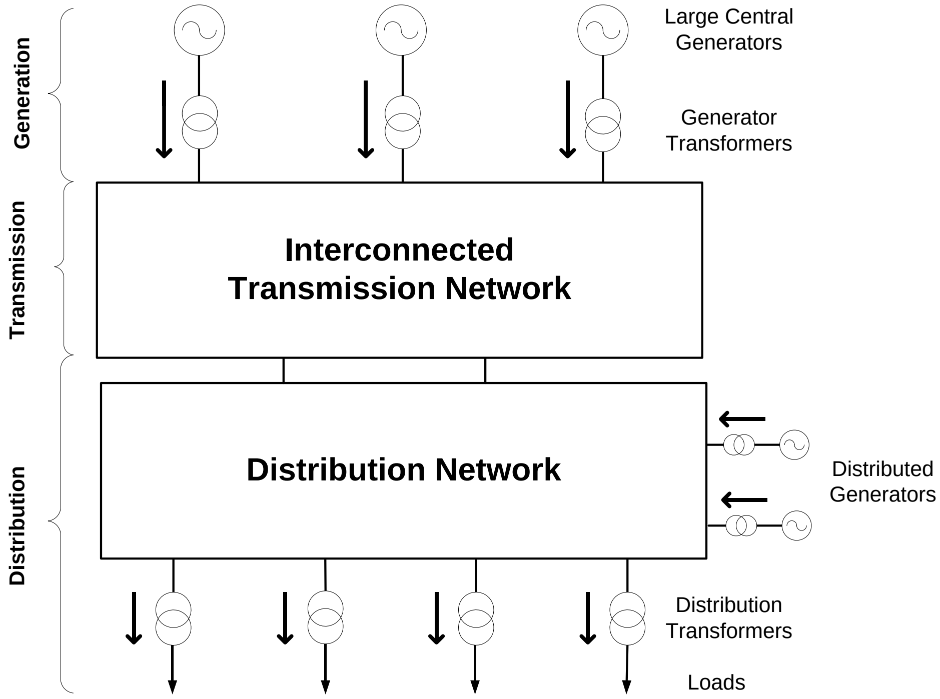

Figure 2-2 – Organization of Electrical Power Systems with Distributed Generation

2.1.2 The Distributed Generation Concept

Although there is still no consistent and unified definition, DG (also referred to in the scientific literature as Dispersed Generation, Decentralized Generation or Embedded Generation) can be loosely defined as small-scale generation connected to the distribution network. Actually, several definitions for DG can be found in the available literature.

Between 1997 and 1999, DG was investigated by two working groups of CIGRE[8] and CIRED[9]: the CIGRE working group on “Impact of increasing contribution of dispersed generation on the power system” (WG 37-23) and CIRED working group on “Dispersed Generation” (WG 04). These two reports are largely complementary and provide a comprehensive review on the

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[8] CIGRE (International Council on Large Electric Systems) is one of the leading worldwide organizations on electric power systems, covering their technical, economic, environmental, organizational and regulatory aspects.
For more information see http://www.cigre.org/

[9] CIRED (International Conference on Electricity Distribution) is a leading forum where the international electricity distribution community meets. This conference is presently organized by the Institution of Engineering and Technology (IET), formerly Institution of Electrical Engineers (IEE).
For more information see http://www.cired.be/ and http://www.cired.org.uk/

main issues associated with DG. The CIRED working group created and issued a questionnaire composed of 22 questions in order to try to identify the current state of DG in the various CIRED countries and to establish how DG was managed with reference to the distribution system [11]. Some 16 countries provided replies that served as a basis for forming a general view of the state of DG. Interestingly enough, even on the question of definition there was no clear consensus as to what constituted DG. Some countries used a definition based on the voltage level while others considered that DG was connected to circuits from which consumer loads were supplied directly. Additionally, certain definitions relied on the type of prime mover or were based on the generation not being dispatched whereas some other were based on a maximum power rating.

Jenkins *et al.* [7] agreed on some common attributes for DG, following the work of both the CIGRE and CIRED working groups: it is not centrally planned or dispatched, it is normally smaller than 50-100 MW and is usually connected to the distribution system (considering that distribution systems are networks to which customers are connected directly and which are typically of voltages from 230 V / 400 V up to 145 kV). They also considered that this broad description is to be preferred to any particular limits based either on plant size, voltage level or prime mover type.

In [9], Willis *et al.* define DG as small generators, typically ranging from 15 kW to 10 MW, that are scattered throughout a power system to provide electric power needed by electrical consumers. The term includes all use of small electric power generators, whether located on the utility system, at the site of a utility customer or at an isolated site not connected to the power grid. It is also mentioned that DG uses traditional power generation sources such as diesel, combustion turbine, combined cycle turbine, *etc.* but also includes fuel cells and renewable power generation technologies such as wind or solar because their small size makes them very convenient to connect to lower voltage parts of the electric grid. Here again dispersed generation has a different definition as it is considered as a subset of DG, referring to generation that is located at customer facilities or outside the utility system, usually with sizes in the range of 10 to 250 kW.

According to Ackermann *et al.* [12], DG is an electric power source connected directly to the distribution network or on the customer side of the meter. On one hand, this definition does not define the rating of the generation source; however some categories are suggested: micro DG for sources smaller than 5 kW, small DG for sources ranging from 5 kW to 5 MW, medium DG for sources ranging from 5 MW to 50 MW and large DG for sources ranging from 50 MW to 300 MW. On the other hand, this definition also does not address the technology used, although the following categories are proposed: renewable, modular and Combined Heat and Power (CHP), *i.e.* simultaneous generation of both electricity and useful heat. Finally, no reference is made to either the penetration level or the ownership of the DG units.

Borbely *et al.* [13] consider that the term DG refers to power generation technologies below 10 MW electrical output that can be sited at or near the load they serve. For this reason, they consider that not all small-scale technologies should be included in this category. For instance, hydro and wind generators are said to be too “fuel-dependent” (*i.e.* their location is dictated by the availability of moving water or wind) to be considered truly load-sited or distributed generation.

The International Energy Agency[10] [14] states that DG is a generating plant serving a customer on-site or providing support to a distribution network, connected to the grid at distribution level. In terms of technologies used, it generally includes engines, small (and micro) turbines, fuel cells and photovoltaic (PV) systems, and normally excludes wind power since it is considered that this type of energy is mostly produced on wind farms rather than for on-site power requirements. In this case, rather than being a synonym of DG, dispersed generation is regarded as DG plus wind power and other generation, either connected to a distribution network or completely independent of the grid.

For Dondi *et al.* [15], DG is a small source of electric power generation or storage (typically ranging from less than a kW to tens of MW) that is not a part of a large central power source and is located close to the load. DG includes biomass based generators, combustion turbines, concentrating solar power and PV systems, fuel cells, wind turbines, microturbines, engine/generator sets, small hydro plants as well as storage technologies. These can either be grid connected or operate independently of the grid. Those connected to the grid are typically interfaced at the distribution system, and thus dispersed across the utility's electric network rather than concentrated in a single location.

In conclusion, and even though there are some significant differences between all these DG definitions, some common grounds can be found: it is usually connected to the distribution system and includes generators with relatively low capacity (at least when compared to large central generators). As shown above, no consensus is reached regarding such issues as DG technologies and applications, location or power capacity rating.

2.1.2.1 Distributed Energy Resources

Nowadays, DG is considered within the wider context of Distributed Energy Resources (DER), which form the core of the future power system. According to Lopes *et al.* [5], DER include not only DG but also distributed energy storage devices as well as responsive loads while other authors do not include storage within the DER concept [12], [14]. Throughout this thesis, the term DER will follow the definition proposed by Lopes *et al.* [5].

Considering the new paradigm in electrical power systems, energy storage can be an important supplement to DG for three main reasons [9]:

- It can be used for stabilization purposes, allowing DG to run at a constant, stable output level;
- It can provide energy to ride through periods when DG is not available (for instance, considering solar power at night-time);
- It can allow a non-dispatchable DG unit to operate as a dispatchable unit by enabling its output to differ from the power being supplied to the grid.

[10] The International Energy Agency (IEA) is an intergovernmental organization which acts as energy policy advisor to 28 member countries (including Portugal) in their effort to ensure reliable, affordable and clean energy for their citizens.
For more information see http://www.iea.org/

In addition, important resources can also be found in the demand side. It is considered that these resources include load management systems that are able to shift electricity use from peak periods to off-peak periods and ensure energy efficiency options (*e.g.* reduce peak electricity demand, increase building efficiency or reduce overall electricity demand). Consequently, DER are not only based on local generation on the customer's side of the meter but also on means to reduce peak or average customer demand, which will largely influence the electricity supply from the distribution network [12].

2.1.3 Main Distributed Generation and Storage Technologies

There is currently a wide variety of technologies that are usually associated to DG. These technologies may vary according to many parameters such as power rating, application type, electric conversion efficiency, type of fuel, investment and operation costs, GHG emissions, *etc.* [10].

Several approaches to sort out the many different generating technologies can be found in the available scientific literature. According to Puttgen *et al.* [8], these technologies may be sorted into two separate categories: renewable and non-renewable. In turn, Ackermann *et al.* [12], although stating that the type of technology used for DG is not relevant for their proposed DG definition, suggest three alternative categories: renewable DG, modular DG and CHP. Finally, in [16], some other categories are proposed such as the classification in traditional generators (combustion engines) and non-traditional generators (remaining technologies).

Nevertheless, one issue that will significantly influence the impact of DG in the distribution system, particularly considering large-scale integration scenarios for DG, is the degree of controllability of the technology employed. Consequently, DG technologies can be divided into three categories, according to their degree of controllability:

- Controllable;
- Partially controllable;
- Non-controllable.

Table 2-1 presents a non-exhaustive list of the most common DG technologies, showing the typical range of capabilities and degree of controllability [8], [10], [12], [17].

Table 2-1 – Main Distribution Generation Technologies

Technology	Typical Capability Ranges	Controllability
Solar PV	A few W to a few MW	Non-controllable
Wind	A few hundred W to a few MW	Non-controllable/ Partially controllable*
Microturbines	A few tens of kW to a few MW	Controllable
Fuel Cells	A few tens of kW to a few tens of MW	Controllable
Internal Combustion Engine	A few kW to a tens of MW	Controllable
Combined Cycle Gas Turbines	A few tens of MW to several hundred MW	Controllable
Hydro	A few kW to hundreds of MW	Non-controllable Partially controllable**

* Depending on the type of technology used (conventional asynchronous generator, doubly-fed induction generator, synchronous generator with gearbox…)
** Depending on there being some type of reservoir associated or not

Some of these technologies, as well as storage solutions, are briefly described in the following sections.

2.1.3.1 Photovoltaic Panels

PV generation (*i.e.* direct conversion of sunlight to electrical energy) is a relatively well established technology for several applications such as providing power for satellite equipments or for sites remote from the distribution grid [7], [17]. Although there is a number of large MW scale projects already deployed[11], the main interest is now focusing on the application of small modules to roof tops and buildings in general.

The basic unit of PV is a cell usually made of doped silicon crystal. Cells are connected to form a module or panel and modules are connected to form an array in order to achieve the desired power capacity. Typical efficiency values are in the range of 15-20%,depending on the particular PV technology used [9].

Generally, PV panels have two main applications: grid-connected systems (with an inverter to serve AC loads) and stand-alone systems (supplying DC power directly to a DC load or used in combination with some form of storage such as “deep cycle” batteries). The use of the power electronic interface for grid-connected applications allows a better control of the output power. Frequently, PV panels use a Maximum Power Point Tracker (MPPT) in order to operate at the maximum power point, *i.e.* the operating condition where the most energy is captured [18].

The main advantages of this type of technology are its modularity, with a linear cost *vs.* capacity relationship that makes it ideal for small applications, and the fact that it is environmentally benign with no noise, pollution or vibration (in spite of adverse issues such as land use).

PV generation is foreseen to have a large importance in the future since technological maturity and market demand will lower considerably the installation costs so that it will become one of the most used technologies in the future generation mix. In fact, considering the connection of small PV installations directly to customers’ circuits (interfacing with the LV distribution network), a potential large number of residences and commercial buildings may be equipped with PV generators in a near future [7].

2.1.3.2 Wind Generators

Wind energy is a form of energy used for decades and thus has more cumulative experience than most other energy sources. In fact, wind generation is possibly the renewable source with the most mature technology. Wind generation uses wind turbines to exploit the wind’s kinetic energy in order to drive electric power generators. Basically, the wind rotates the blades which in turn rotate their attached shaft. This shaft moves a generator that produces electricity.

[11] The Moura PV power station (located in Alentejo, Portugal), one of the biggest in the World has an installed capacity of 46 MW.

Although the energy characteristics of large wind turbines are closer to conventional centralized energy sources, small and micro wind turbines can also be used to provide power in the area of 20-100 kW [16].

Different wind turbine designs may be used especially horizontal axis wind turbines (the most commonly available design such as in traditional windmills) and vertical axis wind turbines (with some advantages in turbulent wind flow regimes) [17].

Several types of wind generators are currently available, either constant-speed or variable-speed wind turbines, using induction, synchronous, DC and variable-speed AC generators, among other technologies [9].

The main advantages of wind generators are:

- There is no fuel charge;
- It is non-polluting;
- Units are modular with a fairly linear power *vs.* cost relationship;
- It is potentially a 24-hour per day source of energy (unlike PV generation).

Wind generation is one of the dominating technologies regarding RES in the current generation mix in several countries, exhibiting a very fast grow in recent years.

2.1.3.3 Microturbines

Microturbines are seen as one of the most promising technologies for DG. They are also suitable for use in CHP applications.

Microturbines are small capacity combustion turbines, usually operating on natural gas (but may also use propane or fuel oil). These units have a rated output that may vary between 30 kW to 400 kW [17]. The most common configuration for a microturbine is a single-shaft machine (*i.e.* with the compressor and turbine mounted on the same shaft as the electric generator) with no need for gearboxes and associated parts).

Microturbines have high rotational speeds that may vary between 50’000 and 120’000 rpm, depending on the specific capacity of the microturbine [8]. This high-frequency output must first be rectified and then converted to the nominal 50 Hz (or 60 Hz as in the USA or Canada). Efficiencies in the range of 25-30% may be achieved if a heat recovery system transferring waste heat energy from the exhaust stream back to the incoming air stream is used [8], [17].

Microturbines have a series of advantages regarding other DG technologies, namely:

- They are compact in size and light in weight, thus being easy to install on-site even if there are space limitations;
- They are reasonably efficient and have low emissions;
- They have well-known technology, with fast start-up times and good load-following characteristics;
- They have reduced maintenance needs;
- They can be flexible and efficiently controlled through to their power electronic interface.

2.1.3.4 Fuel Cells

Fuel cells are probably the technology that deserved the most development attention and raised considerable expectations in the past years. Basically, the fuel cell is a device used to convert the chemical energy contained in a particular fuel directly into electric energy. Usually, the fuel used is hydrogen, which can be obtained by hydrocarbons reformation or by electrolysis of water [16].

Individual fuel cells are combined into various series and parallel configurations to constitute a fuel cell system. The fuel cell system produces DC electricity and is typically connected to a local utility system through a power electronic interface (DC-AC converter). Fuel cells may be used for both mobile and stationary applications. Their efficiency depends heavily on the type of fuel cell used but can reach up to 60% [17].

There are several types of fuel cells depending on the electrolyte used, each one with their specific characteristics, advantages and drawbacks. A list with the most common fuel cell types is presented below.

- Proton Exchange Membrane Fuel Cell (PEMFC);
- Alkaline Fuel Cell (AFC);
- Direct Methanol Fuel Cell (DMFC);
- Phosphoric Acid Fuel Cell (PAFC);
- Molten Carbonate Fuel Cell (MCFC);
- Solid Oxide Fuel Cell (SOFC).

The characteristics of the several types of fuel cells, and their corresponding performances, have significant influence on the application intended: for instance, PEMFC are typically flexible cells since their output can vary quickly to meet changes in power demand, which makes them suitable for mobile applications, contrary to SOFC, which are mainly used in medium and large scale stationary applications. More details on the type of fuel cells available can be found in [8], [16], [17].

The main advantages of fuel cell systems are:

- There is an almost total absence of moving parts;
- There is no combustion involved, which makes them environmentally friendly;
- They are modular, which allows flexibility in matching specific power needs.

2.1.3.5 Storage Devices

The use of storage devices with DG units is a combination that compensates the incapability of many DG sources to follow energy consumption and, as a result, comply with network requirements.

Concerning energy storage technologies, there are several available solutions depending on the application they are intended for, such as:

- Batteries;
- Super-capacitors;
- Flywheels;

- Compressed-air systems;
- Flow batteries.

On the other hand, storage systems may fall into two different categories, according to scale and application [19]:

- Small-scale systems where the energy can be stored as kinetic energy (flywheel), chemical energy, compressed-air or in super-capacitors for low/medium power applications in isolated areas;
- Large-scale systems where the energy can be stored as gravitational energy (hydraulic systems), chemical energy (accumulators, flow batteries) or compressed air (or coupled with liquid or natural gas storage) for network connection and power quality control applications.

2.1.4 Drivers and Challenges for Distributed Generation Growth

There have been a series of drivers pushing forward the growth of DG and the recent focus on its impact on both power system operation and planning. In [5], three main drivers are identified:

- Environmental drivers;
- Commercial drivers;
- National/regulatory drivers.

Especially following the signing of the Kyoto Protocol, environmental impact has been a key factor for the development of future electrical power systems. The Kyoto Protocol[12] was adopted in Kyoto, Japan, on 11th December 1997 and entered into force on 16th February 2005. This protocol was signed by 187 states[13] (including Portugal) and sets binding targets for reducing GHG emissions [20]. GHG emissions include CO_2 and Nitrogen Oxide compounds, such as NO_x. These targets are one of the main enforcers of the DG paradigm since it is seen that the full deployment of DG will foster the use of RES and CHP applications. Of course, this does not mean that most of the RES, which include hydro, PV and wind generation, will be connected only at the distribution level. For example, large onshore and offshore wind farms are usually connected directly at the transmission level.

In addition, the establishment of a Carbon Market (emissions trading specifically for carbon dioxide) is expected to be a stepping stone towards the development of a sustainable power system. This was one of the ways found for making countries meet their obligations under the Kyoto Protocol to reduce carbon emissions and thereby mitigate the alleged global warming. Basically, the so-called carbon credits are based on the “you pollute, you pay” policy since the Kyoto Protocol established caps or quotas for the maximum amount of GHG for developed and developing countries. In turn these countries set quotas on the emissions of installations run

[12] The Kyoto Protocol is an international agreement linked to the United Nations Framework Convention on Climate Change (UNFCCC).
For more information see http://unfccc.int/kyoto_protocol/items/2830.php

[13] As of the 3rd December 2009, according to the Kyoto Protocol Status of Ratification.
For more information see http://unfccc.int/kyoto_protocol/status_of_ratification/items/2613.php

by local businesses and other organizations, generically termed "operators". Basically, each "operator" has an allowance of credits, where each unit gives the right to emit one metric tonne of carbon dioxide or other equivalent GHG. "Operators" that have not used up their quotas can sell their unused allowances as Carbon Credits, while others businesses that are about to exceed their quotas can buy the extra allowances as credits, privately or on the open market. By permitting allowances to be bought and sold, each "operator" can seek out the most cost-effective way of reducing its emissions, either by investing in more environmentally friendly technologies and practices or by purchasing emissions from another operator. Once this type of markets is fully established, RES will most likely become competitive in terms of energy cost with the conventional generating technologies based on fossil-fuels. In theory, the use of auction mechanisms for these allowances ensures a fair treatment for all players. Furthermore, as energy use (and consequently emission levels) is foreseen to increase in the future, the number of companies needing to buy credits will increase, and the rules of supply and demand should push up the market price, thus encouraging more "environmentally friendly" activities. The European Union has developed an Emission Trading System (ETS), which is the largest multi-national emissions trading scheme in the world and a major pillar of European climate policy.

Moreover, from the environmental perspective, another driver for DG is the possibility of avoiding the construction or replacement (due to capacity constraints) of new grid infrastructures such as transmission and distribution lines, power transformers and large power plants, which normally bear strong public opposition [5], [10]. Logically, this does not mean that DG technologies have no environmental impact and, therefore, may not face public opposition. In fact, concerning wind farms, there is frequently high reluctance from lobby groups based on noise and visual impact, as well as damages to bird fauna, attributed to this type of energy source.

Concerning commercial drivers, these are related to the fact that general uncertainty in electricity markets should, in principle, favour small generation schemes since the financial risk is also proportionally smaller. In general, in a "re-regulated" environment with open access to the distribution system, it is expected that there will be greater opportunities for the establishment of DG [5], [7].

Furthermore, DG can be a cost-effective solution for improved power quality and reliability. Understandably, high reliability implies high investment and maintenance costs for both the generation and network infrastructure. Given the change brought about by the liberalisation of energy markets, the incentives for cost-effectiveness may lead to a decrease in reliability. Consequently, this may also lead to an investment in DG from industries (in businesses such as chemicals, petroleum refining, *etc.*) that are very sensitive to these issues if grid supplied electricity is not very reliable [10]. Concerning power quality in general, there is room for voltage profile improvement or reduction of interruption times. In the latter case, this will only be true if DG is allowed to stay connected during power outages [5]. Additionally, the proximity of the DG units to the point of electricity consumption, especially in the case of end-users with low power quality, may allow an improvement in the continuity and reliability of service [16].

On the subject of national and regulatory drivers, these are related to the diversification of energy sources by using diverse primary energy sources that may reduce the dependence on fossil fuels in order to enhance energy security. Moreover, DG will support competition policy since many new players will arrive to the market and it is expected that the introduction of competition in generation and customer choice will, in a long run, deliver low energy prices and better quality of service [5].

Nevertheless, several challenges must be overcome in order to accommodate efficiently DG in the electric power system. Within these, technical problems in particular should be carefully assessed and dealt with.

The main technical challenges to increased DG penetration are [5], [7]:

- Network voltage changes – The voltage rise effect in particular is a key factor that can limit the amount of DG capacity to be connected to the distribution system, especially in rural networks. This effect is addressed in detail in Section 2.3. In addition, voltage imbalances may occur when different feeders originating from one same distribution substation have considerably different DG penetration levels.
- Power quality issues – Two main aspects are usually considered: transient voltage variations and voltage harmonic distortion. Depending on several issues such as capacity, type of prime mover, interface, location, *etc.* the effect of DG on network voltage can be either positive or negative. In practice, meeting the required standards either from the energy converter side or from the grid side causes no problems to grid operation.
- Congestion problems – In some scenarios, DG may alter branch flows significantly, which may pose additional problems in terms of managing energy flows. This may ultimately cause branch overload, especially in the case of high levels of renewable-based DG integration, which may inject large amounts of energy into the distribution system.
- Protection issues – Several different aspects can be considered here and need to be carefully addressed: protection of the generation equipment from internal faults; protection of the faulted distribution network from fault currents supplied by DG; anti-islanding or loss-of-mains protection (islanded operation of DG is likely to be allowed in the future as DG penetration increases [5]) and impact of DG on existing distribution system protection. Additionally, the integration of DG may cause an increase in the fault level of distribution networks, which in turn may cause problems to the operation of switchgears that were not designed taking this effect into account [7].
- Stability issues – The presence of DG may have a considerable impact on the stability of the electric power system since the networks are no longer passive. As DG penetration grows, it is necessary to assess the impact on stability, either in terms of transient stability or long term dynamics. In fact, if DG is expected to be able to provide support services for the distribution network, this issue becomes critical: for instance, the loss of a large central generation unit may provoke mal-operation of protections (namely sensitive frequency protection schemes), causing the trip of large amounts of DG, which will affect system frequency even further [7]. In addition, the issue of restoration after an outage has to be carefully analysed.

There are also some commercial challenges that must be addressed. Several case studies indicate that a significant increase in DG integration requires active management of the distribution system [5]. This will involve managing not only the generation side (*i.e.* DG units) but also loads and storage resources present in the distribution network, within the integrated concept of DER. In order to fully implement this concept, it is necessary to assess both the benefits and costs of developing such a system.

However, at the present time, distribution companies have no major incentives to connect DG or to offer active management services. In fact, most DG connections are still based on a "fit-and-forget" philosophy, which means that DG is regarded as a mere passive element in the distribution system. This philosophy inevitably leads to a limitation on the amount of DG that can be connected to the grid. However, this can be tackled by implementing one of the following three approaches [5]: recover the cost of implementing active management directly through the price control mechanism (resulting in increased charges for network use for either DG or demand customers), establish incentives to reward companies for installing DG or establish a market mechanism that would create a commercial environment for the development of active networks.

Finally, some regulatory barriers may slow down the large-scale deployment of DG since there is the need for articulating appropriate policies to support DG integration in the grids. There are still no clear policies or regulatory instruments to promote efficiently the thriving of DG.

2.1.5 Distributed Generation Siting

As seen in the previous section, the integration of DG can have significant impact on the distribution system, especially if large-scale DG integration scenarios are considered. The impact of DG is influenced not only by the characteristics of the network it is connected to (whether it is radial or meshed, with longer or shorter feeders, with more or less resistive lines or cables, *etc.*), but also by the location of the DG sources present, as well as their sizing.

Therefore, planning strategies for integrating DG in the distribution grid, including the location and size of the units, can be developed in order to obtain the most benefits from DG sources. In fact, some authors address the issue of DG siting and sizing by formulating an optimization problem that aims at minimizing investment and operation costs, reducing losses, *etc.* [21], [22], [23], [24]. Of course, this vision assumes that DG is either owned by the distribution company (and consequently considers that this company wants to optimize its resources by taking the most profit out of DG integration), or that the distribution company has the power of choosing where and how DG can be connected. In this context, it is considered that distribution planners will need new planning tools in order to maximize benefits in face of the uncertainty following large-scale DG deployment [25]. Several papers describing different methods for optimal DG siting and sizing can be found in the available technical literature.

For instance, El-Khattam *et al.* [26] propose a new heuristic approach for DG capacity investment planning, from the perspective of the distribution company. In this case, optimal DG capacity sizing and placement is obtained through a cost-benefit analysis based on an optimization model that aims at minimizing the investment and operating costs of the distribution company, as well as the payment toward loss compensation.

A similar approach is followed by Celli *et al.* in [25]. In their paper, a multi-objective formulation is proposed based on genetic algorithms for the placement and sizing of DG resources into existing distribution networks. This methodology allows the planner to decide on the best compromise between the cost of network upgrading, cost of power losses, cost of energy not supplied and cost of energy required by the served customers.

On the contrary, the recent vision concerning DG integration assumes that DG will not appear at pre-defined sites, following a planning strategy by the DSO. In fact, it is expected that the DSO will not own most of the DG units and will be unable to define exactly the connection points to the distribution grid or the capacity of these units, especially for DG connected at lower voltage levels.

Nonetheless, optimal siting and sizing methodologies may be employed to define incentives to DG connection. This can be done, for instance, by remunerating DG units that are placed at certain locations in the distribution network that bring benefits to the DSO such as loss reduction, improvement of voltage profiles, *etc.*

2.1.6 Active Distribution Network Management

Active distribution network management is considered as a key factor to achieve cost-effective solutions following DG integration in distribution grids at both the planning and operation stages of the distribution system. In fact, this is a huge step beyond the current "fit-and-forget" approach.

Historically, the main function of the passive distribution system was to deliver the power from the transmission network to lower voltage level consumers. The design of the networks was based on deterministic power flow studies for extreme situations in order to allow safe operation with a minimum amount of control. This meant that control problems would occur essentially at the planning stage rather than during operation. However, with the advent of DG and improved control by means of Information and Communication Technologies (ICT), this philosophy needs to be revised as it can severely limit the amount of allowable DG integration.

Figure 2-3 shows a schematic representation of today's DG capacities, distribution and transmission networks, as well as central generation and their future development under two alternative scenarios. First, the "Business-As-Usual" (BAU) scenario represents the development of the system under a traditional paradigm based on centralized control and more passive distribution networks. The alternative active future represents the capacity of the system with both DG and demand side fully integrated into system operation under a decentralized paradigm in which DG is able to participate in system management.

Under the BAU future, large-scale DG integration may be able to displace a significant amount of the energy produced by central generation. However, if DG and demand side are not integrated in system operation, conventional central generation will still need to increase since it will be necessary to provide system support services (such as load-following, frequency and voltage regulation and reserves) that are required to sustain secure system operation. This means that even high levels of DG will not be able to displace a significant capacity from conventional central generation. In addition, since DG is connected directly to the distribution networks, an increase in both transmission and distributions networks capacities will be required in order to maintain traditional passive operation of these networks and the centralized control philosophy.

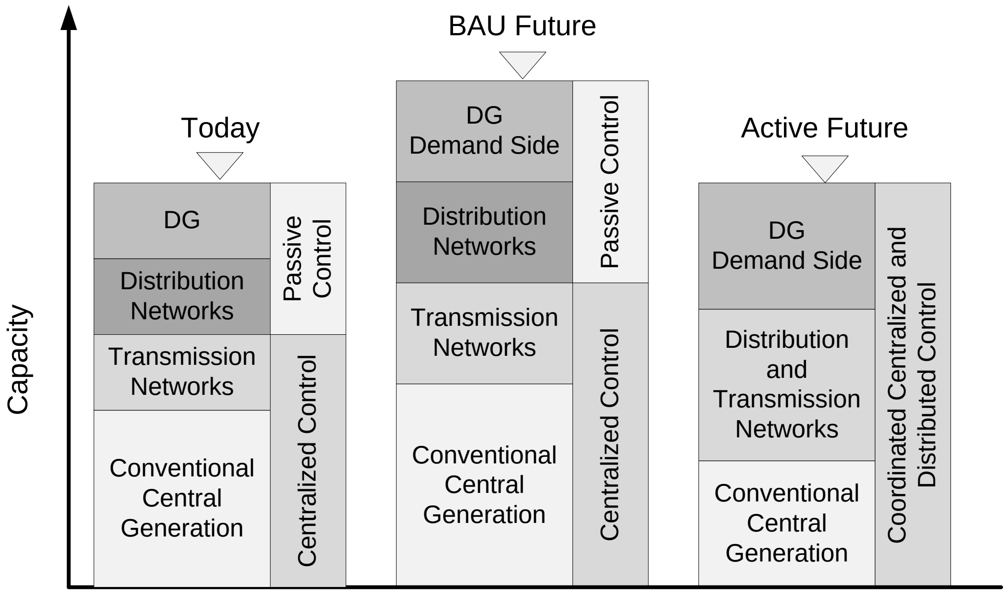

Figure 2-3 – Relative Levels of System Capacity under Centralized and Distributed Control Strategies (adapted from [27])

Alternatively, in the active future scenario, by fully integrating DG and demand in network operation, controllable DG and demand side management will share the responsibility of delivering system support services, a role that was previously reserved to central generation. In this case, DG will be able to displace effectively not only energy supplied by central generation but also its controllability, thus reducing the required central generation capacity. In order to achieve this, the operating practice of distribution networks needs to change from passive to active, which will necessitate a shift from traditional central control philosophy to a new coordinated centralized and distributed control paradigm. This scenario will require significant ICT capabilities, as well as new decision support tools to use all the information available from DG and demand side. Of course, this will bring additional complexity to system operation but, with correct development, this new paradigm may facilitate more reliable, cost-effective system that are able to achieve maximum utilization of all resources available.

In conclusion, the connection and management of DG in the distribution network poses a challenge to the DSO in order to make the transition from passive to active, integrated networks. Several issues such as voltage rise effect (discussed in Section 2.3) present a problem to the DSO which, without proper management, can increase the cost of connection for DG due to network reinforcement requirements.

Active management of distribution networks will enable the DSO to maximize the use of existing circuits by taking full advantage of generator dispatch, control of transformer taps, voltage regulators, reactive power management and system reconfiguration in an integrated, coordinated way. This active approach to system operation can reduce the negative impact of DG on the network, thus minimizing requirements for reinforcements [27].

In addition, these active management strategies can also contribute to balance load and generation and to provide ancillary services (discussed in Section 2.4). Also, such systems may provide real-time network monitoring and control at some key network nodes by communicating with generator controls, loads and other controllable network devices such as reactive compensators, voltage regulators and OLTC transformers. Several functions such as state estimation, power flow computation, voltage assessment and fault level analysis can provide relevant inputs to allow better scheduling decisions for network management.

2.2 Microgeneration and Microgrid Systems

2.2.1 Introduction

During the last two decades, the deployment of DG sources has been growing steadily. During this process, distribution utilities have been one of the industry's most concerned stakeholders. The main reason is that DG is connected primarily within their distribution networks (mainly at the MV and HV level), which have been designed under the paradigm that consumer are passive elements of the grid and power flows are unidirectional, from the substations to the consumers.

However, different DG technologies such as microturbines, PV panels or fuel cells may have rated powers ranging up to a hundred kW and can be directly connected to the LV networks. This type of DG, integrated directly next to the customer side at the LV level, is usually called microgeneration and the corresponding generating units are called microgenerators or microsources. In this context, microgeneration units, located at user sites, emerge as a promising opportunity to meet growing customer needs for electric power, with an emphasis on reliability and power quality. Furthermore, considering increased levels of microgeneration integration, the distribution network (particularly at the LV level) can no longer be considered as a passive element. On the contrary, microgeneration can have a significant impact on the LV network and the focus has been on assessing how much DG can be *tolerated* before its collective electrical impact begins to originate problems in the distribution system in terms of stability or voltage, for instance.

Therefore, an adequate control and management architecture is required in order to facilitate the integration of microgeneration and active load management schemes. Besides, the control and management of such a system should answer for all the benefits that may be achieved at all voltage levels of the distribution network. This means that different hierarchical control strategies need to be adopted at different network levels. One promising way to fully accomplish the emerging potential of microgeneration is to assume a systemic approach – the microgrid concept.

Generically, microgrids are LV distribution systems with DER that can be operated interconnected to the main power grid or in an autonomous mode. The operation of the DER may bring benefits to the system if efficiently managed and coordinated.

As it happens with DG, there is also no unified definition of the microgrid concept or its architecture although there are many common points between the several approaches that can be found in the existing technical literature.

According to Chowdhury *et al.* [28], microgrids are small-scale, LV CHP supply networks designed to supply electrical and heat loads for a small community, such as a suburban locality, a university, a commercial area, an industrial site or a municipal region. Furthermore, a microgrid is essentially an active distribution network since it accommodates DG systems and different loads at distribution voltage level. The microsources employed are usually renewable DER integrated together to generate power at distribution voltage. From the operational point of view, the microsources are usually equipped with power electronic interfaces to provide the required flexibility to ensure operation as a single aggregated system and to maintain the specified power quality and energy output. This flexibility allows the microgrid to present itself to the main utility power system as a single controlled unit that meets local energy needs for reliability and security.

For Driesen *et al.* [29], a microgrid may comprise part of an MV/LV distribution system and clustered loads that are served by single or multiple DER. They also state that the microgrid approach may promote:

- A highly efficient energy delivery and supply system based on co-locating DG and loads;
- A secure and reliable power supply configuration with service differentiations based on customer technology preference and power quality requirements;
- An energy delivery infrastructure that has sufficient power generation and balancing sources to operate independent from the main grid in an autonomous manner during power outages or an energy crisis.

One very important feature that makes the microgrid a special case will be its ability to operate autonomously, *i.e.* islanded or independent from the main power system. This operating condition can arise due to the occurrence of a disturbance in the network, such as a fault and the subsequent switching actions, or due to pre-planned switching events for maintenance purposes, for instance [30], [31], [32]. However, several regulatory barriers have to be overcome since current technical practice does not allow the islanding of active portions of the grid.

The microgrid concept may be implemented in a variety of scales, considering a part of an LV grid, an LV feeder or even a facility, such as a house. A general classification of possible microgrid architectures and their characteristics based on type of application, ownership structure and type of loads served is presented in Table 2-2.

Two of the main microgrid concepts, described in detail in the following sections, are the Consortium for Electric Reliability Technology Solutions[14] (CERTS) microgrid approach from the USA and the European approach from the EU project "MICROGRIDS – Large Scale Integration of Microgeneration to Low Voltage Grids"[15].

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[14] For more information see http://certs.lbl.gov/

[15] For more information see http://www.microgrids.eu/micro2000/index.php

Table 2-2 – Possible Microgrid Architectures and their Characteristics ([29] and personal research)

	Utility Microgrids		**Industrial/Commercial Microgrids**		**Remote Microgrids**
	Urban networks	Rural feeders	Multi-facility	Single facility	–
Application	Downtown areas	Planned islanding	Industrial parks, university campus and shopping centres	Commercial buildings and residential buildings	Remote communities and geographical islands
Technologies	PV, wind, microturbine, and CHP	Hydro, PV and wind	Microturbine, PV, CHP and fuel cell	Microturbine, PV, CHP and fuel cell	Hydro, PV and wind
Main Drivers	Outage management and RES integration		Power quality enhancement, reliability and energy efficiency		Electrification of remote areas and reduction in fuel consumption
Benefits	GHG reduction, supply mix, congestion management, upgrade deferral and ancillary services		Premium power quality, service differentiation (reliability levels), CHP integration and demand response management		Supply availability, RES integration, GHG reduction and demand response management
Operating Modes	Interconnected mode Islanded mode		Interconnected mode Islanded mode		Islanded mode
Unplanned Transition	Faults (on upstream or adjacent feeders)		Main grid failure and power quality issues		–
Pre-planned Transition	Maintenance actions		Maintenance actions and energy price (peak time)		–

2.2.2 The CERTS Microgrid Concept

The microgrid concept was originally developed within the CERTS [33]. The CERTS microgrid concept assumes an aggregation of loads and microsources operating as a single system providing both power and heat [33], [34]. According to this concept, the majority of the microsources must be power electric based to provide the required flexibility to ensure operation as a single aggregated system. It is this flexibility of control that allows the microgrid to present itself to the bulk power system as a single controlled unit that meets local needs for reliability and security. This is also the reason for the CERTS microgrid concept not to include any particular kW power capacity, though it considers typically microturbine technologies with power ratings less than 500 kW and eventually fuel cells that may exceed that value.

Furthermore, this approach does not accommodate the traditional operating principle that DG must be shut down automatically if problems arise in the grid. In fact, the CERTS microgrid is designed to seamlessly separate or island from the grid and later reconnect to the grid once these problems are resolved.

As the microgrid is seen as a single self-controlled entity, its architecture insures that the electrical impact on the bulk power provider at least qualifies as “Good Citizen”, *i.e.* it complies with the grid rules and does no harm beyond what would be acceptable from an existing consumer. Although there are still some technical barriers to overcome, it is seen that the microgrid may also behave as a “Model Citizen”, able to serve as a small source of power or ancillary services. This would bring additional benefits to the distribution system such as congestion relief, postponement of new generation or delivery capacity, response to load changes and local voltage support.

In addition, from the perspective of the grid, a microgrid as a controlled entity can be operated as a single aggregated load. This allows establishing contractual agreements with the bulk power provider to cover pattern of usage of the microgrid system that are at least as strict as those covering existing customers.

Finally, customers benefit from the microgrid concept since it is designed and operated to meet their local needs for heat and power as well as provide uninterruptible power, enhance local reliability, reduce feeder losses and support local voltages.

2.2.2.1 Control and Management Architecture

The key issues related to the microgrid structure include the interface, control and protection requirements for each microsource as well as voltage control, power flow control, load sharing during islanding, protection, stability and overall operation of the microgrid system. Another very important function is the microgrid ability to operate connected to the grid and to make a smooth transition to and from island mode.

The CERTS microgrid architecture is shown in Figure 2-4. It is a radial system comprising three feeders (A, B and C) and some loads. The microsources present are either microturbines or fuel cells with power electronic interfaces. The Point of Common Coupling (PCC) is on the primary side of the transformer and it defines the separation between the microgrid and the main power grid.

The presence of the microsources spread along the feeders allows analysing their effect on reducing line losses, supporting voltage and/or using their waste heat. The feeders are usually 480 V or smaller. Each feeder has several circuit breakers and power and voltage flow controllers. The power and voltage controller near each microsource provides the control signals to the source, which regulates feeder power flow and bus voltage to the levels defined by the Energy Manager. The power of the microsources would be increased or decreased according to load changes to hold the total power flow at the dispatched level.

In addition, during disturbances, feeders A and B can island due to the separation device and feed sensitive loads, provided there is enough local generation to meet the demand.

The CERTS microgrid architecture assumes three critical functions:

- **Microsource Controller (MC)** – The Power & Voltage Controller, coupled with the microsource, provides fast response to disturbances and load changes without relying on communications.

- **Energy Manager** – Provides operational control through the dispatch of power and voltage set-points to each Microsource Controller.
- **Protection** – Microgrid protection requires unique solutions to provide the required functionalities since the sources are interfaced using power electronics.

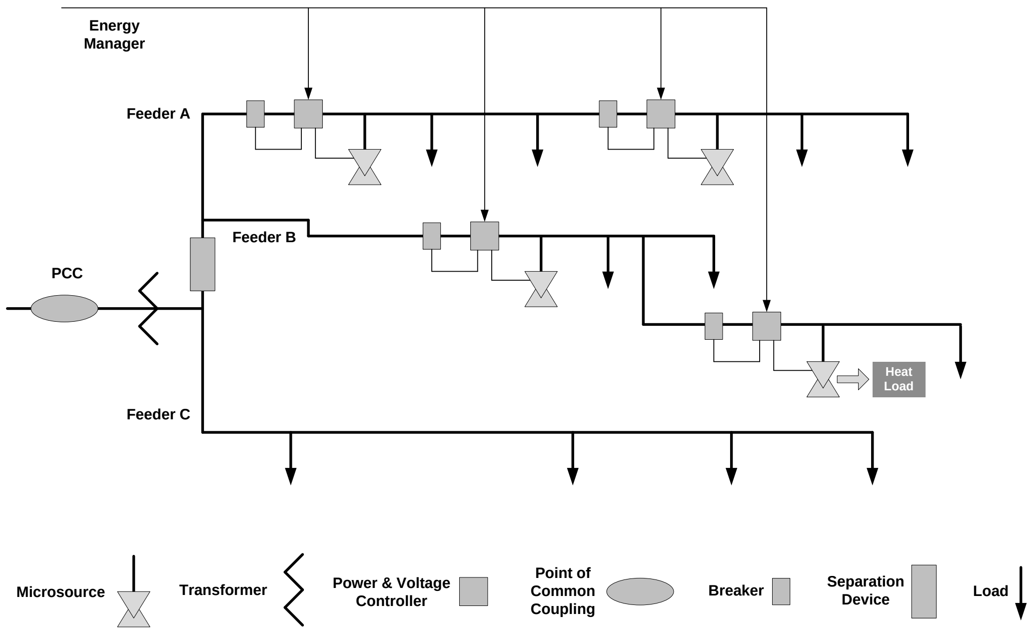

Figure 2-4 – CERTS Microgrid Architecture (adapted from [33])

The basic operation of the microgrid depends on the MC being able to regulate power flow on a feeder, regulate the voltage at the interface of each power source and insure that each microsource is able to pick up a share of the load as demand changes, especially in island mode. In addition, the ability of the system to island smoothly and to automatically reconnect to the main power grid is another important function. The MC is able to respond quickly (in milliseconds) using only local values for voltage and current to control the microsource during most events. Consequently, fast communication among microsources is not required for microgrid operation: each inverter is able to respond to load changes in a predetermined manner without data from other locations – "plug-and-play" capability, *i.e.* microsources can be added to the microgrid without changes to the control and protection of the units that are already part of the system.

In turn, the Energy Manager is in charge of microgrid operation through the dispatch of power and voltage set-points to each MC, according to the operational needs of the microgrid and criteria such as:

- Insuring that the necessary heat and electrical loads are met by the microsources;
- Insuring that the microgrid satisfies operational contracts with the bulk power provider;
- Minimizing emissions and/or system losses;
- Maximizing the operational efficiency of the microsources.

Finally, the protection coordinator must respond to both system and microgrid faults. For a fault on the main power grid, the microgrid should isolate rapidly in order to preserve sensitive loads. If the fault occurs within the microgrid, the protection should isolate the smallest possible section of the feeder in order to eliminate the fault.

2.2.3 The EU Microgrid Concept

The European microgrid concept was developed within the framework of the European project "MICROGRIDS – Large Scale Integration of Microgeneration to Low Voltage Grids" hereafter called the MicroGrids project.

According to Lopes *et al.* [4], a microgrid can be defined as an LV distribution system to which small modular systems are to be connected. In this sense, a microgrid corresponds to an association of electrical loads and small generation systems through an LV distribution network. This means that loads and sources are physically close so that a microgrid can correspond, for instance, to the network of a small urban area, to an industry or to a large shopping centre. Apart from an LV distribution network, microgeneration devices and electrical loads, a microgrid may also include storage equipment, network control and management systems and heat recovery systems (CHP applications). It is also assumed that the microgrid can be operated in two main situations:

- **Normal Interconnected Mode** – The microgrid will be electrically connected to the main MV network either being supplied by this network totally or partially or injecting power into the main MV grid.
- **Emergency Mode** – In case there is a failure in the main MV network, the microgrid must have the ability to operate in an isolated mode, *i.e.* to operate in an autonomous way similar to the power systems of geographic islands.

In short, a microgrid is a new type of power system comprising LV grids with small modular generation sources which can be connected to the main power system or be operated autonomously.

Depending on the primary energy source used, on the microgenerator dimension and on the type of power interface, these microsources can be considered as non-controllable, partially controllable and controllable. To the utility, the microgrid can be seen as a controlled cell of the power system. To the customer, it can be designed to meet his special needs and provide additional benefits such as improved power quality and reliability, increased efficiency (through CHP applications) and local voltage support.

2.2.3.1 Control and Management Architecture

The architecture of the microgrid concept from the MicroGrids project is presented in Figure 2-5.

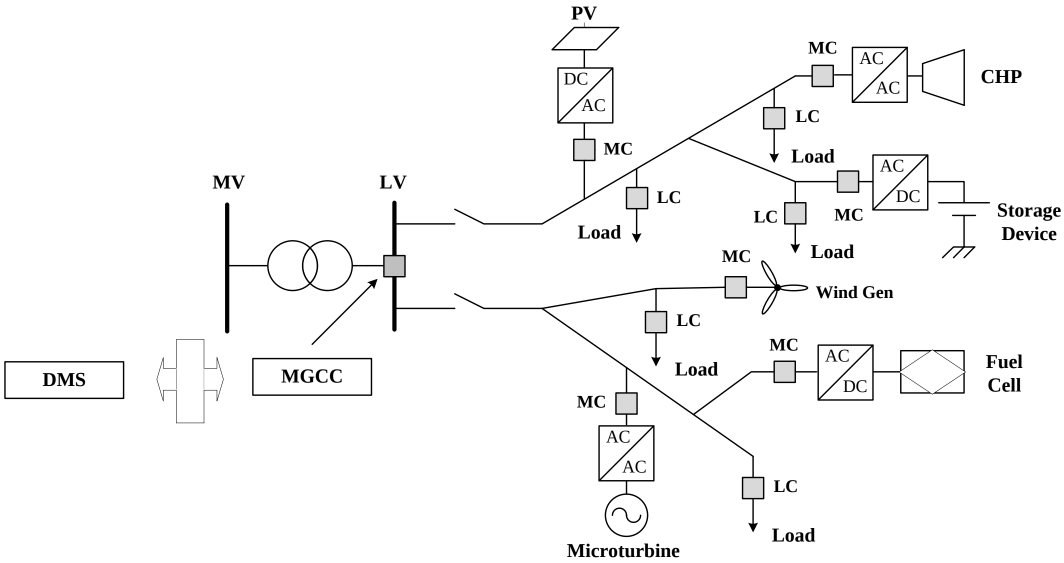

Figure 2-5 – “MicroGrids Project” Microgrid Architecture (adapted from [4])

This microgrid includes several feeders supplying electrical loads, several microgenerators (such as a PV system, a CHP system, a wind generator, a fuel cell and a microturbine), a storage device (*e.g.* flywheel) and several control and management equipments.

Firstly, the microgrid is controlled and managed by an MGCC, installed on the LV side of the MV/LV substation. The MGCC has a number of crucial functions and can be seen as the interface between the microgrid and the main distribution network. At a second hierarchical level, each microgeneration and storage device is locally controlled by an MC and each electrical load is locally controlled by a Load Controller (LC). In order to be able to ensure proper operation of the whole system, communication between two sets of devices is required:

- The LC and MC, as interfaces to control loads (through the application of an interruptibility concept) and as microgeneration active and reactive power production levels, respectively;
- The MGCC, as central controller that aims at promoting adequate technical and management policies and providing set-points to both LC and MC.

Simultaneously, it is expected that the MGCC will be able to establish some type of communication with the DMS, located upstream in the distribution network, thus contributing to an improvement in the management and operation of the MV distribution system.

Regarding the MGCC, its main functions are:

- <u>During normal interconnected mode</u> – the MGCC collects data from microsources and loads in order to automatically perform a number of operations such as forecasting studies, economic scheduling of microgeneration, security assessment evaluations, DSM functions and interface with the DMS.
- <u>In emergency mode</u> – a change in the output power control of the microgenerators is required since they change from a dispatched power mode to a frequency control

mode in the isolated grid. In such an event, the MGCC reacts as a secondary control loop. It is also important for the MGCC to have accurate knowledge of the type of loads in the grid (to eventually adopt interruption strategies) and to use support from storage devices. As a whole, the MGCC is also responsible for local black start strategies. The black start function ensures an important advantage of microgrids in terms of improving reliability and continuity of service, by reducing interruption times.

The MC and LC are local controllers aiming at contributing to the economic scheduling activities, to local control of storage devices, to load tracking activities and to manage loads with interruption or peak shaving capabilities. At an advanced stage, the microgeneration and loads will be fully integrated in electricity markets and local controllers will be in charge of preparing selling and buying offers to communicate to the MGCC.

As previously stated, this control architecture must rely on a communication system the main function of which is to allow the MGCC to be able to coordinate all microsources and controllable loads, through their corresponding local controllers. Since these controllers have a degree of autonomy and the MGCC is used primarily for optimizing operating conditions (in normal interconnected operation), fast communications are not required. Therefore, a communication solution based on narrow-band Power Line Carrier[16] (PLC) may be adequate, especially given the small geographic-span of a microgrid [35].

2.2.4 Advantages and Challenges of Microgrids

The development of the microgrid concept is very promising for the electric power industry as a number of advantages can be foreseen at several levels [4], [28]:

- Environmental issues – the environmental impact of microsources is expected to be smaller than large conventional thermal power stations. Also, the main benefits of the microgrid in this topic are:
    - Physical proximity between consumers and microsources may help increase consumer awareness towards a more rational use of energy.
    - Reduction of GHG emissions that may mitigate the alleged effects of climate change due to the creation of technical conditions to increase the connection of RES at the LV level. This will be achieved by the use of these sources together with storage devices and their efficient coordinated control, both at a local level and at the microgrid level. In fact, RES are characterized by very low emissions and microturbines have also reduced impact due to close control of the combustion process.
- Operation and investment issues – Reduction of both physical and electrical distance between generating units and loads may contribute to:
    - Improvements of reactive support of the whole system, thus enhancing the voltage profile.
    - Reduction of T&D feeder overload.
    - Reduction of T&D losses.

[16] Power Line Carrier is a communication system for carrying data on a conductor primarily used for electric power transmission.

  - Reduction/postponement of investments in the expansion of transmission and large-scale generation systems.
- Quality of service – Improvement in power quality and reliability in particular is achieved due to:
  - Decentralization of supply.
  - Better match of supply and demand.
  - Reduction of the impact of large-scale transmission and generation outages.
  - Minimization of downtimes if microsources are allowed to operate autonomously, namely when there is a disturbance in the upstream distribution system, and enhancement of the restoration process through the black start function of microsources.
- Cost saving – The following cost savings can be achieved in microgrids:
  - Utilization of waste heat in CHP applications. Also, no substantial infrastructure is required for heat transmission since CHP sources are located close to customer loads.
  - Integration of several microsources combined into a microgrid allows sharing generated electricity among the customers, reducing the need to import/export power from/to the main grid through long feeders.
- Market issues – The following advantages can be attained:
  - Possible development of market driven operation procedures of microgrids will lead to a significant reduction of market power exercised by established generation companies. The microgrid can be regarded as an aggregator for individual loads and microgeneration units, enabling them to participate in electricity markets.
  - Microgrids may be used to provide ancillary services.
  - Widespread application of modular microsources may contribute to a reduction in energy price in the power market with appropriate economic balance between network investment and DG utilisation. Further price reduction may be achieved by optimizing microgeneration operation (*e.g.* generating power locally at expensive peak loads and purchasing power from the main grid when economically more attractive).

Conversely, several challenges and potential drawbacks face the development of microgrids as follows:

- High costs of DER – The high installation cost for microgrids is a big disadvantage that may be reduced if some form of subsidies from government bodies is obtained as a device to encourage investment, at least for a transitory period, given the current official environmental and carbon capture goals.
- Technical difficulties – These technical barriers are mostly related to the relative lack of experience and technical knowledge to operate and control a significant number of microsources. This aspect requires extensive real-time and off line research on issues such as management, protection and control of microgrids. Also, specific telecommunication in infrastructures and communication protocols need to be developed to help managing, operating and controlling the microgrids. In addition,

economic implementation of seamless transition between operating modes is a major challenge since the currently available solutions are still quite expensive. However, some of these technical difficulties are in the way of being overcome as more research and demonstration projects are being set up across Europe, the USA and Asia [36].

- Absence of standards – Since this is a comparatively recent area, standards are not yet available for addressing power quality, operation and protection issues, for instance.
- Administrative and legal barriers – In some countries, there is a lack of legislation and regulations for the operation of microsources. However, in Portugal there is already specific legislation addressing the connection of microgeneration to the grid that establishes the tariffs to be paid to microgeneration, adopting an avoided cost strategy leading to subsidised tariffs[17]. Naturally, legislation and regulation for microgrid operation is more complex and will have serious implications regarding coordination with the distribution company on issues such as dispatch voltage/var control strategies, real time management, ancillary services provision, *etc.*

2.2.5 The Microgrid in the General Smartgrid Concept

Following the change of paradigm in electrical power systems, there has been a growing awareness, within the electricity supply industry, of the need to reinvent electricity networks. With the advent of new technologies for generation, networks, energy storage, load efficiency, control and communications, as well as with the arrival of liberalised markets and environmental challenges, it is necessary to have a shared and strategic vision for the electrical power system. This is seen as the way to ensure that the networks of the future can meet the future needs of customers and a have broader range of stakeholders.

The active networks of the future will efficiently link small and medium scale power sources with demand, thus enabling efficient decisions on how best to operate in real-time. The level of control required to achieve this aim is significantly higher than that found in the present transmission and distribution systems. Power flow assessment, voltage control and protection require cost-competitive technologies and new communication systems with more devices such as sensors and actuators than are presently used in distribution systems. In order to manage active networks, the vision of grid computing should be adopted, which assures universal access to resources. An intelligent grid infrastructure will provide more flexibility concerning demand and supply, providing at the same time new tools for optimal and cost-effective grid operation. Intelligent infrastructure will enable sharing of grid and ICT resources including ancillary services, balancing and microgrids behaving as a Virtual Power Plant[18] (VPP) [37].

According to Pudjianto *et al.* [38], the microgrid and the VPP concepts can be regarded as vehicles to facilitate cost-efficient integration of DER into the existing power system. Through

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[17] As of the 2nd November 2007, according to the Portuguese Decree-Law nº 363/2007 from the Ministry of Economy and Innovation.

[18] The concept of VPP was developed to enhance the visibility and control of DER to system operators and other market actors by providing an appropriate interface between these system components. For more information see http://www.fenix-project.org/

aggregation, DER access to energy markets is facilitated and DER-based system support and ancillary services can be provided.

Following these developments, the need arose for a coherent approach to the topic of smartgrids and, in 2005, the SmartGrids European Technology Platform for Electricity Networks of the Future[19] was established in order to meet the challenges seen by network owners, operators and particularly users, across the EC. The main aim of the SmartGrids Platform is to formulate and promote a vision for the development of European electricity networks looking towards 2020 and beyond.

According to [39], a smartgrid is an electricity network that can intelligently integrate the actions of all users connected to it – generators, consumers and those that do both – in order to deliver efficiently sustainable, economic and secure electricity supplies.

A smartgrid employs innovative products and services together with intelligent monitoring, control, communication and self-healing technologies in order to:

- Better facilitate the connection and operation of generators of all sizes and technologies;
- Allow consumers to play a part in optimizing the operation of the system;
- Provide consumers with greater information and choice of supply;
- Significantly reduce the environmental impact of the whole electricity supply system;
- Deliver enhanced levels of reliability and security of supply.

Smartgrids deployment must include not only technology, market and commercial considerations, environmental impact, regulatory framework, standardization usage, ICT and migration strategy, but also societal requirements and governmental edicts.

In the future, the operation of power systems will be shared between central generation and DG. Control of DG could be aggregated to form microgrids or VPPs in order to facilitate their integration both in the physical system and in the market. As seen above, a microgrid can be regarded, within the main grid, as a controlled entity operated as a single aggregated load or generator and, given attractive remuneration, as a source of power or of ancillary services supporting the main network. An overview of the future of power systems according to the smartgrid paradigm is shown in Figure 2-6.

The deployment of smart metering can be seen as a means of pushing forward the development of the smartgrid concept by providing the infrastructure to support advanced control and management functionalities within the distribution system.

Of course, there are still significant technical and commercial challenges that have to be addressed in order to achieve active distribution network operation and its coordinated control with the upstream conventional networks.

[19] The European Commission Directorate General for Research developed the initial concept and guiding principles of the Technology Platform with the support of an existing FP5+6 research cluster, which represents over 100 stakeholders in the electricity networks sector.
For more information see http://www.smartgrids.eu/

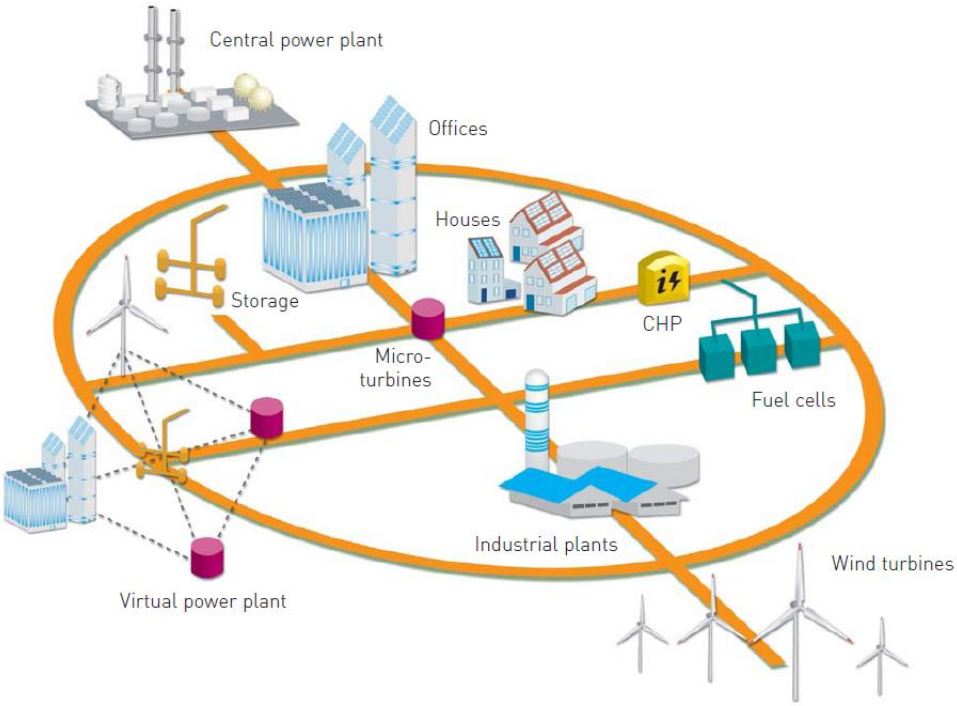

Figure 2-6 – Smart Power Networks [40]

2.3 Voltage Regulation

2.3.1 Introduction

Distribution systems, whether of the radial type found in rural or suburban areas or of the meshed type found in urban areas, are generally designed to operate without any generation within the distribution system or at customer loads. The introduction of generation sources on the distribution system can significantly impact the flow of power and voltage conditions at customers and utility equipment. These impacts may be either positive or negative, depending on distribution system operation and DG characteristics.

Radial distribution systems are usually regulated using OLTC transformers at substations, supplementary line regulators on feeders, and switched capacitors on feeders. Through the application of these devices customer service voltages are usually maintained within the pre-defined allowed limits. Voltage regulation practice is based on radial power flows from the substation to the loads and DG introduces "meshed" power flows that interfere with the effectiveness of standard voltage regulation practice [41].

Since it is an obligation of the distribution utility to supply its customers at a voltage within specified limits, the design of distribution circuits is critical and has direct implication on the costs, which lead to the development of several techniques aiming at achieving the maximum use of these circuits. The voltage profile of a typical radial distribution feeder is presented in Figure 2-7. Even though different voltage levels are used in each country, the principle of operation still holds.

Figure 2-7 shows that the ratio of the MV/LV transformer was adjusted by changing the taps off-line in order to ensure acceptable voltage at maximum load for the most remote customer.

It can also be seen that, during minimum load, the voltage received by the customers is below the maximum allowed. However, if a DG unit is connected to the end of the feeder, the flows in the circuit will change and, consequently, so will the voltage profiles. The most challenging situation occurs when the customer load is at a minimum and the output of the DG unit must flow back to the source. In this case, for a lightly loaded distribution network, the approximate voltage rise (ΔV) due to the presence of the DG unit can be given (in per unit – p.u.) by:

$$\Delta V = \frac{(P \cdot R + X \cdot Q)}{V} \tag{2-1}$$

Where

P is the active power output of the DG unit
R is the reactive power output of the DG unit
X is the resistance of the circuit
Q is the inductive reactance of the circuit
V is the nominal voltage of the circuit

From (2-1) it is possible to observe that both active power and reactive power influence the voltage magnitude.

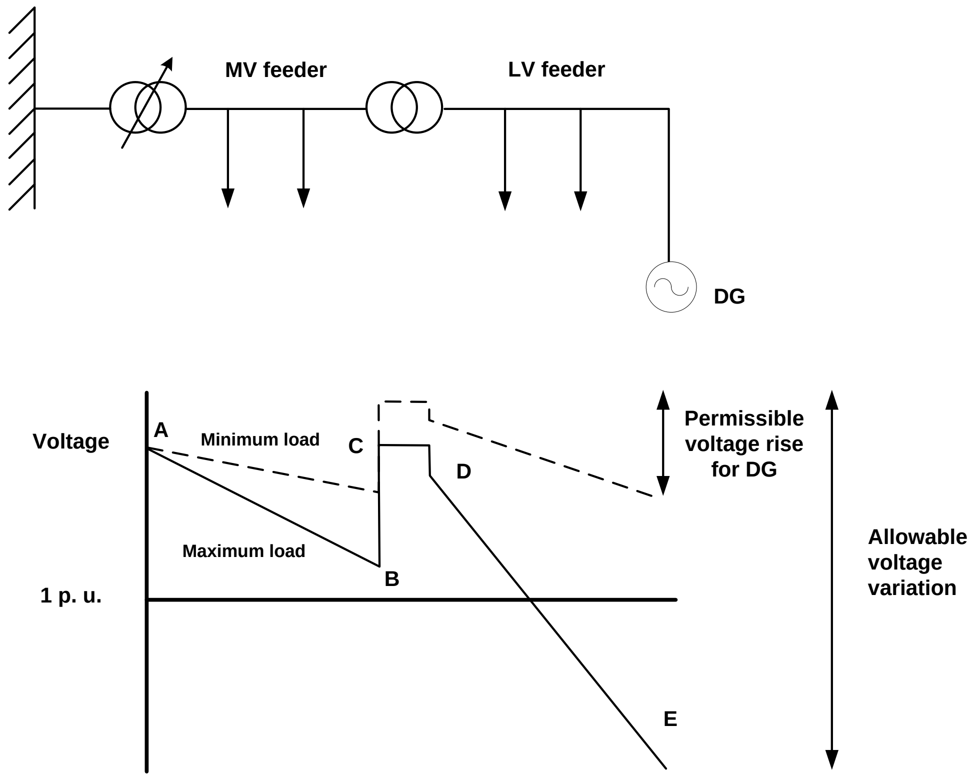

Figure 2-7 – Voltage Variation down a Radial Feeder (adapted from [7])

The points and line segments shown in Figure 2-7 are:

A Voltage kept constant by HV/MV distribution transformer tap-changer
A–B Voltage drop in the MV feeder due to the loads
B–C Voltage increase due to taps in the MV/LV distribution transformer tap-changer
C–D Voltage drop in the MV/LV distribution transformer
D–E Voltage drop in the LV feeder due to the loads

In some situations, this voltage rise effect can be limited by reversing the reactive power flow and/or operating at leading power factor. This may be effective on MV overhead circuits since these usually have a high X/R ratio, *i.e.* have inductive reactance dominant over resistance. However, on LV distribution circuits, the dominant effect is that of the active power (P) and of the network resistance (R) which usually leads to having only small DG units connected to LV networks. In fact, this voltage rise effect is usually a limiting factor for DG connection to the distribution grid. Design rules to define the maximum allowable DG capacity vary from country to country and tend to be rather restrictive [7].

2.3.2 Voltage Control in Distribution Networks with Distributed Generation

As said above, the connection of DG may alter significantly the operation of the distribution network and create a variety of well-documented impacts with voltage rise being the dominant effect, particularly in rural networks [42]. This type of network uses mostly overhead lines for long radial feeders that are scattered across the land in order to reach isolate customers.

In fact, in order to export its power, a DG unit is likely to have to operate at a higher voltage than the primary substation unless it is able to absorb a significant amount of reactive power. This is especially true in networks with low X/R ratio [42].

Normally, without DG, there would be voltage drop across the distribution transformer and the feeders downstream so that voltage at the customer side would be less than the voltage at primary side of the transformer. The presence of the DG introduces reverse power flow to counteract this normal voltage drop, sometimes even raising voltage, and the voltage may actually be higher at the customer side than on the primary side of the distribution transformer, exceeding the maximum limit allowed.

Figure 2-8 shows the effect of DG in an LV given several scenarios of DG penetration. It can be observed that voltage may rise above admissible limits if there is high DG penetration, where DG is forced to export its power to the upstream MV network. Consequently, some degree of coordination with the tap setting of HV/MV transformer is required, in order to ensure that voltage does not rise above the pre-defined limits.

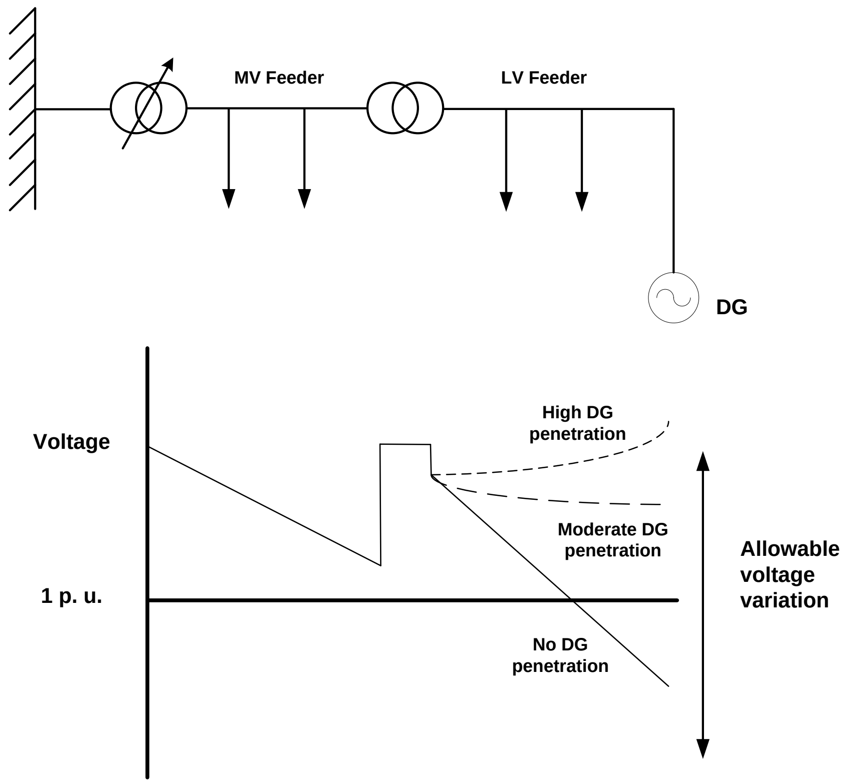

Figure 2-8 – Voltage Variation down a Radial Feeder for Several DG Penetration Scenarios

Therefore, the voltage rise effect can be a major concern when connecting DG to the distribution system. Due to operational issues, most DSOs require that DG operate at zero reactive power or at a fixed power factor. This limits the amount of DG installed capacity in order to guarantee admissible voltage profiles in the worst case scenario. One of the main reasons for this policy has to do with the fact that certain types of DG automatic voltage control may interfere with traditional DSO control, namely using OLTC transformer operation. In fact, the maximum allowable DG capacity connection is usually calculated based on deterministic procedures and assuming the worst case scenario, *i.e.* maximum substation voltage, minimum network loading conditions and maximum DG output power [43]. Nevertheless, the simultaneous occurrence of all these conditions is not likely, which means that there is considerable room for improvement, if appropriate control actions are developed for network operation.

Consequently, in order to increase the maximum allowable DG connection capacity, strategies able to control the voltage rise effect must be employed [44]. Basically, three main approaches can be found in the available technical literature: local distributed voltage control, centralized voltage control (active network management) and generation curtailment [45], [46].

Distributed control can be achieved by not enforcing unity power factor and allowing DG to manage its reactive power output (either injecting or absorbing). This voltage control mode may be employed when voltage limits are overstepped and help reducing the voltage rise effect, thus allowing more DG to be connected to the network. Alternatively, when voltage is within limits, power factor control can be used. Of course, the reactive power control capability of DG depends on its network interface. For instance, power electronic interfaces are capable of controlling their active and reactive power independently as long as their operational limits are not exceeded [46].

On the other hand, centralized voltage control is based on information about a large part or even the whole distribution network in order to determine the control actions to be performed. Typically, these methods regulate not only substation voltage and DG reactive power but also other components with voltage control capability such as capacitor banks, Static var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), *etc.* Usually, network voltages either measured or estimated are required as well as precise information on the state of the network. Although much of this information is not fully available at the present time, in a near future it may be possible to obtain relevant data by means of the deployment of smart metering infrastructures, for instance.

One basic difference between distributed and centralized control is that centralized control relies on communication, sensors and advanced control systems but is able to ensure coordinated and optimized management of the available resources for voltage control whilst decentralized control is simpler to implement (less communication needed as mostly local data is used) but lacks coordination between devices and will lead to sub-optimum solutions.

Finally, active power generation curtailment (shedding) can also be exploited as a means of reducing the voltage rise effect. This can be done by reducing the active power output of DG, *i.e.* disconnecting a required number of generating units when voltage exceeds its limits [46]. This kind of control is particularly suitable for DG whose output depends on some external factor such as wind speed or solar irradiance for wind generators or PV panels, respectively.

Vovos *et al.* [45] compare two versions of the centralized and distributed approaches using an Optimal Power Flow (OPF) and conclude that both strategies give similar results in terms of the potential for connecting increased capacities within existing networks. Furthermore, and although they consider that both methods are better than strict power factor control by the DSO in terms of exploiting existing capacity in the network, they also document a negative impact on losses, which may increase substantially.

Concerning the decentralized voltage control, an approach based on power factor regulation is presented by Paraskevadaki *et al.* in [47]. In this paper, the impact of various power factor regulation methods, using constant output power factor and regulated output power factor, is evaluated for DG sources (mainly PV units) connected to the LV level. The authors conclude that the approach based on maintaining a constant capacitive power factor achieves best results. Another similar method applied to the case of PV generation is presented in [48]. In this case, a voltage regulation method for PV connections using reactive power proportional to global irradiance is proposed.

A different approach, by Carvalho *et al.* [43], proposes a distributed automatic control approach to alleviate the voltage rise caused by active power injection from DG. The objective of this approach is not to control bus voltage but rather to ensure that DG active power injections do not cause significant voltage rise. The authors also compare the reactive power control approach to constant power factor approaches. Finally, they conclude that the reactive power control relationship with OLTC transformer control increases stress in tap changing when compared to a constant power factor approach.

Kiprakis *et al.* [49] present a proposal for an automatic voltage/power factor controller in rural networks with increasing capacity of DG based on synchronous generators. It is basically a deterministic approach that is able to switch between voltage and power factor control modes, according to a pre-defined set of rules. In addition, the same authors also propose an alternative approach based on a fuzzy inference system that is able to adjust the reference setting of an automatic power factor controller in response to terminal voltage values.

A more centralized approach based on active voltage level management of distribution networks with DG is presented by Kulmala *et al.* in [46]. They developed an algorithm which controls the set-points of Automatic Voltage Regulators (AVRs) relays based on maximum and minimum voltages in the network.

Lopes *et al.* [50] address the feasibility of using DG for voltage and reactive power control by taking profit of the control capabilities of different technologies such as DG units, transformer taps and capacitor banks. In order to do that, they formulate an optimization problem with the objective o minimizing active power losses through a meta-heuristics known as Evolutionary Particle Swarm Optimization (EPSO). A similar approach based on genetic algorithms is presented in [51].

Other approaches to voltage control can also be found in [52], [53] and [54].

A considerably different alternative is the use of Multi-Agent Systems (MAS) that can be applied to power systems in general and to voltage control in particular. MAS can be used for several power engineering applications as they have specific characteristics that are well suited for some issues such as distributed control [55], [56]. In fact, with the introduction of DG, load control, market operation, *etc.* the complexity of the power system grows considerably. MAS are able to deliver a technology to flexibly control modern power systems since it can provide intelligent, fast and adaptable local control and decision making capabilities [55]. Applications of MAS include power system restoration, active distribution networks operation and microgrid control.

Baran *et al.* [57] suggest a MAS scheme to solve an optimization problem: dispatching DG for voltage support in distribution feeders. They state that the characteristics of the MAS approach may facilitate plug-and-play integration of DG and the approach is able to coordinate reactive power dispatch among DG units to provide voltage support. In addition, communication requirements are also assessed and said to be quite modest.

2.3.3 Control of Power Electronic Interfaced Distributed Generation

As previously seen, many DG sources may use a power electronic interface when connecting to the distribution system. Therefore, several approaches for the control of DG units exploiting the capabilities of their power electronic interfaces have been developed, some of which are described next.

Engler [58] proposes an approach using frequency and voltage control droops for inverters in interconnected operation. The concept uses active power/frequency droops and reactive power/voltage droops for inverter control, similar to those in utility grids, shown in Figure 2-9.

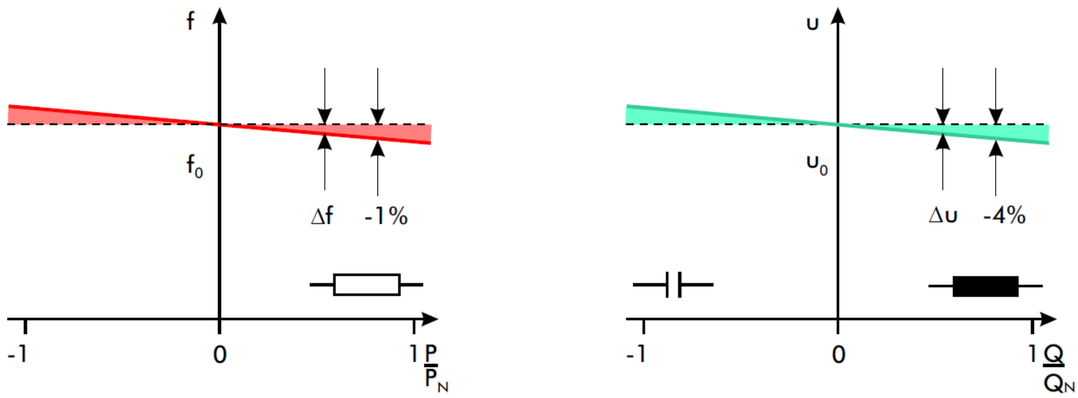

Figure 2-9 – Active Power/Frequency and Reactive Power/Voltage Droops [58]

Using this approach, the supervisory control just needs to provide parameter settings for each component, including the idle frequency, the idle voltage and the slopes of the droops. This strategy has several advantages such as:

- Simple expansion of the system;
- Increased redundancy;
- Simplified supervisory control;
- Absence of fast communication requirements.

An application of these principles to the case of AC coupled PV hybrid systems is presented in [59]. In this paper, two inverters are presented (PV-inverter Sunny Boy© and battery inverter Sunny Island©[20]) implementing these new control concepts for hybrid microgrids containing PV units, wind turbines, diesel gensets and batteries.

In [31], the authors propose novel active and reactive power management strategies for inverter interfaced DG in autonomous operation. The method presented uses only information available at the terminals of the inverter interfaced DG units and, as a result, does not require communication between the devices. The proposed active and reactive power management strategies provide active and reactive power set-points for each DG unit in order to:

- Ensure load sharing among DG units in autonomous operation;
- Maintain power quality in terms of voltage profiles and harmonic distortion;
- Improve dynamic response, maintaining stability and ensuring voltage and frequency restoration during and after transients.

They developed a power management system that includes a real power generation controller that determines the real power output of the unit based on frequency variations at the PCC of

[20] Both inverters were developed in cooperation by Fraunhofer IWES (previously *Institut für Solare Energieversorgungstechnik* – ISET) and SMA Solar Technology AG, Germany and are produced by SMA. For more information see http://www.sma.de/en.html

the DG unit. It comprises a frequency droop characteristic and a frequency restoration algorithm.

Moreover, a reactive power control block is included. In this case, the authors propose three possible schemes for reactive power management:

- Voltage-droop characteristic – the droop characteristic is used to determine the reactive power reference, thus ensuring that reactive power injection varies according to node voltage variations.
- Voltage regulation – reactive power injection is regulated in order to maintain the node voltage where the DG unit is connected at a certain level (*e.g.* 1 p.u.).
- Power factor correction – the DG unit reactive power injection is controlled in order to improve the power factor or to meet the reactive power requirements of the load connected to the same bus.

Also, based on the droop related concepts, Lopes *et al.* [30] focus on the modelling of power electronic interfaces and corresponding control requirements in cases where there are no synchronous generators directly connected to the grid. In this work, two kinds of control strategies are proposed to operate an inverter. The inverter model is derived according to the following control strategies:

- PQ inverter control – the inverter is used to supply a given active and reactive power set-point.
- Voltage Source Inverter (VSI) control – the inverter is controlled to "feed" the load with pre-defined values for voltage and frequency. Depending on the load, the VSI real and reactive power output is defined.

The PQ inverter is implemented as a current controlled voltage source and, given its intrinsic characteristics, it is more suitable for interfacing renewable based DG such as PV or wind generation.

VSI control is especially important in autonomous operation since the inverter emulates the behaviour of a synchronous machine, controlling both frequency and voltage through droops, according to the following equations:

$$\omega = \omega_0 - k_P \cdot P \qquad \textbf{(2-2)}$$

$$V = V_0 - k_Q \cdot Q \qquad \textbf{(2-3)}$$

Where

ω is the angular frequency
ω_0 is the idle value of the angular frequency
k_P is the active power/frequency droop slope
P is the inverter active power output
V is the voltage
k_Q is the reactive power/voltage droop slope

V_0 is the idle value of the voltage
Q is the inverter reactive power output

The VSI inverter is usually coupled to controllable sources with fast responses (such as microturbines) or to storage devices (*e.g.* flywheels).

2.4 Ancillary Services

2.4.1 Introduction

Controlling both frequency and voltage has always been a critical task in operating an electrical power system. Nevertheless, following the liberalization of the electricity sector, the resources available to realize this control are no longer in the hands of one same company: there is a need for the System Operator (SO) to obtain these services from other industry participants.

Furthermore, since the liberalization process has progressed independently in several regions of the world and each power system has its own specific characteristics, technical definitions for these services vary considerably. Therefore, ancillary services have been defined differently, depending on the electrical system and on the regulatory framework in which they are implemented [60], [61].

As there are diverse definitions of ancillary services, different ancillary services are considered for each electrical system.

In [62], a general definition of ancillary services is presented. According to the Union of the Electricity Industry (EURELECTRIC) [21], ancillary services are those services provided by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser. These services are required to ensure that the SO meets its responsibilities in relation to the safe, secure and reliable operation of the interconnected power system. The services include both mandatory services and services subject to competition.

The SO manages the ancillary services as follows:

- Obtains contributions ("elementary" ancillary services) from service producers (some of which follow from regulatory or contract obligations);
- Carries out the technical management of the system, while making sure there is a suitable level of security;
- Adds its own share (implementation of controls, load dispatching function) and thus elaborates the final system services;
- Provides the consumers with the system services.

[21] EURELECTRIC is the sector association which represents the common interests of the electricity industry at pan-European level, plus its affiliates and associates on several other continents. EURELECTRIC's mission is to contribute to the development and competitiveness of the electricity industry and to promote the role of electricity in the advancement of society.
For more information see http://www2.eurelectric.org/Content/Default.asp

As previously mentioned, the services provided differ according to the particular definition of ancillary services. Nevertheless, some main services may be grouped into the following categories [61]:

- Frequency control – services related to the short-term balance of energy and frequency of the power system; it includes primary frequency regulation and operational reserves.
- Coordination and operation – services related to quality of the supply apart from the frequency of the system; it includes scheduling and dispatch, congestion management and voltage control and reactive power supply.
- System backup and restoration – services related to the backup capacity of the system and the ability to return to normal operation after a blackout has occurred; it includes black start capability and supplementary reserve.

In [60], a common framework is proposed based on the one used by the Union for the Co-ordination of Transmission of Electricity (UCTE)[22]. The UCTE establishes the security and reliability standards for the interconnected synchronous system of mainland Europe. Its activities are similar to those of the North American Electric Reliability Council (NERC)[23]. However, like NERC, the UCTE is not a system operator and hence does not intervene in the operational working of the system.

Rebours *et al.* [60] and [63], perform a survey of ancillary services in several systems, focusing on frequency control services and voltage control services. This work addresses the main technical and economic features of these two services on several systems.

2.4.2 Ancillary Services from Distributed Generation and Microgrids

As seen previously, as DG penetration increases, it becomes economically interesting to have DG participating in the provision of ancillary services, required for a secure and reliable operation of the power system, due to two main reasons: 1) if DG only displaces energy from central generation without bringing additional capacity and flexibility, the overall operation cost will rise and 2) the possibility of DG supplying ancillary services may turn some DG projects economically feasible [5].

Many papers can be found in the available technical literature that emphasize the role of DG in ancillary services provision [5], [10], [64], [65].

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[22] As of July 2009, the work of UCTE has been fully integrated into the European Network of Transmission System Operators for Electricity (ENTSO-E), which is an association of Europe's TSOs.
For more information see http://www.ucte.org/ and http://www.entsoe.eu/

[23] NERC is a self-regulatory organization subject to oversight by the U.S. Federal Energy Regulatory Commission, which granted it the legal authority to enforce reliability standards with all U.S. users, owners and operators in order to ensure the reliability of the bulk power system in North America.
For more information see http://www.nerc.com/

According to [5], some services for which potential arrangements can be explored are:

- Transmission System Operator (TSO) frequency response – It is unlikely that TSO frequency response services will be provided regularly by renewable generation, however Combined Cycle Gas Turbine (CCGT) plants located at the distribution side can provide this service. In addition, large wind farms connected to the distribution system may also contribute following technical requirements [5].
- TSO regulating and standing reserve – The key differences between frequency response and reserve services are related to the timescale (typically, reserve services involve longer times). It is unlikely that synchronised reserve will be provided by renewable generation but non-renewable DG already provides standing reserve services to the TSO. Increased DG participation could be facilitated by expanded aggregation services.
- TSO reactive power – Reactive power at lower distribution voltages may effectively displace reactive power from transmission-connected generation. DG connected at these levels can make a significant impact on the amount of reactive power exchanged between the transmission and distribution systems.
- DSO security of supply contributions – The value of security provided by non-intermittent DG may be related to the avoided or deferred costs of network reinforcement. DG can also substitute for network automation facilities, which is particularly relevant when considering the contribution of intermittent generation such as wind.
- DSO quality of service – In the future, there could be opportunities for DG to improve quality of service especially in LV and MV networks, given the contribution of such networks to reliability. A key requirement for DG to reduce the impact of outages will be the ability of islanded operation.
- DSO voltage and power flow management services – DG may provide important services (*e.g.* voltage support or flow control) especially in stressed conditions, where non-intermittent DG would be suitable for such applications. Opportunities may improve with increased DG penetrations due to the higher collective availability.

The potential of DG to provide ancillary services is detailed in [64]. According to the authors, DG systems equipped with appropriate power electronic interfaces are able to perform functions other than the supply of active power to the grid. The services that can be provided include reactive and power flow control and power quality improvements in terms of voltage sag compensation and harmonic filtering. In this case, the use of a DC/AC self commutated Pulse-Width Modulation (PWM) inverter is suggested, given the speed of response and flexibility of this type of device, particularly when compared to conventional synchronous and induction generators. These inverters may be coupled to several types of DG sources such as microturbines, wind turbines, PV systems and fuel cells. Also, Kueck *et al.* [65] agree that power electronic interfaces will enable ancillary services (reliability services) such as reactive power compensation and frequency and voltage regulation.

In [65], the authors state that one of the most exciting prospects of the distribution system of the future will be its ability to provide ancillary (reliability) services. In a near future, these services will be supplied in response to market signals and may be contracted over the

Internet. It is considered that both loads and DG will be able to supply these services since supplying the services locally is usually more efficient than supplying them from distant generating units. In addition to an intelligent distribution system, an automated market system will also be necessary to make this happen.

Furthermore, and although some technical barriers may discourage it, the microgrid can also serve as a small source of power or ancillary services [4], [33]. The possible development of market-driven operation may lead to the reduction of market power of already established generation companies and to the possible contribution of the microgrid to the provision of some ancillary services. The benefits that the microgrid could offer to the distribution system are congestion relief, postponement of new generation or delivery capacity, response to load changes and local voltage support [33].

In fact, many publications can be found that address the opportunity for microgrids in providing ancillary services [4], [28], [29], [33], [66], [67].

For instance, Chowdhury *et al.* [28] state that, although traditionally ancillary services were provided by the supply authority itself, in a re-regulated regime these may be provided by both supply authorities and microgrid owners. In fact, both of them would be able to participate in the ancillary services market, which could result in a series of benefits:

- As energy and ancillary services market prices may vary considerably in time, microgrids could make more profit by selling their energy and ancillary services during high-price periods.
- If microgrids are allowed to sell ancillary services in the open competitive market, by unbundling these services from central power utility, it would expand the market supplies, which might then lead to reduced electricity prices and better economic efficiency.
- Combined market participation of microgrids and system operators as both suppliers and consumers would help to enhance fairness and facilitate better resource utilisation.
- Providing active/reactive power support consumes a considerable amount of generating capacity of the utility generators. If microgrids are encouraged to provide these services at distribution level, then the utility generators can be used to their full capacity for generating electricity.
- Smaller microsources may be able to respond more rapidly to control centre requests than large generators while providing the ancillary services. This would aid in overcoming eventual communication and control delays.
- An aggregate of facilities such as small-building owners and operators may be a more reliable supplier of ancillary services than utility generators since each facility would supply only a small fraction of the total system requirement for each service and the failure of any single resource would have a less significant impact.
- Although the aggregated resources in microgrids may have common-mode failures, it is should be easier and cheaper to build redundancy in microgrids than in a big generating plant.

Therefore, microgrids might participate in open market as both suppliers and customers of electricity services, leading to overall improvement in resource utilisation. This would bring significant benefits to the main power utility, whereby the central generators would be able to generate electricity freely without having to provide the ancillary services [28]. Some ancillary services that may be provided by microgrids include [28], [67]:

- <u>Reactive power and voltage control</u> – The market participation of a microgrid in reactive power and voltage control depends on their size and location. A microgrid may perform smooth voltage regulation locally in response to controller settings, which can be especially interesting during voltage sags if microsources are able to supply reactive power. Moreover, local supply of real and reactive power from microsources significantly reduces feeder losses. For power utilities, reactive power and voltage control is generally accomplished at the cost of generating capacity. However, if microgrids are allowed to provide this service, it might help utility generators to generate at their maximum capacities, thus enhancing overall generation efficiency.
- <u>Frequency response and supply of reserves</u> – Microgrids may offer three ancillary services: frequency responsive spinning reserve, supplemental reserve and backup supply. These services are aimed at restoring the energy balance between generation and load, following a sudden contingency. Microgrids can effectively reduce loads or increase generation by selling these ancillary services to the market. However, these services require suitable communication and control systems since they have different response times and duration requirements. Concerning spinning reserve, microsources will be able to provide this reserve due to their fast response times to system frequency deviation. Regarding supplemental reserve, microgrids can provide this service by making their microsources respond upon a request from the SO [30]. Finally, in respect to backup supply, microgrids can provide this following some prior arrangement made with the SO, which should plan ahead how to use this service for maintaining supply to priority and non-priority loads during supply failures.
- <u>Regulation and load following</u> – Microgrids can efficiently provide the regulation and load following ancillary services for accommodating temporary load variations. These services can be supplied by the microsources that are normally connected to the grid and at the same time located close to the loads, which may help avoiding physical and economic transmission limitations when importing power.
- <u>Black start</u> – After a general blackout, the SO may use communication to trigger a black start sequence. Microgrids can contribute to this following a bottom-up approach, creating small islands that can be later reconnected to the main system based on microsources with black start capability [17], [68].
- <u>Network stability</u> – Microgrids are capable of sensing low-frequency oscillations and provide adequate damping, by making the microsource supply power at 180^{o} out of phase from the oscillation. The damping effect would become more prominent if a large number of microgrids are aggregated to provide this service [28].

Despite what was presented, there is still no generalized consensus over the services that may be provided by a microgrid. Firstly because the microgrid cannot be regarded only as a controlled load, able to control its power demand and power factor, but rather as an entity that is able to sell power to the main grid and provide several valuable ancillary services to the utility, with appropriate payment. This possibility is especially interesting under stressed operation.

For example, the possibility of controlling the load leads to excellent control of the customer voltage profile [28]. Thus, the deployment of capacitors for reactive power control at the customer end may be avoided if power is supplied through microgrid. Most ancillary services deal with real-time energy balance between microsources and loads, whereas black start is especially meant for the microgrid itself for sustaining its major loads without any exchange of power with main utility grid. In this case, a major challenge in providing these services is the communication system and its reliability and speed.

In conclusion, distribution systems should take full advantage of the ancillary services provided by microgrids. In future power systems, faster controls may be provided by local MCs, whereas slower ones for transmission and grid management can be provided by the SO. The MCs would control the microgrid voltage and frequency within limits specified by the SO. They would also be able to dispatch ancillary services such as spinning reserve and black start following commands from the SO [28].

2.4.3 Ancillary Services Markets

The importance of ancillary services has been recently recognized, contrary to the general tendency during the past years when these services were largely overlooked [69].

Following the need for improved reliability in electrical supply, several countries have chosen to implement market mechanisms for ancillary services provision, parallel to energy markets. In [61], Raineri *et al.* have studied various power systems and markets (including in Spain, England and Wales, California – USA and the Nordic countries) and realized that in all of them exists an entity dedicated to the operation and coordination of the ancillary services market, which relies on the SO. They also found out that the most profitable services correspond to primary frequency regulation and voltage control (both services are mandatory in most markets analysed). Nevertheless, the provision of other services, without being compulsory, is always present as a possibility.

DG has interest in participating in ancillary services markets in order to get additional incomes just like conventional central generators. However, often DG is not regarded as being able to maintain the "right" level of reliability and quality and, at the same time, being cost competitive.

The general approach for pricing of ancillary service within competitive electricity markets is based on fixed contracts for a certain time period between the SO and the market participants that are able to provide the required ancillary service. The ancillary services are split up into different services, such as frequency control and reserves or voltage control and reactive power management and system restoration and black start. In regards to DG, frequency and voltage control are of particular interest [70].

Also, microgrids need to have full participation in both energy and ancillary services market, though their size and the fact that they are located at the LV level limits their ability to deliver power and services beyond the substation level [28]. Nevertheless, the advantage of on-site microgrids can be utilised with suitable control and protection schemes to provide reliable supply to the sensitive loads.

Aggregators may aid DER investors to participate in the ancillary services market after determining their collective capability to provide each ancillary service at negotiable prices. Afterwards, the aggregators are able to negotiate the price of the ancillary services with the SO in an iterative manner, thus serving as an intermediate between the SO and DER. These aggregators determine the price and committed quantity for aggregation by negotiating with ancillary services market and DER owners. Market provision for ancillary services requires price negotiation through a bidding scheme unlike that in a vertically integrated utility monopoly [28].

Following a decentralized control strategy and in order to facilitate the operation of DER, local markets may be opened for energy and ancillary services. If economically and technically viable, these local or regional markets can be a part of a national wholesale market or can act as independent markets [71], depending on the type of product or service offered.

2.4.3.1 Voltage Support

It is generally recognized that one of the most promising ancillary services that can be provided by DG and microgrids is voltage support. Nevertheless, much work has still to be done regarding a unified framework for reactive power management and corresponding market integration.

Ahmed *et al.* [72], propose a method for the simulation and analysis of alternative reactive power market arrangements based on combined reactive power capacity and energy payments. The value of reactive power support, in terms of both capability and utilization, of each particular generator is quantified using a developed security constrained reactive OPF. The relative competitiveness of participating generators is also assessed for a spectrum of arrangements between a reactive capacity and a reactive utilization based market. Also, the conflicting objectives of the system operator, as a purchaser of reactive power service, and generators, as suppliers of the services, are analysed.

In [73], a framework is proposed for the voltage control and reactive power management ancillary service based on the same two products: reactive power capacity and reactive power use. Under this competitive framework, an original market structure is designed for the reactive power capacity, based on an annual auction. In addition, the use of the capacity is remunerated at a regulated price. In this case, the service providers considered are generators, capacitors, SVCs and STATCOMs.

In [74], an appropriate structure for reactive power management in competitive electricity markets is also proposed. Here, this structure is based on the separation of reactive power management into two distinct time-frames, *i.e.* a reactive power procurement stage carried out on a seasonal basis, and a reactive power dispatch stage that determines the reactive power levels in “real-time”. It is also discussed that a zonal pricing procedure would be the most appropriate mechanism for payment of reactive power services, so that the local nature of reactive power supply can be used to address market power issues. Finally, the need to include reactive power providers other than generators to improve market competition is discussed.

Several designs for competitive markets concerning reactive power and voltage control can be found [75], [76], [77].

In [76], Zhong *et al.* present the design of a localized competitive market for reactive power ancillary services using individual voltage-control areas defined through the concept of electrical distance, which seems adequate since voltage (and voltage control) is predominantly a local issue. The proposed reactive power market is settled based on uniform price auction for each voltage-control area, using a modified OPF model. The authors also compare this formulation with a system-wide reactive power market and conclude that is more interesting to have localized markets. A very similar approach is followed in [77], where a model handles the reactive power management also as a localized problem, which is considered suitable for the development of a local competitive market for this ancillary service. In this work only generators are considered as service providers.

According to [33], the ability of microgrids to participate in grid-scale ancillary services markets will most likely be limited by voltage and losses, but microgrids could still provide some local services, such as voltage support. Nevertheless, the authors feel that creating a market for localized voltage support, or even placing meaningful value on it, seems unlikely at the present time.

2.5 Summary and Main Conclusions

A change of paradigm is taking place in electrical power systems with the growing integration of DG directly connected to the distribution system, especially at the HV and MV levels. There is a wide range of benefits that can be attained from the deployment of DG, ranging from technical and environmental benefits to economic benefits.

From the utility point of view, DG potentially reduces the need for increasing distribution and transmission infrastructures. As DG is located closer to the loads, flows in the transmission and distribution circuits will be reduced, which contributes to reduce network losses and to potentially defer reinforcement or upgrade investment costs.

From the customer point of view, DG may contribute to enhance local reliability by reducing customer interruption times if islanded operation is allowed, reduce GHG emissions, improve power quality by supporting voltage and reducing voltage dips and potentially lower energy supply costs.

With the advent of DG, distribution networks (and DSOs in particular) have a golden opportunity to benefit from the possibilities that this type of units can bring to both planning and operation of the electrical power systems. In order to profit from these capabilities, active network management strategies must be developed and embedded in control centres, moving away from the traditional "fit-and-forget" policy.

Also, the connection of DG directly to the LV level – microgeneration – is expected to rise in a near future, as seen previously, due to the expected increase of PV panels, small solar thermal generators and micro-CHP solutions connected directly at customer sites. In this context, the microgrid concept can be regarded as an integration platform for supply-side (*i.e.* microgenerators), demand side resources (*i.e.* controllable loads) and storage units located in a distribution grid. The main difference between a microgrid and a passive grid with microsources lies mainly in the management and coordination of all available resources. In addition, a microgrid should be capable of handling both normal operation (interconnected to the main power system) and autonomous operation (islanded from the main grid).

The microgrid concept can be integrated within the general framework of the development of an "intelligent network" that is able to fully exploit all resources connected to it – the smartgrid. In this context, smart metering can be used as a key driver for pushing forward the deployment of the smartgrid.

Furthermore, the presence of DG in distribution networks may pose several challenges to the distribution network, which affect significantly the voltage profiles. In particular, given the specific characteristics of LV networks, a voltage rise effect can be observed if a large amount of DG is connected to the grid. In order to address this issue, either a distributed or centralized control approach must be employed. The centralized approach, although being more complex and relying on communication, is able to ensure coordinated action of the several devices at the various levels of the distribution grid.

Finally, one of the most interesting prospects for DG is the possibility of participating in ancillary services provision. In particular, frequency control and voltage support emerge as two of the most important services that can be provided by DG. Thus, the development of a market structure that is able to accommodate all these new agents is a priority in order to fully exploit the benefits resulting from DG integration.

"If I can do that, what can I not do? I tell you I am very subtle.
When you and Adam talk, I hear you say «Why?» Always «Why?»
You see things; and you say «Why?» But I dream things that never were; and I say «Why not?»"

The Serpent talking to Eve in "*Back to Methuselah*" by George Bernard Shaw (b. 1856 – d. 1950)

Chapter 3 – Novel Concepts for Distribution Network Architecture

This chapter aims at studying the adequate way to manage distribution networks where an increased microgrid penetration is foreseen, corresponding to a situation where most of the LV networks turn into active cells – microgrids. Hence, it is assumed that the microgrid concept is to be extended, leading to the development of a new concept – the multi-microgrid. This involves the development of new management and control architectures and the development of new management tools or adaptation of existing ones for the central DMS.

3.1 Introduction

The new operation paradigm in electrical power systems involves a growing penetration of microgeneration in LV networks based on the development and extension of the microgrid concept. Furthermore, MV distribution grids of the future will include a massive penetration of DG and microgrids (which can operate as active cells) that should be managed under a coordinated and hierarchical control approach. This new type of system will be referred to in this work as the multi-microgrid system.

The new concept of multi-microgrids consists of a high-level structure, formed at the MV level, consisting of LV microgrids and DG units directly connected to the MV level on several adjacent feeders. For the purpose of grid control and management, microgrids, DG units and MV loads under active DSM control can be considered as active cells in this new type of network. In this new scenario, the capability of some MV loads to be responsive to control requests under a load curtailment strategy may also be regarded as a way to get additional ancillary services.

Consequently, a large number of LV networks with microsources and loads, that are no longer passive elements, must operate in a coordinated way. This means that the system to be managed increases massively in complexity and dimension, thus requiring a new control and management architecture.

Logically, this new scenario will involve the adaptation of existing DMS tools, as well as the development of new functionalities, that are able to deal with such demanding operating conditions. An effective management of this type of system requires the development of a hierarchical control architecture, where intermediary control will be exercised by a new controller – the CAMC – to be installed at the MV bus level of a HV/MV substation, under the responsibility of the DSO, which will be in charge of each multi-microgrid. In this way, the complexity of the system may be reduced by sharing tasks and responsibilities among several control entities. The CAMC will behave like a small DMS that is able to tackle the scheduling problem of generating units (both DG and microsources) and other control devices installed in the system, under normal and emergency operating conditions. The architecture of this type of system is presented in Figure 3-1.

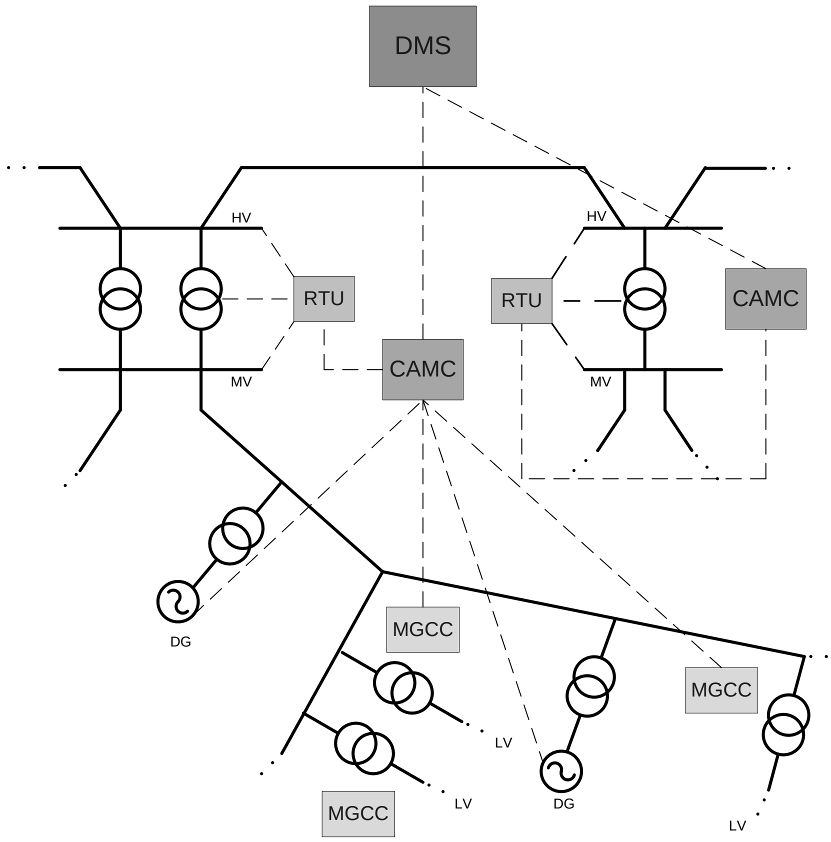

Figure 3-1 – Control and Management Architecture of a Multi-Microgrid System

In this context, the deployment and exploitation of a communication infrastructure as a means of achieving full observability of the distribution network is crucial. This may be achieved by exploiting a smart metering infrastructure, as described in Chapter 2, which will allow coordinated and integrated management of individual active cells such as microgrids (and corresponding microgenerators, loads and storage devices inside the LV network), DG units and loads (under DSM) connected at the MV level, *etc.* This communication infrastructure will be the key driver for managing the distribution network in a more efficient way and, consequently, for maximizing the integration of DG and microgeneration.

3.2 The European Project "More MicroGrids"

As previously mentioned in Chapter 1, the concept of multi-microgrids was developed within the framework of the EU More MicroGrids project.

The More MicroGrids project had a total duration of 48 months, from January 2006 to December 2009. The project was lead by the National Technical University of Athens and comprised 27 partners from 12 European countries, including INESC Porto and EDP Distribuição (the Portuguese DSO) from Portugal, in a consortium that gathered some of the major European manufacturers as well as power utilities as potential microgrid operators and research teams with complementary high level expertise.

This project aimed at analysing the increase of microgeneration penetration in electrical networks through the exploitation and extension of the microgrid concept, which involved the investigation of alternative microgenerator control strategies and alternative network designs, the development of new tools for multi-microgrids management operation (involving DMS architectures and new software adaptation) and the standardisation of technical and commercial protocols. Logically, in all this development, the microgrid concept played a vital role.

The first attempt at the European level to deal in-depth with the development of microgrids was the EU project "MICROGRIDS – Large Scale Integration of Microgeneration to Low Voltage Grids", mentioned in Chapter 2. However, considering future scenarios where a wide deployment of microgrids is foreseen, further issues that still needed to be investigated in-depth have been identified. Consequently, the following scientific and technical objectives were set up:

1. Investigation of new microsource, storage and load controllers to provide efficient operation of microgrids – Transition from interconnected to islanded operation provides challenging frequency control problems. Also, close coupling of active/reactive power in LV networks complicates voltage control. These issues were investigated and solutions were proposed and tested at the hardware level.
2. Development of alternative control strategies (centralized *vs.* decentralized) – Several levels of decentralization can be considered, ranging from a fully decentralized approach to the implementation of a pure hierarchical control system. These issues were analysed and comparatively assessed. In addition, next generation ICT infrastructures were investigated through laboratory testing.
3. Alternative network designs – Inverter-dominated microgrids are not necessarily subject to the same frequency limitations as traditional power systems. The advantages of operation at variable frequencies or even DC microgrids were investigated, as well as the application of modern protection philosophies and modern solid state interfaces and other devices. These novel concepts were evaluated through laboratory testing and validation.
4. Technical and commercial integration of multi-microgrids – Integration of multiple microgrids into the operation of a decarbonised power system, perhaps with millions of active participants, requires radically new structures and practices to make possible the interface with the upstream DMS and the operation of coordinated, but decentralized, markets for energy and services. Specific new software tools and simulation approaches were developed to address this objective.
5. Field trials of alternative control and management strategies – Evaluation of the control strategies developed and laboratory-tested on actual microgrids is clearly needed. In particular, islanded operation is a major challenge. Field tests were undertaken on several test sites in order to examine the performance of various aspects of microgrid operation.
6. Standardization of technical and commercial protocols and hardware – In order to promote a mass scale development of microgrids, it is essential to develop standards of technical and commercial protocols that will allow easy installation of microsources with plug-and-play capabilities. This objective was met by building on established standards, taking into account the particular requirements of a microgrid.
7. Impact on power system operation – The distinctive advantages of microgrids on power system operation regarding increase of reliability, reduction of losses and

environmental benefits were quantified at a regional, national and European level. This will allow the development of evidence-based policy advice concerning the impact of wide implementation of microgrids.

8. Impact on the development of electricity network infrastructures – Large penetration of microgrids will have a massive impact on the future operation and development of electricity networks. Hence, microgrids must become a key part of the overall network reinforcement and replacement strategy of the aging EU electricity infrastructure. New tools and simulation approaches were developed to address this objective and to quantify the overall benefits of microgrids.

There were several innovation-related activities in the More MicroGrids project, namely:

- Experimental validation of microgrid architectures in interconnected and islanded mode, as well as during the transition;
- Development and experimental validation of alternative control concepts and algorithms in actual microgrids;
- Development and testing of DG and intelligent load controllers (power electronic interfaces);
- Development and testing of storage technology systems, able to support microgrid operation during transition to islanded mode;
- Development of advanced protection hardware and algorithms, as well as solid state network components of microgrids;
- Development of control and management algorithms effective operation of microgrids and for interfacing them with the upstream DMS;
- Quantified evaluation of the microgrids effects on power system operation at regional, national and projected European levels;
- Quantified evaluation of the microgrids effects on power system expansion planning at regional, national and projected European level.

In particular, the integration of several microgrids in MV operation needed to be carefully investigated in terms of electrical interactions, considering the operational and physical restrictions of these active cells, either in terms of normal steady state operation or for emergency conditions. These issues were fully addressed in this project with a large involvement from INESC Porto. The objectives set for this domain of research were the following:

- To define the possible operational architectures of MV multi-microgrids and corresponding requirements both under normal and emergency conditions;
- To analyse the interaction of the MGCC of each LV Microgrid with existing DMS tools in order to improve network operating conditions;
- To adapt and enhance existing DMS functionalities and tools, namely regarding coordinated voltage control and local state estimation in MV distribution networks, having in mind the introduction of an intermediate management control agent – the CAMC;
- To evaluate the possibility of having microgrids participating in frequency control in interconnected mode or during emergency conditions where islanding will be allowed;

- To investigate and develop effective control strategies and procedures to deal with emergency operation (involving islanding and black start, assuming a fault occurred upstream in the network);
- To investigate ways of having multi-microgrids and other DG participating in ancillary services (such as voltage support, service restoration and reserves) and short-term markets, involving the development of the specific tools for these purposes.

3.3 Multi-Microgrid Control and Management Architecture

The development of the microgrid concept has lead to the need for a detailed analysis of the interaction between the MGCC and the central DMS, which is in charge of the whole distribution network, in both normal and emergency operating modes. This has already been addressed in several publications available in the scientific literature [4], [30].

However, the new concept of multi-microgrids is related to a higher level structure, formed at the MV level, consisting of LV microgrids and DG units connected on adjacent MV feeders.

Nowadays, the DMS is wholly responsible for the supervision, control and management of the whole distribution system. In the future, in addition to this central DMS, there may be two additional management levels:

- The HV/MV substation level, where a new management agent – the CAMC – will be installed as illustrated in Figure 3-1. The CAMC will accommodate a set of local functionalities that are normally assigned to the DMS (as well as other new functionalities) and will be responsible for interfacing the DMS with lower level controllers.
- The microgrid level, where the MGCC, to be housed in MV/LV substations, will be responsible for managing the microgrid, including the control of the microsources and responsive loads. Voltage monitoring in each LV grid will be performed using the microgrid communication infrastructure.

Similarly to what happens in the microgrid concept, in multi-microgrid systems, two modes of operation and operating state may be envisaged. These two possible operating modes are:

- **Normal Operating Mode** – when the multi-microgrid system is operated interconnected to the main distribution grid.
- **Emergency Operating Mode** – when the multi-microgrid system is operated in an autonomous mode (islanded from the main power system) or, following a blackout, when the multi-microgrid system is contributing to service restoration by triggering a black start procedure.

The main issue when dealing with control strategies for multi-microgrid systems is the use of individual controllers, which should have a certain degree of autonomy and be able to communicate with each other in order to implement certain control actions. A partially decentralized scheme is justified by the tremendous increase in both dimension and complexity of the system so that the management of a multi-microgrid system requires the use of a more flexible control and management architecture.

Nevertheless, decision-making even with some degree of decentralized control should still adhere to a hierarchical structure. A central controller should collect data from multiple devices and be able to establish rules for low-rank individual controllers. These actions must be set by a high level central controller (*i.e.* the DMS), which ought to delegate some tasks in other lower level controllers (either the CAMC or the MGCC). This is due to the fact that a central management would not be effective because of the large amount of data to be processed, and therefore would not allow an autonomous management, namely during islanded mode of operation. The CAMC must then have the ability to communicate with other local controllers (such as MGCCs or with DG sources or loads connected to the MV network), serving as an interface for the main DMS.

Consequently, the CAMC plays a key role in a multi-microgrid system as it will be responsible for the data acquisition process, for enabling the dialogue with the DMS located upstream, for running specific network functionalities and for scheduling the different resources in the downstream network. A general picture of this new management and control architecture is shown in Figure 3-1.

In order to implement these functionalities, a communication infrastructure must be developed. A proposal for a communication scheme in multi-microgrid systems is presented in Figure 3-2.

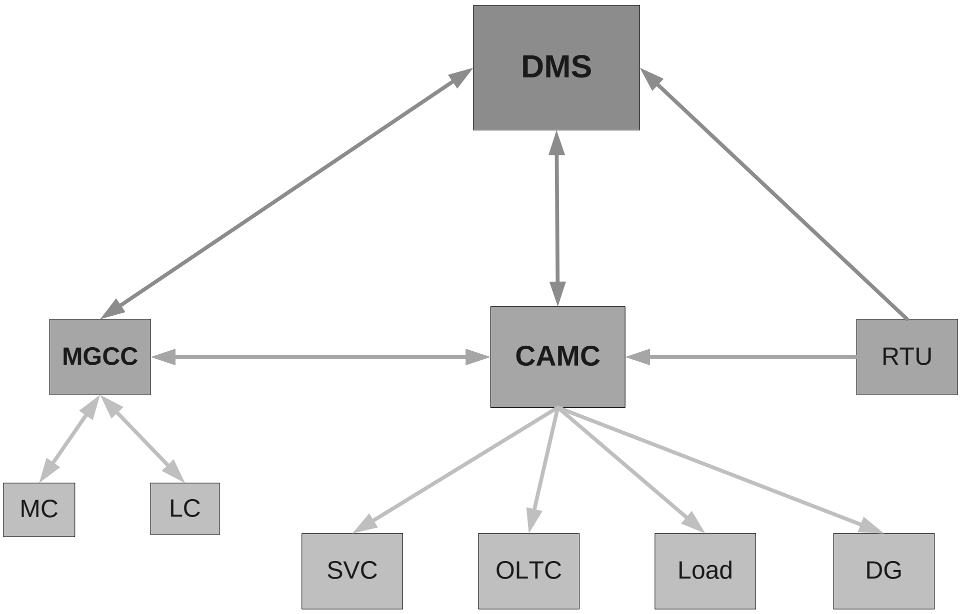

Figure 3-2 – Communication Scheme of a Multi-MicroGrid System

Regarding this proposed communication scheme, the importance of decentralized control in the system architecture is related to the fact that, especially in emergency mode of operation, the communication between the different controllers may be compromised. Therefore, it is crucial that multi-microgrid operation should not be jeopardized by a failure in communications. The communications between controllers may be bidirectional or unidirectional, depending on the type of controllers involved. Still, some form of hierarchical structure must be observed in communication flows.

3.4 Hierarchical Control Approach

In this context, a three-level hierarchical control structure must be adopted in order to profit from the advantages of hierarchical control, as depicted in Figure 3-3. These three main control levels are described next:

- **Control Level 1** – where the HV distribution network is managed by a DMS, in charge of the whole distribution grid.
- **Control Level 2** – where the MV network is managed by a CAMC, which is responsible for managing several microgrids together with DG units and controllable loads directly connected to MV feeders.
- **Control Level 3** – where the LV network is managed and controlled by an MGCC. Also several devices such as SVCs and OLTC transformers are included in this level, but are coordinated by the CAMC.

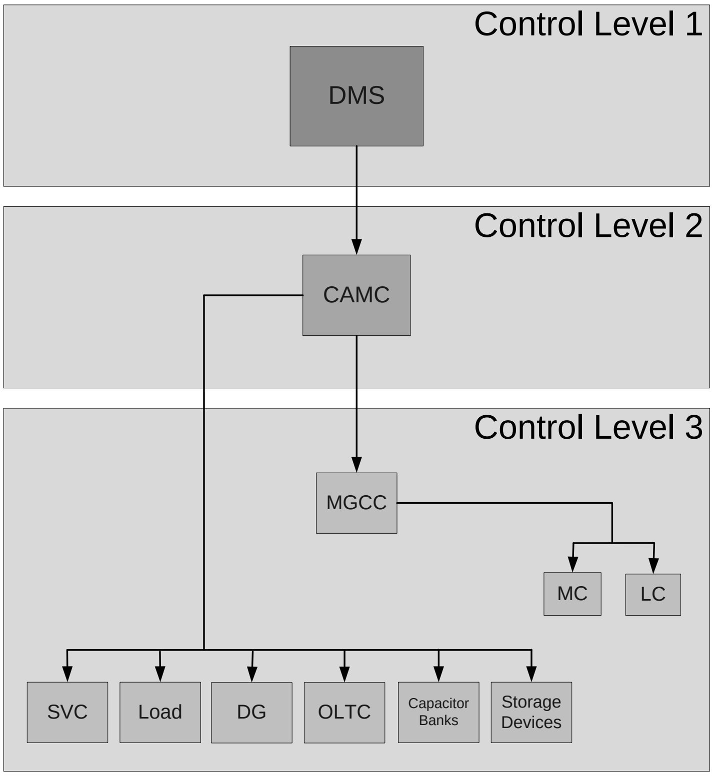

Figure 3-3 – Control Scheme of a Multi-MicroGrid System

As may be inferred from Figure 3-3, this hierarchical control architecture closely follows the physical structure of the distribution grid.

The various controllers may perform several tasks autonomously or work in a coordinated way with other controllers. Nevertheless, some redundancy must exist in order to overcome situations where specific control actions may be inhibited and there will be the need for a higher-rank controller to step into action.

As previously stated, the CAMC will work as an interface between the microgrids (via corresponding MGCCs) and the central DMS. Consequently, the most important interactions will occur between the three main controllers, *i.e.* the DMS, the CAMC and the MGCC. These interactions are addressed to in more detail in the next section.

3.4.1 Interactions among Controllers and Data Flows

Since the CAMC is the head of the multi-microgrid system, it will be responsible for managing all the devices located at Control Level 3 in order to ensure coordinated operation. The main devices under CAMC supervision are:

- MGCCs;
- SVCs;
- MV-connected loads;
- MV-connected DG units;
- OLTC transformers;
- Capacitor banks;
- Storage devices.

Each of these devices should be able to receive commands from the CAMC and periodically send information concerning its operating status and local network data back to the CAMC. This will enable the CAMC to define the operating conditions of the MV network and, consequently, the operating point for each of the devices.

As regards technical operation of the multi-microgrid, the main controls that can be implemented for the main controllers are:

- MGCCs – increase/decrease generation/consumption of active/reactive power;
- Loads – shed/reconnect;
- DG units – increase/decrease generation of active/reactive power;
- Storage devices – increase/decrease generation/consumption of active power;
- Reactive power support devices[24] – increase/decrease generation/consumption of reactive power.

In Figure 3-4, the information flow between the main devices in the multi-microgrid system is shown [78].

Furthermore, similarly to what happens for the CAMC, the MGCCs use the data from the devices in the LV network in order to determine set-points that will be sent back to them. These controls are:

- Microgenerators (through the corresponding MCs) – increase/decrease generation of active/reactive power;
- Loads (through the corresponding LCs) – shed/reconnect;
- Storage devices (through the corresponding MCs) – increase/decrease generation/consumption of active power.

[24] These include capacitor banks, SVCs, STATCOMs, *etc.*

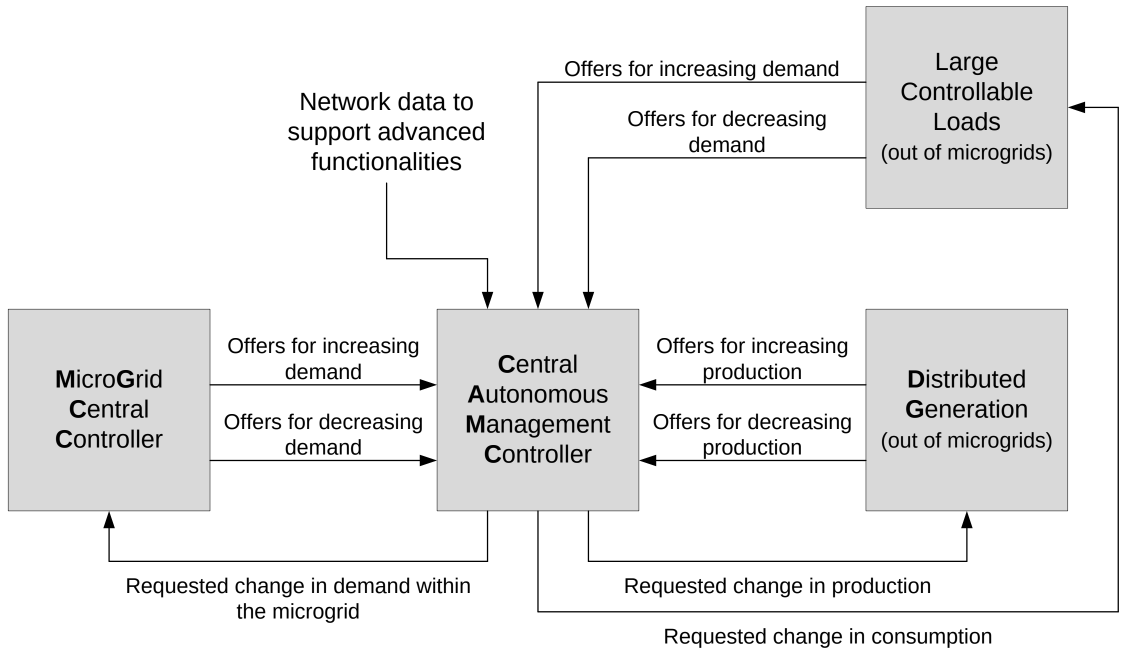

Figure 3-4 – Data Exchange between the CAMC, the MGCC, MV Loads and DG Units (adapted from [78])

At the microgrid level, the main interactions between the MGCC and local controllers are illustrated in Figure 3-5 [66].

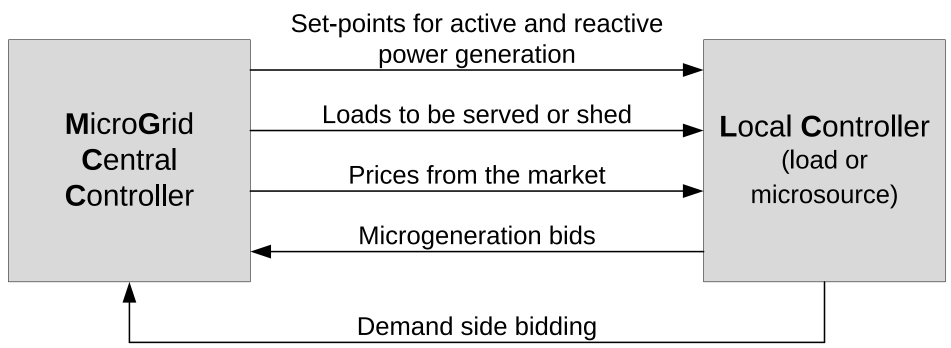

Figure 3-5 – Data Exchange between the MGCC and Local Controllers (adapted from [66])

3.4.2 Operating Modes

As seen previously, the proposed control architecture can be exploited in two distinct situations: when the MV network is interconnected to the main distribution system or when the MV network is islanded and operating autonomously.

According to the operation mode, the tasks assigned to the CAMC are distinct. For instance, in interconnected mode there is no need for an active participation in frequency control while in islanded mode this functionality is vital.

A state diagram for the multi-microgrid is presented in Figure 3-6.

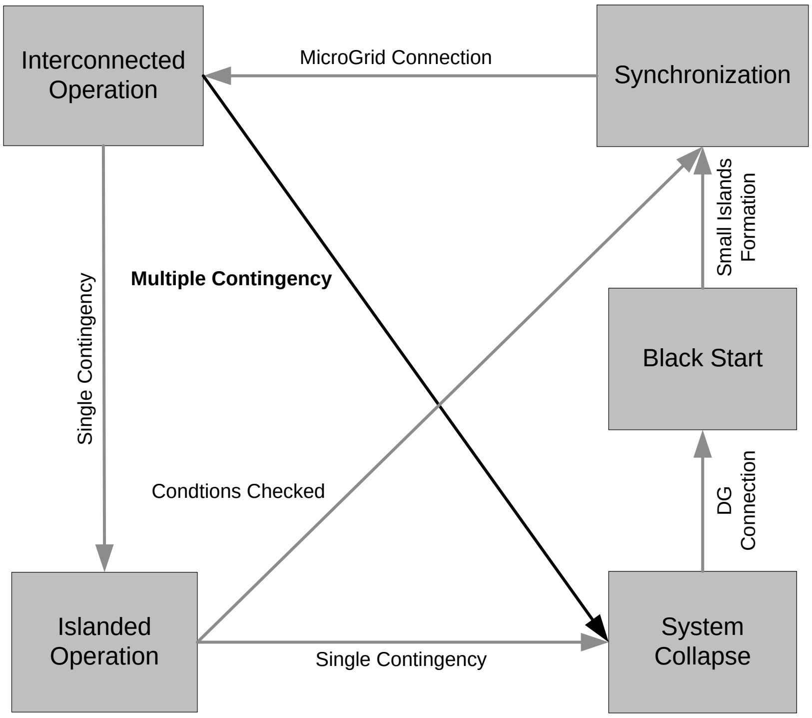

Figure 3-6 – Multi-Microgrid State Diagram

In this figure, five different states may be observed:

- **Interconnected operation** – where the multi-microgrid system is connected to the main distribution network, participating in frequency regulation, control scheduling (market operation), but also voltage/var control.
- **Islanded operation** – where the multi-microgrid operates autonomously controlling both voltage and frequency.
- **Synchronization** – where the microgrid is being synchronized with the main MV network (checking the conditions in terms of phase sequence, frequency and voltage) and after that the CAMC authorizes the reconnection process.
- **System collapse** – where a blackout occurred following a contingency or a series of contingencies.
- **Black start** – where the restoration procedure is initiated with the connection of DG sources followed by the formation of small islands.

The main characteristics of both these operation modes are described in the following sections.

3.4.2.1 Interconnected Operation Mode

In interconnected mode, the frequency control module of the CAMC should be disconnected. In this case, frequency control will be managed at a central level, by the DMS at the distribution level. The multi-microgrid system, controlled by the CAMC, will behave like a VPP, following requests from the DMS in order to change the balance between load and generation within the multi-microgrid. From the DMS point of view, the multi-microgrid may be regarded as a flexible load.

In terms of frequency support, the multi-microgrid may contribute to primary frequency control, although its contribution may be small, given the scale of the generation resources available.

An important contribution by the CAMC can be provided for voltage/var support, in interconnected mode. The CAMC is able to control the devices available in the multi-microgrid system, managing the power flows in the microgrids (through the corresponding MGCCs), as well as DG units at the MV level, exploiting their power electronic interfaces. Therefore, it will be able to optimize the multi-microgrid system in a global way, minimizing active power losses, managing power flows and improving voltage profiles.

3.4.2.2 Islanded Operation Mode

The CAMC plays a key part in emergency operation, when the multi-microgrid system is islanded from the main distribution grid. Following the islanding of the multi-microgrid, usually after the occurrence of a fault in the upstream network, the CAMC will assume the responsibility for coordinated frequency control. This task will be critical in order to ensure the survival of the multi-microgrid in autonomous mode.

In this case, it is assumed that the CAMC coordinates the DG units and all the MGCCs of the microgrids that are connected to the MV multi-microgrid. Also, controllable loads directly connected to the MV network can be managed by the CAMC. The ability of the microgrid to operate in islanded mode was already addressed in several works available in the available scientific literature [30], [79].

The CAMC is able to measure the frequency almost continuously in order to provide set-points based on the frequency deviation to the devices under its control, thus raising or lowering generation and consumption within the multi-microgrid. This type of secondary control in emergency operation is similar to the traditional Automatic Generation Control (AGC). Basically, the CAMC will operate according to a pre-defined time cycle, using the frequency error in order to calculate active power set-points for loads and DG units directly connected to the MV level, as well as for the MGCCs [80], [81].

3.5 Decentralized Control Approach

An alternative to the hierarchical control architecture proposed in the previous section is the use of MAS, first introduced in Chapter 2. In fact, MAS have been used for some time now in order to facilitate the control of individual microgrids [82], [83], [84], [85]. This approach may be of particular interest especially for microgrid market participation.

According to Dimeas *et al.* [82], the use of MAS technology can solve a number of specific operational problems, such as:

- Centralized control is more complex, since small DG units have different owners, and therefore several decisions should be taken locally;
- There is a lack of dedicated communication facilities;
- Given that microgrids are expected to operate in a liberalized market, controller decisions for each device concerning the market should have a certain degree of "intelligence".

In [83], the same authors propose some changes to their original framework. Here, the MAS approach was developed as a tool not only to provide intelligence for the needs of complex tasks, but also to facilitate the design of the algorithm. In this work, microgrid operation and namely its participation in the energy market is addressed. The main idea of the algorithm presented is that every device should be able to decide what is best for itself as an individual. Of course, MAS does not aim exclusively at market participation and may also be used for other functionalities. Therefore, the proposed MAS architecture is considered as a first step towards a more comprehensive control mechanism.

The authors also compare the benefits from this decentralized control approach to centralized control, where the MGCC decides about the set-points for each controller. According to them, the main difference between the two approaches lies in the amount of information that is processed in each case. Also, it is said that a decentralized approach only needs a simple local network and the information exchange is limited to the essential data only, while a more centralized approach requires a significant data flow toward a single central point. Finally, it is argued that adopting a decentralized approach allows every DER manufacturer or loads to embed an agent in the corresponding controller, which would provide "plug-and-play" capabilities, contrary to a centralized system where the installation of any new component would require changes in the software for the central controller. Although some of the issues raised may be arguable, MAS remains as a promising alternative to a more centralized approach.

Some of these concepts were implemented on a small laboratory microgrid and on real networks, following the work developed within the framework of the More MicroGrids project. In this project, MAS techniques were applied to a small isolated power system in the Greek island of Kythnos [36]. In this case, loads and DG units are controlled by intelligent agents that cooperate in order to solve a certain problem. Also, a MAS agent was implemented in the Mannheim-Wallstadt microgrid [36].

It is clear that some of these concepts may be adapted for the case of multi-microgrid systems. This approach is, however, out of the scope of the work presented in this thesis.

3.6 Central Autonomous Management Controller Functionalities

In this context, existing DMS functionalities need to be upgraded due to the operational and technical changes that result from the adoption of the multi-microgrid concept, especially the introduction of the CAMC, and corresponding hierarchical control architecture.

The management of the multi-microgrid (MV network included) will be performed through the CAMC. This new controller will also have to deal with technical and commercial constraints and contracts in order to manage the multi-microgrid both in HV grid-connected operating mode and in emergency operating mode, as previously seen. The set of functionalities to integrate the CAMC is shown in Figure 3-7.

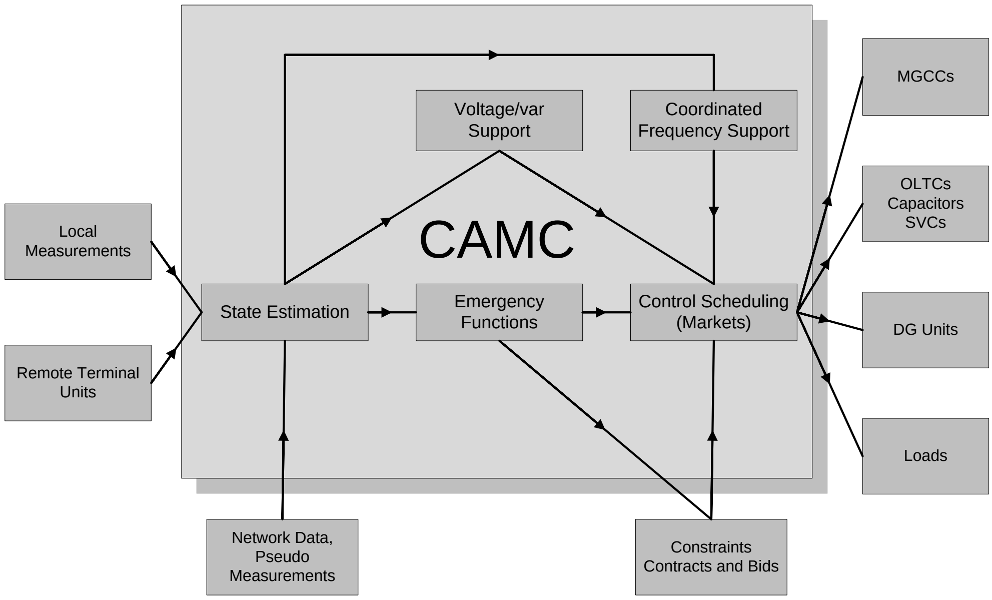

Figure 3-7 – CAMC Functionalities

It is important to stress that not all these functionalities may be available in any multi-microgrid system. Their availability will depend much on the type of network considered and on the characteristics of local DG units present as well as on the demand side resources available.

In multi-microgrid systems, microgrids together with DG units will have a significant impact on the electrical distribution system and will enable the participation of these units in providing ancillary services, such as coordinated voltage support.

The most relevant functionalities for the work presented in this thesis – voltage/var support and control scheduling (markets) –are summarily described in the next sections.

Also, in [86] and [87], all the main functionalities associated to the CAMC are detailed.

3.6.1 Voltage/var Support

Hierarchical control may be established for voltage control, similarly to what happens in frequency control as presented in [80].

A hierarchical voltage control scheme can be divided into three control levels, according to areas of action and deployment time [88]. These three levels are presented next:

- **Primary Voltage Control** – It keeps the voltage within specified limits of the reference values. AVRs are used to control voltage in primary control and their action takes effect in a few seconds.
- **Secondary Voltage Control** – It has the main goal of adjusting and maintaining voltage profiles within an area and of minimizing reactive power flows. Its action can take up to a few minutes. The control actions associated with secondary control include modifying reference values for AVRs, switching SVCs and adjusting OLTC transformers. A reference bus (also known as pilot bus) may be used to represent the voltage profile of a certain area in order to define the reference for secondary control.

- **Tertiary Voltage Control** – It has the goal of achieving an optimal voltage profile and coordinating the secondary control in accordance to both technical and economical criteria. It is usually based on an OPF algorithm. The time-frame of this control action is around some tens of minutes. The most common control variables used are generator voltage references, reference bus voltages and state of operation of reactive power compensators.

In Figure 3-8, a possible scheme for this hierarchical voltage control approach is presented.

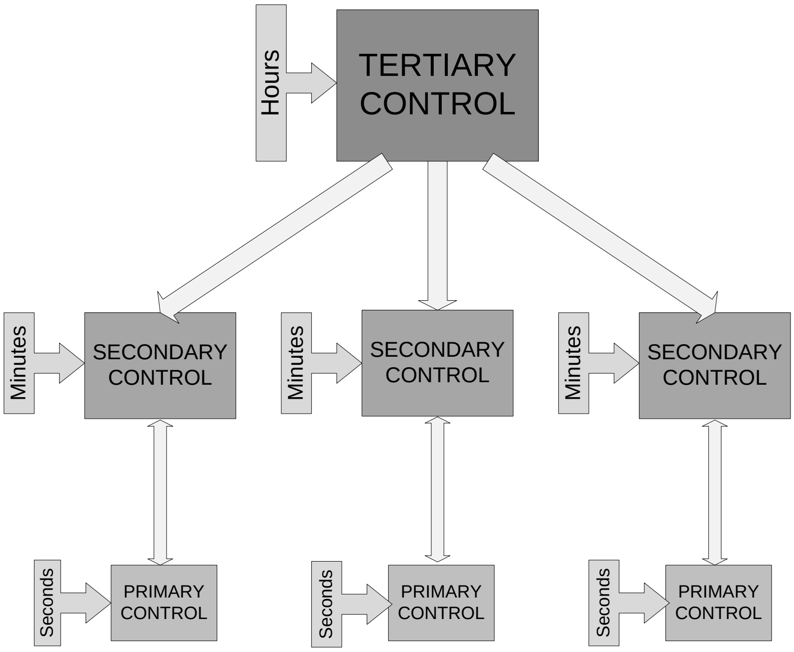

Figure 3-8 – Hierarchical Voltage Control

The CAMC will have a key role in this task since it will have the ability to control the power flows of the several microgrids (through the corresponding MGCCs) and optimize global system operation of multi-microgrid systems in order to minimize reactive power flows and improve voltage profiles.

Concerning multi-microgrid systems, secondary voltage control may be provided in either grid-connected or emergency modes of operation. However, tertiary voltage control can be considered as being provided only in grid-connected mode.

The main objective for solving the voltage/reactive power problem for a multi-microgrid system will be to optimize operating conditions by using control capabilities of power electronic interfaces from DG sources, OLTCs, SVCs and microgrids (which can be regarded as active cells).

Voltage control in multi-microgrids is a mixed optimization problem (*i.e.* it deals with both continuous and discrete variables), non-linear and with a strong hierarchical structure. This fact will imply dealing with voltage control sub-areas for each microgrid. Once a solution has been found to the global problem, the sub-solutions for individual microgrids will be tested in order to evaluate their feasibility, subject to the characteristics of their microgenerators. The optimization procedure will require a sequence of local sub-problem solutions and global problem solutions in order to converge to a near-optimum solution.

Voltage control in multi-microgrids is addressed in detail in Chapter 4.

3.6.2 Control Scheduling (Markets)

In order to promote incentives for the wide-spreading of microgrids and DG, a market structure to include the services provided by these units must be developed. With the development of this new market structure, major changes are going to take place, some of which have already been initiated. However, some service markets are at a relatively immature stage and a lot of adapting and upgrading will have to be done [65].

Open competitive markets for generation for both energy and ancillary services should be encouraged since they may improve efficiency and, hopefully, help in reducing electricity bills to the final customer. This structure, mainly concerning ancillary services provision, will surpass generation level by having load participation in several of these services. In particular, ancillary service markets are seen as a great opportunity for DG and microgrids, as seen previously in Chapter 2.

In this context, both electricity markets and ancillary service markets should be taken into account as drivers for promoting the deployment of multi-microgrid systems. The several microgrids would then be able to sell services according to global system needs, with rising prices in emergency conditions giving a clear sign of the desired response for the system. The microgrids or other DG not able to respond to system requirements might yet continue to operate in order to satisfy their own necessities, but those who could respond would receive an economic signal (*i.e.* benefit). This strategy implicates that both generators and consumers will see the electricity or service price according to the conditions of the system [89].

The main issue concerning market operation is related to the two operating modes for the multi-microgrid systems – islanded and grid-connected. One of the basic assumptions of an energy market is that power supplied from any generator can be delivered to any costumer. This would still be valid if the system were not split into several different islands, as may happen in emergency operation. This problem must be affectively tackled, especially since islanding will often result from unplanned events.

Also, the existence of bilateral contracts is a possibility for ensuring microgrid participation in ancillary services markets, namely in islanded operation. In this operating mode, full market operation will be difficult to implement given the urgency and variety of services that are required. Therefore, an independent market structure should be built for emergency operation and for normal operation. In order to ensure security of supply in emergency mode, a parallel scheme based on bilateral contracts for some key services could also be implemented.

3.6.2.1 Ancillary Services Markets

As previously seen, one of the most promising features of a multi-microgrid system is its potential ability to provide a variety of ancillary services. This can be achieved by profiting from the characteristics of the various microsources present, since DG is more suitable for providing some ancillary services than conventional central generators because many of these services can be more efficient if provided locally (*e.g.* voltage support) [90]. This capability will be fully developed once a market structure is designed to serve such a system. In this case, both loads and microgenerators may supply these services. Additionally, the use of storage devices with considerable capacity and fast response to load/generation imbalances will play an important role in multi-microgrid systems. These devices, combined with the use of power electronics, may help sustaining voltage sags and dips and enable the provision of ancillary services such as frequency regulation or voltage regulation.

Ancillary services to be provided within a multi-microgrid system may be divided in two different categories: ancillary services for normal operation and for emergency operation. The main ancillary services for multi-microgrids according to the operating mode are presented next.

- **Normal Operating Mode** –Frequency regulation and voltage/var control.
- **Emergency Operating Mode** – Frequency regulation, voltage/var control, reserves, black start and load following.

A brief description of the main ancillary services [69], [89] adapted for multi-microgrid systems according to the several kinds of their power sources is now presented after a quick review of some basic definitions.

Frequency regulation is the use of operating generators that are equipped with load-frequency control and that can change output quickly in order to follow load or generation fluctuations. Hence, regulation will help to maintain interconnection frequency, to minimize differences between actual and scheduled power flows between control areas, and to match generation to load within the control area.

Voltage/var control concerns the injection and absorption of reactive power in order to control voltage. In addition, supplying reactive power and real power locally will reduce losses on feeders and make the entire distribution circuit more efficient and less vulnerable to voltage collapse. Voltage control is generally accomplished by sending each generator a voltage set-point. In this case, the set-point signal would be sent by the CAMC to MGCCs which would then dispatch local microgrids through the corresponding MCs. Voltage/var control is seen as one of the most promising ancillary services to be provided by microgrids, given the local characteristic of voltage control.

Supply of reserves is required to maintain bulk power system reliability and may be open to competitive market participation. These services include spinning reserve and supplemental reserve and deal with restoring the balance between generation and load. The first requires an immediate response time (seconds) whereas the second requires only a response time of a few minutes. Backup supply may also be included for generation capacity available within a one hour time-frame.

Black start is the capability to start generation without outside power and restore a portion of the power system to service after a total system collapse. Black start is a service that microgrids and some other DG units appear to be qualified to provide since microgrids are expected to be inherently capable of operating independently of the power system. Microgrids may be able to participate in the black start procedure by aggregating and forming larger islands, which would then enhance the stability of the grid as it is being restored.

Load Following concerns the use of generation in order to meet the hour-to-hour and daily variations in system load, especially in emergency (islanded) operation.

Table 3-1 presents the availability of ancillary services provision by power source type technology available for microgrid operation [88], [91]. It can be observed that many microgeneration and DG technologies may provide at least some ancillary services to the power system.

Table 3-1 – DG Technological Capabilities for Ancillary Services Provision

Power Source Type	Frequency Regulation	Voltage Control	Reserves	Black Start	Load Following
CHP	YES*	YES	YES	YES	YES*
Diesel (SG)	YES	YES	YES	YES	YES
Wind Energy (IG directly connected)	NO	NO	NO	NO	NO
Wind Energy (DFIG)	YES**	YES	YES**	NO	NO
Wind Energy (SG + converter)	YES**	YES	YES**	NO	NO
PV	NO	YES	NO	NO	NO
Micro-Turbine	YES	YES	YES	YES	YES
Fuel Cell	YES***	YES	YES	YES***	YES***
Hydro Plant	YES	YES	YES	YES***	YES***

* Depending on the thermal industrial process

** Depending if deload solutions are adopted, such as proposed in [92]

*** Depending on the technology

3.7 Summary and Main Conclusions

The definition of an effective control scheme for multi-microgrid operation is a key issue in order to accommodate efficiently microgeneration and MV connected DG and to exploit their potential benefits. In particular, it is extremely important to specify the interactions among controllers, namely concerning the main new controller – the CAMC. Also, the interaction between the CAMC and the MGCC is crucial for ensuring efficient multi-microgrid operation.

The control strategy proposed is based on a hierarchical scheme, ensuring both autonomy and redundancy. A communication strategy for multi-microgrid systems is also important and must have the same characteristics of the control scheme due to the dimension and complexity of the system. An alternative approach to the hierarchical scheme proposed in this work may exploit the use of MAS.

Furthermore, the control strategy must take into account the two possible operating modes in a multi-microgrid system: a) grid-connected and b) islanded mode. State diagrams comprising these operating modes were derived above, exploring all possible operating scenarios and reviewing the main conditions for the transitions between states.

Finally, it was shown that the main CAMC functions should be adapted and/or duplicated from the traditional DMS modules. The functions identified here were: Coordinated Frequency Support, Voltage/var Support, State Estimation, Emergency Functions and Control Scheduling (Markets).

In particular, Voltage/var Support is a function with a strong hierarchical structure that comprises the formulation of a mixed, non-linear optimization problem. This functionality aims at optimizing operating conditions by using control capabilities of power electronic interfaces from DG sources, OLTCs, SVCs and microgrids (that can be regarded as active cells) and is described in detail in Chapter 4.

Concerning Control Scheduling (Markets) is also seen as a great opportunity for both MV connected DG and microgrids. In particular, participation in ancillary services provision is expected to be one of the most interesting prospects for multi-microgrid systems. The ancillary services to be provided by these systems were presented, taking into consideration the operating mode of the system. An approach to the development of ancillary services markets for voltage support is presented in Chapter 5.

"«*Would you tell me, please, which way I ought to go from here?*»
«That depends a good deal on where you want to get to,» said the Cat.
«I don't much care where—» said Alice.
«Then it doesn't matter which way you go,» said the Cat.
«—so long as I get SOMEWHERE,» Alice added as an explanation.
«Oh, you're sure to do that,» said the Cat, «if you only walk long enough.»"

Alice talking to the Cat in "*Alice's Adventures in Wonderland*" by Lewis Carroll (b. 1832 – d. 1898)

Chapter 4 – Coordinated Voltage Support

In this chapter, a novel strategy for voltage control in multi-microgrid systems is presented. This approach involves a coordinated action between the MV and LV levels of the distribution system, by managing all resources available such as microgrids, DG units directly connected at the MV level and OLTC transformers, as well as other reactive power support devices (capacitor banks or SVCs, for instance). In this case, voltage/var control is formulated as a mixed, non-linear optimization problem, which is solved using a meta-heuristic approach. The resulting algorithm is intended to integrate a tool designed for aiding the DSO in network operation. Given the dimension of the system to be managed, Artificial Neural Networks (ANNs) are employed to replace the full representation of active LV networks (*i.e.* microgrids) in order to enable the use of the tool in a real-time management environment.

4.1 Introduction

The algorithm presented in this chapter was developed aiming at the integration in a voltage control module to support network operation, which is one of the tasks of the DSO. Even though the program was built *ab initio* addressing issues such as computational speed and overall algorithm performance, it should be noted that, in order to develop a tool that can be effectively used in real-time operation, substantial additional effort still has to be made in order to optimize the computer code. However, the development of a properly optimized final code for the proposed voltage/var control algorithm is considered outside the scope of this work.

It should be noted that some parts of the work presented in this chapter, including initial developments of the approach, have already been published in journals [86], [93], conferences [94], [95] and book chapters [96]. Additionally, one report for the More MicroGrids project has also been developed [97].

As previously seen in Chapter 2, extreme operating conditions may occur due to the voltage rise effect, which is the result of the large-scale integration of DG (at the MV level) and/or microgeneration (at the LV level). It was also seen that several control strategies may be employed at the distribution level (particularly at the HV and MV levels) in order to ensure that voltage is maintained inside an admissible band. These strategies exploit the capability of DG to provide voltage support through reactive power injection together with capacitor banks and SVCs. In addition, the possibility of setting transformer taps and especially the use of OLTC transformers can also be exploited in a coordinated way with local resources.

Nevertheless, distribution systems have specific characteristics that may negatively affect traditional voltage control schemes. For instance, the decoupling between active power and voltage magnitude that can be observed at the transmission level does not hold at the lower voltage levels of the distribution level. Particularly at the LV level, reactive power control is not sufficient to maintain efficient system operation, especially since in LV networks the X/R ratio is low. This is explained in detail in Section 4.2.2. Therefore, in order to cope with high microgeneration penetration, an effective voltage control scheme must be based both on active and reactive power control.

In the future, a wide range of generation units are expected to be connected at the various voltage levels of the distribution system, in addition to the existence of responsive loads and dispersed storage solutions. In order to allow a large-scale deployment of these devices, namely DG units, the implementation of some type of hierarchical coordinated management scheme is required. This approach will enable taking full profit from the benefits that all these resources can bring to system operation. As already seen, although local control approaches may also be employed, a pure decentralized control approach will not be able to achieve an optimum and global solution.

Furthermore, the introduction of active cells such as microgrids can be seen as an additional resource, which is worth exploring given the control possibilities inherent to the microgrid concept. As seen in Chapter 3, in multi-microgrid systems, the CAMC is responsible for managing the MV and LV distribution system. In order to guarantee efficient control of the multi-microgrid system, the CAMC needs to manage all resources available, including DG units and loads directly connected to the MV network, microgrids, OLTC transformers, storage devices and devices for reactive power support (capacitor banks, *etc.*).

Consequently, in this thesis, a novel voltage control procedure is proposed that includes optimizing operating conditions by taking full use of DG, microgrid and OLTC transformer control capabilities. In multi-microgrid systems, it is necessary to address the problem of voltage control at both the MV and the LV levels. In order to ensure coordinated operation, a global voltage control algorithm will run at the MV level and the solution obtained will be tested at the LV level in order to evaluate its feasibility.

The proposed control functionality is intended to aid the DSO in real-time in optimizing distribution system operation in terms of voltage control based on data from generation scheduling and forecasting for loads and renewable sources for the next operation period, thus ensuring the possibility of use in real-time operation. The definition of this operation period may be open for discussion; however, in this work, a period of one-hour period was considered.

4.2 Mathematical Formulation

A hierarchical coordinated approach for voltage/var control in distribution systems with high penetration of DG can be formulated as an optimization problem.

Optimization techniques are used to find a set of design parameters, $x = \{x_1, x_2, \dots, x_n\}$, that can be defined as optimal in some way. In a simple case this might be the minimization (or maximization) of some system characteristic that is dependent on x.

In a more advanced formulation, the objective function, $f(x)$ to be minimized (or maximized) might be subject to a set of constraints.

A general description for the type of optimization problem that needs to be tackled is shown below [98].

$$min\ f(u,x) \tag{4-1}$$

$$subject\ to$$

$$G_i(u,x) = 0,\ i = 1 \dots m_e \tag{4-2}$$

$$G_i(u,x) \leq 0,\ i = m_e + 1 \dots m \tag{4-3}$$

Where

u	is the vector of control variables
x	is the vector of state variables
$f(u,x)$	is the objective function
$G(u,x)$	is the vector function that returns a vector of length m containing the values of the equality and inequality constraints

Equation (4-1) is the objective function of the optimization problem for the problem under study, which may aim at achieving several different goals such as:

- Minimize voltage deviation;
- Minimize the number of switching operations;
- Minimize active power losses.

Usually, in order to achieve these objectives, it is necessary to manage a set of control variables and monitor some observation variables.

Some of these goals can be included in the formulation of the objective function or be included as constraints to the optimization problem. For instance, the need for reducing the number of switching operations defined for an OLTC transformer may be achieved by minimizing the total number of tap changes during a certain time-frame (*e.g.* a 24-hour period) or by limiting the number of tap changes in two consecutive periods (*e.g.* 1-hour). The former approach implies adding a term to the objective function while the latter implies adding an additional constraint.

As may be inferred, some of these objectives are conflicting objectives, so that we are in fact dealing with a multi-objective problem, which can be formulated as presented in (4-4).

$$min\ [f_1(u,x), f_2(u,x) \dots f_n(u,x)]^T \tag{4-4}$$

Where

$f_i(u,x)$ is the i^{th} objective function

The solution to this multi-objective problem is a set of Pareto points[25]. Thus, instead of a unique solution to the problem (which is typically the case in traditional mathematical programming), the solution to a multi-objective problem is a (possibly infinite) set of Pareto points.

The equality constraints in (4-2) represent the power flow equations written in a general form that should be understood as a full AC power flow model.

The inequality constraints shown in (4-3) represent technical and operational limits, such as bands of admissible voltage values at nodes, active and reactive power from generation units, *etc.*

In conclusion, the voltage/var control algorithm proposed in this thesis is formulated as a mixed, non-linear multi-objective minimization problem.

4.2.1 Medium Voltage Network Control

As previously seen in Chapter 2, the means traditionally used for voltage control in distribution systems may exploit three main resources:

- OLTC transformers tap control;
- Reactive power compensation devices such as capacitor banks or SVCs;
- Reactive power management from DG units.

Traditionally, OLTC control, together with switching capacitor banks, is used for voltage control in distribution systems. Devices used for voltage and reactive power control in distribution systems are mostly operated based on the assumption that the voltage decreases along the feeder. Nevertheless, the connection of DG units fundamentally alters the feeder voltage profiles, which will obviously affect the voltage control in distribution systems. A range of options have traditionally been used to mitigate adverse impacts, such as reducing OLTC set-point voltage, changing the capacitor control or limiting the DG size according to the worst case operating scenarios [99].

The possibility of DG participation in voltage support by regulating reactive power must also be regarded as a valuable contribution to distribution system operation in addition to the use of other reactive power compensation devices.

In an uncoordinated approach, all the equipments are adjusted locally while in a coordinated approach all the available resources are exploited in order to obtain an optimum voltage profile and reactive power flow by remotely adjusting each device.

[25] Pareto solutions are those for which improvement in one objective can only occur at the cost of worsening of at least one other objective.

Given the needs of the control system designed to support network operation, one problem that is commonly associated to the control of the several devices is their deterioration due to intensive use. It is known that frequent changes in tap position of OLTC transformers or capacitor banks may damage or significantly reduce the lifetime of these devices [52], [100], [101]. Therefore, a control strategy that limits frequent switching operations in this type of devices should be favoured. Furthermore, by involving DG in voltage control besides reducing voltage fluctuations in the distribution system may also aid in reducing the number of OLTC operations [99].

There are two distinct ways of controlling tap changes in transformers. The first one, which is the approach followed in this work, is sending set-points to change the tap position of the transformer according to certain operational requirement. A second approach would be to consider the possibility of automatic tap change, *i.e.* automatically adjusting the tap value in order to ensure a specific voltage value at the terminal of the transformer following load changes.

4.2.2 Low Voltage Network Operation

Voltage control in LV networks is usually achieved by local compensation or by adjusting OLTC tap settings. Nevertheless, in particular with the advent of microgeneration, new methodologies should be developed in order to tackle effectively the voltage control problem at the lower voltage levels in the distribution system.

As previously discussed, the characteristics of LV networks have a great influence on the voltage control strategy to be implemented. Since LV lines tend to be highly resistive, traditional voltage control based only on reactive power management is ineffective.

In order to understand the influence of LV networks' characteristics, consider the example system presented in Figure 4-1.

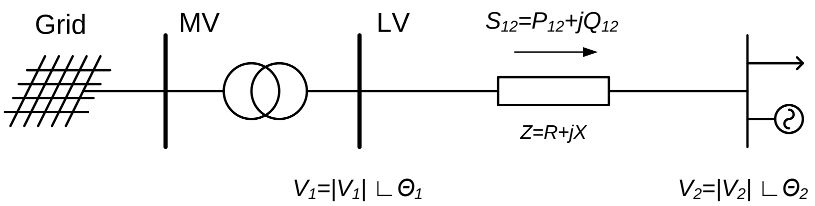

Figure 4-1 – Example System

The expressions that determine the power flow in the LV line represented in Figure 4-1 (neglecting shunt admittances) are:

$$P_{12} = \frac{R \cdot V_1^2 - R \cdot V_1 \cdot V_2 \cdot \cos\theta_{12} + X \cdot V_1 \cdot V_2 \cdot \sin\theta_{12}}{R^2 + X^2} \quad \textbf{(4-5)}$$

$$Q_{12} = \frac{X \cdot V_1^2 - X \cdot V_1 \cdot V_2 \cdot \cos\theta_{12} - R \cdot V_1 \cdot V_2 \cdot \sin\theta_{12}}{R^2 + X^2} \quad \textbf{(4-6)}$$

With

$$\theta_{12} = \theta_1 - \theta_2 \tag{4-7}$$

Where

V_i is the voltage magnitude at bus i
θ_i is the voltage angle at bus i
S_{ij} is the apparent power flow in the branch connecting bus i to bus j
P_{ij} is the active power flow in the branch connecting bus i to bus j
Q_{ij} is the reactive power flow in the branch connecting bus i to bus j
Z is the impedance of the branch connecting bus 1 to bus 2
R is the resistance of the branch connecting bus 1 to bus 2
X is the reactance of the branch connecting bus 1 to bus 2

Considering that, in LV networks, the line resistance is usually much greater than the line reactance (*i.e.* $R \gg X$), the following expressions can be derived from (4-5) and (4-6):

$$P_{12} = \frac{V_1^2 - V_1 \cdot V_2 \cdot \cos\theta_{12}}{R} \tag{4-8}$$

$$Q_{12} = \frac{V_1 \cdot V_2 \cdot \sin\theta_{12}}{R} \tag{4-9}$$

According to (4-8), it may be seen that, in order to be able to inject active power from bus 2 to bus 1 in a resistive network, voltage should be higher at the bus 2 than at bus 1 (*i.e.* $V_2 > V_1$). This shows that, contrary to what happens in the transmission system or even at some voltage levels of the distribution system, controlling reactive power flow is not effective for voltage control in LV networks. In this case, overvoltages may occur and generation shedding may become the only effective means for controlling voltage.

On the other hand, it is expected that LV networks will in the future accommodate generation, *i.e.* they will become "active" networks comprising not only loads but also microgeneration units. One of the main characteristics of these networks is related to the fact that both loads and microgeneration units are usually single-phase given their small power rating. This means that LV networks may suffer from phase unbalance, contrary to what happens at the MV or HV levels of the distribution system, for instance.

Furthermore, with the presently available incentives for connecting renewable-based microgeneration devices such as small PV panels next to the LV consumers, these will become increasingly common, so that the voltage rise effect can be particularly severe considering that these sources may generate power out of peak load periods. Consider the following example: in an LV network with mainly residential consumers that have a fair amount of PV-based microgeneration attached, it is likely that PV panels will be generating at their maximum output power in the period around 13h. However, this will not coincide with the peak load period for residential consumers, which is expected to be at around 21h. This means that there will be an excess of generation that must be "forced" upstream into the MV distribution network, at the expense of high voltage profiles at the customers located near the PV generators. In these extreme situations, there may be the need for curtailing some of this generation that cannot be accepted by the distribution system without causing operational problems.

Considering the growing control potential now available, LV networks ought to exploit the control capabilities of microsources through their power electronic interfaces. This will enable controlling the active power of microsources (as well as their reactive power, depending on the type of requirements that are set for microgeneration) in order to achieve a good performance of the voltage control algorithm.

4.2.3 Control Variables

The voltage-var control scheme presented here exploits the control capabilities available for distribution system operation. Here, the main control variables considered are:

- Reactive power from MV-connected DG sources;
- Capacitor banks steps;
- OLTC transformer tap settings;
- Microgeneration shedding.

These control variables are regarded as set-points that are sent to each device (either a DG unit, a microgrid or an OLTC transformer) exploiting the communication infrastructure available in multi-microgrid systems through the hierarchical control approach described in Chapter 3.

Accordingly, set-points for reactive power generation/consumption are sent to DG units directly connected to the MV level, following requests from the CAMC. Set-points are also sent in order to adjust tap settings in OLTC transformers and capacitor banks, which are also under CAMC control. Finally, considering microgeneration shedding inside a microgrid, a set-point is sent to the corresponding MGCC indicating that microgeneration should be reduced according to that set-point. This information is then sent by the MGCC to individual MCs (according to the control scheme also presented in Chapter 3) that receive an individual set-point in order to lower the generation of the associated microsource or microsources.

It can be seen that some control variables such as active and reactive power from generators can be modelled as continuous variables while other, which include OLTC tap settings and capacitor bank steps, are of a discrete nature, as shown in [50].

4.2.4 Objective Function

The definition of the objective function to be used by the algorithm should be the main concern when formulating an optimization problem. In this case, a multi-objective framework to address the voltage/var control problem was envisioned, using the following two objective functions:

$$min \sum P_{loss} \tag{4-10}$$

$$min \sum \mu G_{shed} \tag{4-11}$$

Where

P_{loss} are the active power losses in the network
μG_{shed} is the amount of microgeneration shed

And considering that $P_{loss} = f(V, \theta)$, with V and θ being the voltage magnitude and voltage angle, respectively, *i.e.* the state variables of the problem defined next.

One possible approach to address this multi-objective problem is to incorporate the objective functions using a type of trade-off approach, as shown in (4-12).

$$min \left(\alpha \cdot \sum P_{loss} + (1-\alpha) \cdot \sum \mu G_{shed}\right) \tag{4-12}$$

Where

α is the decision parameter

The parameter α presented defines the relation between a variation in the amount of microgeneration shedding and a variation in the active power losses. This decision parameter should reflect the preferences of the decision-maker, which in this case should be the DSO. This means that the decision-maker must decide which objective should be favoured (active power losses or microgeneration shedding) by defining the appropriate value for α.

The possibility of adding an additional term to the objective function was also analysed during the development stages of the algorithm, according to what was discussed in Section 4.2. This third term would correspond to the minimization of OLTC transformer tap changes in consecutive periods. Some tests were performed using this new formulation including the three terms in the objective function (loss minimization, microgeneration shedding minimization and OLTC transformer switching actions minimization). However, this formulation was abandoned since it seemed to affect the convergence of the algorithm. Instead, the solution sought was to include an additional constraint to the problem that reflected the need for minimizing the number of tap changes in OLTC transformers in consecutive runs of the algorithm. This solution is not only easier to implement but also shows faster convergence in some situations. The modelling adopted for this constraint is further described in Section 4.2.5.2.

4.2.5 Constraints

The constraints used here can be separated into two distinct groups:

- Equality constraints;
- Inequality constraints.

The first group includes the traditional power flow equations, considering a full AC model, and the second group is mainly related to operation limits, such as admissible bands for voltage.

4.2.5.1 Equality Constraints

The equality constraints that must be verified correspond to the power flow equations considering a full AC power flow model, as presented below.

$$P_i^G - P_i^L = \sum_{k=1}^{N} V_i \cdot V_k \cdot (G_{ik} \cdot \cos\theta_{ik} + B_{ik} \cdot \sin\theta_{ik}) \quad \textbf{(4-13)}$$

$$Q_i^G - Q_i^L = \sum_{k=1}^{N} V_i \cdot V_k \cdot (G_{ik} \cdot \sin\theta_{ik} - B_{ik} \cdot \cos\theta_{ik}) \quad \textbf{(4-14)}$$

Where

P_i^G, P_i^L	is the active power generation from DG and microgeneration and the active power consumption at bus i, respectively
V_i	is the voltage at bus i
G_{ik}	is the real part of the element in the Admittance Matrix (Y_{bus}) corresponding to the i^{th} row and k^{th} column
B_{ik}	is the imaginary part of the element in the Y_{bus} corresponding to the i^{th} row and k^{th} column
θ_{ik}	is the difference in voltage angle between the i^{th} and k^{th} buses
Q_i^G, Q_i^L	is the reactive power generation/consumption at bus i

4.2.5.2 Inequality Constraints

Inequality constraints are usually associated to physical limits of devices. The main inequality constraints considered in the formulation of this optimization algorithm for voltage/var control are presented below.

$$S_{ik} \leq S_{ik}^{max} \quad \textbf{(4-15)}$$

$$V_i^{min} \leq V_i \leq V_i^{max} \quad \textbf{(4-16)}$$

$$Q_i^{min} \leq Q_i^G \leq Q_i^{max} \quad \textbf{(4-17)}$$

$$t_i^{min} \leq t_i \leq t_i^{max} \quad \textbf{(4-18)}$$

Where

S_{ik}	is the apparent power flow in branch ik
S_{ik}^{max}	is the maximum apparent power flows in branch ik
V_i	is the voltage at bus i
V_i^{min}, V_i^{max}	are the minimum and maximum voltage at bus i
Q_i^G	is the reactive power generation at bus i

Q_i^{min}, Q_i^{max}	are the minimum and maximum reactive power generation at bus i
t_i	is the transformer tap of or capacitor step position of OLTC transformer or capacitor bank i
t_i^{min}, t_i^{max}	are the minimum and maximum tap of OLTC transformer or capacitor bank i

In this work, the approach chosen to limit the number of switching actions was to include an additional constraint. This constraint was included in order to prevent OLTC transformer taps from deteriorating due to intensive use, according to what was described in Section 4.2.1. It was implemented by restricting the number of tap position changes in two consecutive 1-hour periods (or runs of the algorithm), according to (4-19). The number of maximum tap changes allowed can be adjusted to reflect the policy of the decision-maker, *i.e.* the DSO.

$$\left|t_i^k - t_i^{k-1}\right| \leq N_i^{max} \cdot \delta_i \qquad \textbf{(4-19)}$$

Where

t_i^k	is the tap setting for OLTC transformer i at period k
t_i^{k-1}	is the tap setting for OLTC transformer i at period $k-1$
N_i^{max}	is the number of maximum allowable switching operations for OLTC transformer i
δ_i	is the step size changes allowed for OLTC transformer i

It should be noted that, in this work, the step size δ_i is assumed uniform, without loss of generality.

4.3 Development of the Approach

As previously seen, an approach for voltage/var control in distribution networks integrating DG and microgrids can be built by formulating an optimization problem. The main characteristics of this formulation are presented in the following section, with emphasis on the optimization method and on the implementation of the voltage/var control algorithm as a tool to be made available for assisting network operation.

4.3.1 Optimization Algorithm

Previous knowledge on the problem to be solved can be extremely useful in order to conveniently choose an optimization method. Hence, the characteristics of the problem should be carefully considered when selecting the more suitable approach.

Non-linear optimization techniques, of the variety known as stochastic search algorithms or meta-heuristics aim at finding the global optimum or, at least, a good local optimum without requiring many previous assumptions on the problem. This approach competes with classical methods when it comes down to selecting an optimization algorithm. Evidently, both approaches have their advantages and drawbacks. Usually, classical methods are well-known and reliable for solving either simple problems or more complex problems where some prior knowledge on the problem is available, and if carefully implemented are able to ensure convergence to a local optimum (provided, of course, there is one). On the other hand, meta-heuristics are generally well suited for problems where no prior structural information is available and which involve more complex modelling issues. However, they usually do not guarantee convergence, except perhaps in stochastic or probabilistic terms.

The optimization problem as presented in this chapter may be formulated as a mixed, non-linear optimization problem. This means that both continuous and discrete variables are considered. Many classical methods for optimization are not suitable for dealing with discrete and continuous variables simultaneously because of the "combinatorial explosion" of the values of discrete variables. Thus, they must rely either on previous knowledge of the problem at hand. On the other hand, meta-heuristics are intrinsically able to handle both continuous and discrete variables.

Although the choice of an optimization method may always be debatable, for this particular problem, a meta-heuristic approach was preferred knowing that in computer science as in life "there are no free lunches"[102].

Several examples of the application of meta-heuristics to the voltage/var problem can be found in the available scientific literature [50], [51], [103], [104], [105], [106] and [107]. The meta-heuristic approach chosen was EPSO, which is presented in detail in the next section.

4.3.1.1 Evolutionary Particle Swarm Optimization

EPSO is a hybrid method based on two already well-established meta-heuristic optimization techniques: Evolutionary Strategies (ES) and Particle Swarm Optimization (PSO). This method was developed in INESC Porto for a project with funding from the Portuguese Foundation for Science and Technology[26].

ES were developed by Rechenberg, Schwefel and Bienert [108] and are algorithms that imitate the principles of natural evolution as a method to solve parameter optimization problems. As all evolutionary algorithms, they use the collective learning process of a population of searching individuals for which each individual represents a point in the space of potential solutions. These methods rely on the definition of a fitness function, *i.e.* a specific function that is able to provide a measure of the quality of each individual (or solution), thus enabling the definition of a ranking of solutions. Consequently, the fitness function is the key element in every evolutionary algorithm.

PSO was developed by Kennedy and Eberhardt [109] and was introduced as a method for optimizing non-linear functions. This method aims at modelling social behaviour and has roots in two main component methodologies. On one hand, it is tied to biologically-derived algorithms, inspired particularly from bird flocking, fish schooling and swarming theory. On the other hand, it is also related to evolutionary algorithms. This method was discovered through simulation of a simplified social model based on the original idea of simulating the choreography of bird flocks. Furthermore, swarm behaviour suggested that individual members of the swarm can profit from discoveries and experience of other swarm members, *i.e.* social sharing of information can provide a decisive evolutionary advantage. Similarly to ES, PSO is initialized with a population of random solutions. Then, each solution is assigned a

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[26] *Fundação para a Ciência e a Tecnologia* (FCT) project POSC/EEA-ESE/60980/2004.
For more information see http://epso.inescporto.pt/

randomized velocity and all the potential solutions (called particles) are scattered throughout the problem space.

As a result, EPSO brings together the best-of-two-worlds: it is a PSO algorithm because there is exchange of information among solutions and an ES because solutions are mutated and passed on to the following generations.

Applications of EPSO to problems in the power systems can be found in the available scientific literature [110], [111], [112], [113] where the superiority of EPSO is claimed when comparing to other meta-heuristics, in terms of both convergence speed and best solution achieved.

The variables or parameters in EPSO are divided into object parameters (the X variables – control parameters of the problem) and strategic parameters (the weights w). The algorithm considers a set of solutions or alternatives that are called particles. The X variables include all the control variables used in the voltage and reactive power control optimization problem, as described in the previous section. Strategic parameters w are used to control the behaviour of the optimization algorithm.

In EPSO, each particle (or solution at a given stage) is defined by its position X_i^k and velocity V_i^k for the coordinate position i and particle k.

Considering a population with a set of particles, the general scheme of EPSO is presented next:

- **Replication** – each particle is replicated r times.
- **Mutation** – each particle has its weights w mutated.
- **Reproduction** – each particle generates offspring according to the particle movement rule.
- **Evaluation** – each offspring has its fitness evaluated.
- **Selection** – the best particles are selected by stochastic tournament[27].

The particle movement rule for is explained in detail below.

Given a particle X_i, a new particle X_i^{new} can be obtained from:

$$X_i^{new} = X_i \cdot V_i^{new} \tag{4-20}$$

With

$$V_i^{new} = w_{i1}^* \cdot V_i + w_{i2}^* \cdot (b_i - X_i) + w_{i3}^* \cdot \left(b_g^* - X_i\right) \tag{4-21}$$

Where

X_i is the position of the particle
V_i is the velocity of the particle
w_{ik}^* are the strategic parameters (weights)

[27] A selection mechanism which randomly chooses two individuals from the population and selects the one with best fitness with a probability (1−ζ), where ζ is a parameter belonging to the interval [0, 1].

b_i is the best solution of each particle
b_g^* is the best solution among all particles

The weights w_{ik}^* are mutated as follows (the symbol * indicates that the corresponding parameters were subject to a mutation process):

$$w_{ik}^* = w_{ik} + \tau \cdot N(0,1) \qquad \textbf{(4-22)}$$

Where

τ is a fixed learning parameter
$N(0,1)$ is the random variable with standard Gaussian distribution (mean = 0; variance = 1)

Each particle generates an offspring determined by a PSO movement rule as defined by equations (4-20) and (4-21). On one hand this can be seen as an elitist process since the particle best ancestor and the swarm global best are kept from generation to generation. On the other hand, the recombination operator is adaptive and evolves over the generations through the mutation of the particle strategy parameters according to (4-22).

The global best b_g^* is also mutated as shown below:

$$b_g^* = b_g + w_{i4}^* \cdot N(0,1) \qquad \textbf{(4-23)}$$

In this case, w_{i4}^* defines the "size" of the neighbourhood of b_g where it is considered more likely to find the "real" global best solution (assuming it exists).

Figure 4-2 illustrates how the position of a particle is determined in an EPSO algorithm.

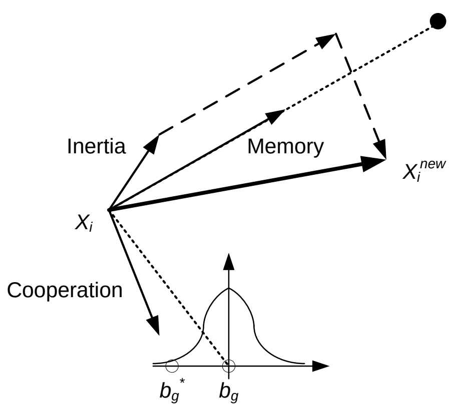

Figure 4-2 – Movement of a Particle in EPSO

Again, it should be pointed out that the vector associated with the cooperation factor does not point exactly to the global optimum b_g but to a "mutated" location, as defined in (4-23).

The scheme of a general particle k in EPSO is shown below.

X_1^k	X_2^k	…	X_n^k	w_{1k}^*	w_{2k}^*	w_{3k}^*	w_{4k}^*

Using EPSO, it is possible to consider discrete variables, which can included in the optimization problem as continuous variables rounded to the nearest discrete feasible value.

Concerning constraints, these are usually dealt with in the traditional evolutionary strategies way, *i.e.* by adding penalties to the fitness function. Several penalty functions can be used such as linear penalty functions, quadratic penalty functions or exponential penalty functions, as shown in Figure 4-3. Quadratic and exponential penalty functions are often used since they tend to penalize larger deviations more.

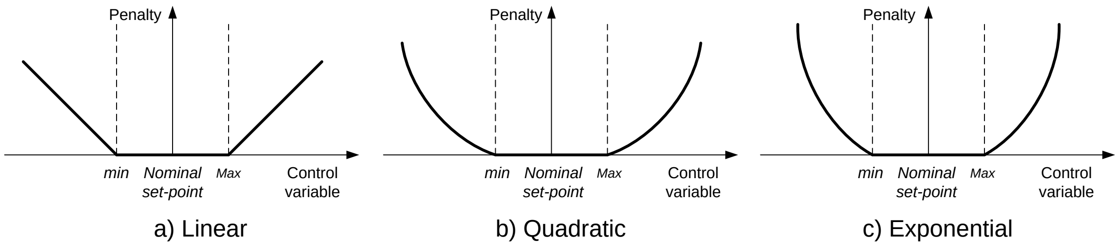

Figure 4-3 – Common Penalty Functions for EPSO

A general overview of the EPSO algorithm used in this work is presented in Figure 4-4, comprising the main steps involved.

Additional details on the EPSO algorithm can be found in [114] and [115].

4.3.2 Coordination and Decoupling

Voltage/var control is traditionally one of the most important and desirable functions of a modern DMS. This function deals with the complexity of voltage and reactive power control in distribution systems. In the past, settings and parameters of local controllers (such as voltage regulators and switched capacitors) were mainly calculated using off-line studies. However, this approach was seen through as not adequate since it could not provide settings that would be effective to cover an adequately wide range of operating conditions, given the continuous changes in power demand and network configuration [116].

Furthermore, the consequence of the local (uncoordinated) voltage control operation in the distribution systems is that the voltage profile and reactive power flow can be far from optimum. The optimum voltage profile and reactive power flow should however be achieved if the voltage and reactive power equipment are coordinated, similarly to the one in the transmission system [99]. Consequently, the use of a centralized control approach to voltage/var control will enable voltage and reactive power management to be optimal at the system level and not just at a local level.

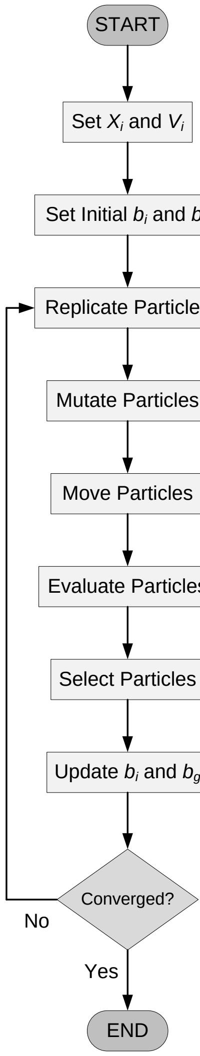

Figure 4-4 – EPSO Algorithm

In order to develop an efficient coordinated method for voltage support in distribution grids, involving the MV and LV levels, the specific characteristics of these MV and LV networks must be considered. Concerning the MV network, a traditional power flow routine may be used to assess the impact of DG and microgeneration. However, for a LV system comprising single-phase loads and microgeneration units that cause phase unbalance, balanced power flow routines are not suitable. For this type of systems, a three-phase power flow must be employed.

Nevertheless, the main problem when dealing with optimizing distribution network operation is the dimension of the distribution system. Given the size of both MV and LV real distribution networks, a full representation of an MV network (including all LV feeders located downstream) is unpractical. Since the dimension of the system may be huge, considering that an MV including the downstream LV networks can have several thousand buses, it becomes practically unfeasible to develop an algorithm using a full model representation of the MV and LV levels, able to operate in a real-time management environment.

Consequently, for the optimization procedure developed in this chapter, the MV and LV networks are considered as being decoupled. In this approach, from the MV point of view, each "active" LV network (*i.e.* microgrid) is considered as a single bus with an equivalent generator (corresponding to the sum of all micro-source generations) and equivalent load (corresponding to the sum of all LV loads) and "passive" LV networks are modelled as a non-controllable load, as shown in Figure 4-5.

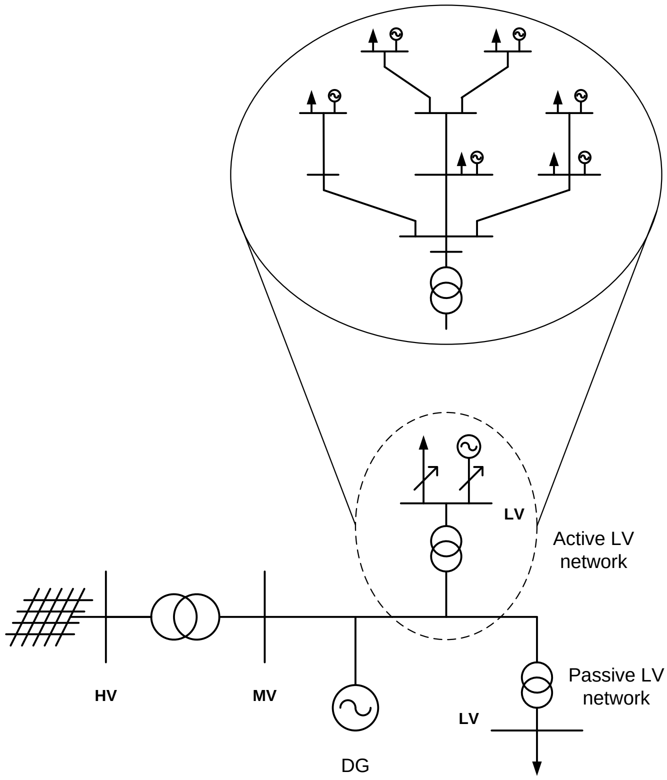

Figure 4-5 – Decoupled Modelling Approach used for the MV and LV Networks

However, the effects of the control actions must be assessed at the LV level, especially in the case of "active" LV networks. This means that a full representation of these networks should be used in order to know the behaviour of the main operation parameters, such as voltage profiles. This is extremely relevant since, as previously seen, voltage profiles in LV networks with large-scale microgeneration integration tend to be high. The decoupled approach followed in this work allows modelling in detail only the LV networks considered critical in terms of microgeneration penetration levels.

Thus, in order to speed-up the control algorithm, an ANN able to emulate the behaviour of the "active" LV network (or microgrid) was included. This option enables the use of the optimization tool employed in real-time operation, by reducing the long simulation times that are required in order to calculate consecutive LV power flows. In fact, the ANN can be regarded as an equivalent model able to reproduce the behaviour of the LV network regarding namely voltage profiles and losses since these are the variables of major concern. Using the ANN, the computational burden and, consequently, the computational time required to run the application can be significantly reduced. Details on the development of the ANN used in this work are presented in Section 4.3.3.1.

The ANN used here for representing the behaviour of the "active" LV network is a type of black-box model as represented in Figure 4-6.

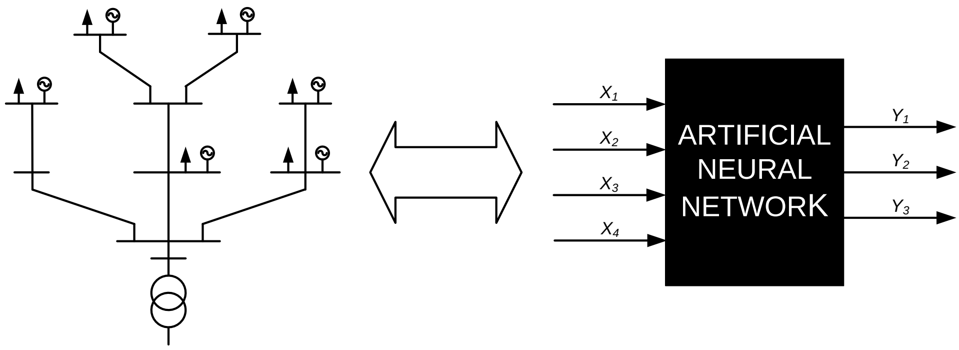

Figure 4-6 – Replacing an Active LV Network (Microgrid) by an ANN equivalent

As a final remark, it must be underlined that no strategy similar to the one proposed in this chapter was found in the available scientific literature. In fact, as seen in Chapter 2, several strategies are available in order to utilize DG capabilities for voltage regulation, typically at the HV and MV levels. Other approaches highlight the possibility of exploiting power electronic interfaces of DG units (located at the HV and MV levels or even at the LV level – microsources) for voltage control. Nevertheless, all these approaches lack the coordination of resources at different voltage levels (MV and LV) in order to ensure an optimized operation of the global distribution system in terms of voltage control.

4.3.3 Artificial Neural Networks

In general form, an ANN is a mathematical or computational model that tries to simulate the structure and/or functional aspects of biological neural networks. These networks can be used to model complex relationships between a series of inputs and outputs or to find patterns in data sets.

ANNs have been widely used and have successful applications in several areas including [117]:

- **Aerospace industry** – for high-performance aircraft autopilot, aircraft control systems and aircraft component fault detectors.
- **Automotive industry** – for automobile automatic guidance systems.
- **Defence industry** – for weapon steering, target tracking, facial recognition and signal/image identification.
- **Telecommunication industry** – for image and data compression and automated information systems.

According to Haykin [118], an ANN can be regarded as an adaptive machine, *i.e.* a massively parallel distributed processor made up of simple processing units, which has a natural propensity for storing exponential knowledge and making it available for use. It is said to resemble the brain in two respects:

1. Knowledge is acquired by the network from its environment through a learning process.
2. Interneuron connection strengths, known as synaptic weights, are used to store the acquired knowledge.

The basic processing unit of an ANN, called a neuron, is presented in Figure 4-7.

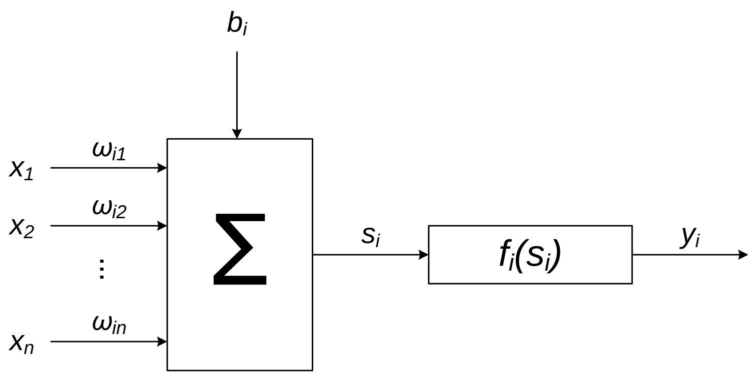

Figure 4-7 – Scheme of a Basic Processing Unit (Neuron) in an ANN

As can be observed, each processing unit i has a set of input variables $x_1, x_2 \dots x_n$ that are transformed as shown below.

$$s_i = \sum_{k=1}^{n} (\omega_{ik} \cdot x_k) + b_i \tag{4-24}$$

Where

x_k is the input variable in the processing unit i
ω_{ik} is the weight of x_k
b_i is a bias parameter

$$y_i = f(s_i) \tag{4-25}$$

Where

y_i is the output variable in the processing unit i
$f(s_i)$ is the activation function

The activation function $f(s_i)$ of a node defines the output of that node given an input or set of inputs and can have several forms. In Figure 4-8, some of the most common forms such as the linear function in (4-26), the hyperbolic tangent function in (4-27) and the logistic sigmoid function[28] in (4-28) are shown.

[28] Both the hyperbolic tangent function and the logistic function are common sigmoid functions, commonly known as "S-shaped" functions.

$$f(x) = x \tag{4-26}$$

$$f(x) = \tanh x \tag{4-27}$$

$$f(x) = \frac{1}{1 + e^{-x}} \tag{4-28}$$

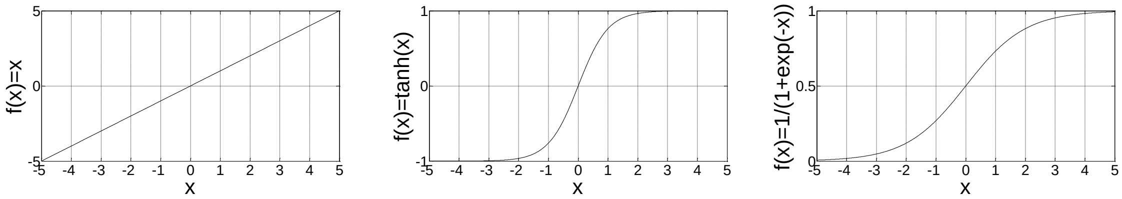

Figure 4-8 –Common Activation Functions for ANNs

The neurons can be connected through a network structure such as the one presented in Figure 4-9. As can be seen, neurons are arranged in different layers and the output of each neuron in a certain layer is one of the inputs to each of the neurons in the subsequent layer. In Figure 4-9, the information flows in only one direction, forward, from the input layer, through the hidden layers (it must be noted that there can be several hidden layers) and to the output layer. Thus, there are no cycles or loops in the network. This type of network is called a feed-forward neural network. The number of hidden layers and the number of neurons are attributes that characterize a neural network and must be defined at the design stage.

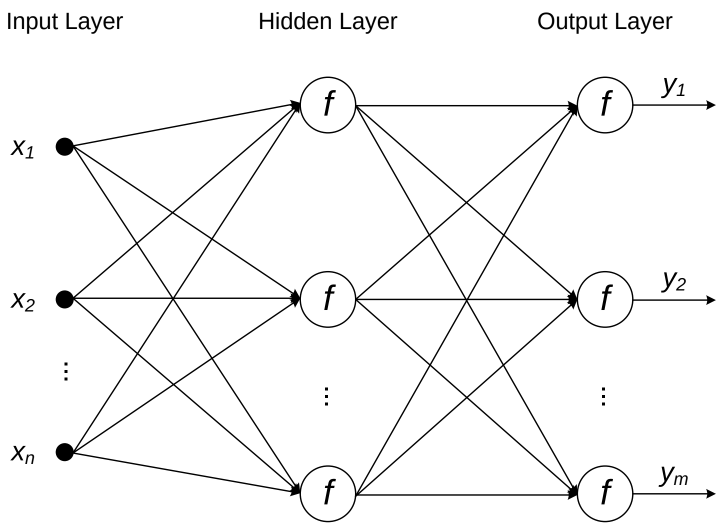

Figure 4-9 – Typical Structure of a Feed-Forward ANN

Once the structure of the ANN is defined, a training stage is required. An ANN can be trained to perform a particular function by adjusting, in an iterative way, the values of the weights and bias parameters shown in (4-24). Typically, ANNs are adjusted, or trained, so that a particular input leads to a specific target output. Figure 4-10 presents the training process for an ANN.

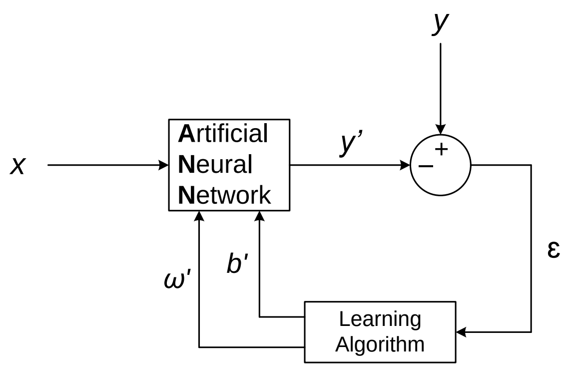

Figure 4-10 – ANN Training Process

As can be seen, in each iteration the actual value of the ANN output y' is compared to the target value y, resulting in an error signal $\varepsilon = y - y'$. This error signal is used to feed the learning algorithm that adjusts the ANN parameters (weights $\omega'$and biases b') in order to minimize the deviation between the target value and the ANN output.

The most common performance function for feed-forward ANNs is the Mean Squared Error (MSE), *i.e.* the average squared error between network outputs and the target outputs, as shown below.

$$E = \frac{1}{N} \cdot \sum_{i=1}^{N} (y_i - y_i')^2 \qquad \textbf{(4-29)}$$

Where

E is the performance function
N is the number of training patterns

Several different training algorithms may be used for feed-forward ANNs. One method that is widely used is the back-propagation technique. This technique calculates the gradient of the error of the ANN with respect to the ANN's weights. The gradient can be then used in a simple stochastic gradient descent algorithm to find weights that minimize the error.

Two different styles of training can be implemented using this strategy: incremental mode and batch mode. In incremental training the weights and biases of the network are updated every once an input is presented to the ANN. In batch training the weights and biases are updated only after all the inputs are presented.

Nevertheless, other algorithms can be used as alternative. For instance, concerning ANN training in batch mode, a Levenberg-Marquardt[29] algorithm can be applied in order to accelerate the training process [119]. This method provides fast convergence, robustness and does not require user-initialization of design parameters such as the learning rate, which has a strong influence on the algorithm performance in its classical implementation [17], [120].

[29] The Levenberg–Marquardt algorithm is a modification of the traditional Gauss-Newton method that ensures fast convergence for training moderate-sized feed-forward ANNs.
For more information see also http://www.mathworks.com/access/helpdesk/help/toolbox/nnet/

4.3.3.1 Artificial Neural Networks for Microgrid Emulation

As previously mentioned, the voltage control scheme presented is intended to be used as an online function, made available to the DSO. Nevertheless, in order to be able to have a simulation tool that can effectively and efficiently optimize the MV and LV networks in a coordinated way, some adaptations to the methodology used in the control algorithm must be made. The main difficulties identified are related to the type of analysis required for the MV and LV levels and from the (potential) large dimension of both these systems.

In order to overcome these difficulties, an ANN able to emulate the behaviour of an “active” LV network in terms of power flows has been developed. Therefore, each “active” LV network can be replaced by an equivalent ANN model in the global optimization procedure.

The utilization of the ANN model enables a considerable speed-up of the algorithm, thus enabling the use of the meta-heuristic tool employed in real-time operation, reducing the long simulation times that would be required in order to calculate consecutive power flows.

In order to build the ANN, the first thing to do is to define the input variables and select the targets that are relevant. The main inputs and outputs chosen for the ANN used here are presented in Figure 4-11.

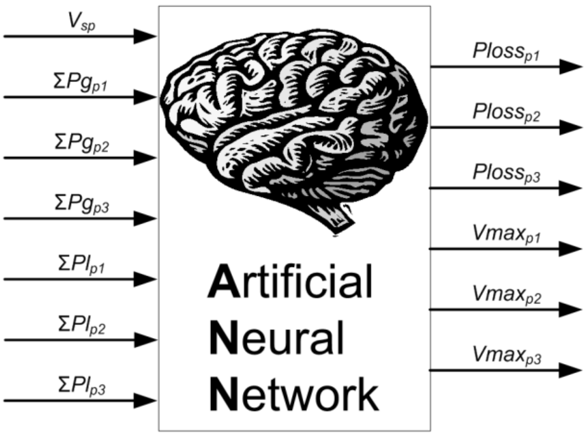

Figure 4-11 – Artificial Neural Network for Microgrid Emulation

Where

V_{sp}	is the voltage at the MV/LV substation
$\sum Pg_{pi}$	is the total active power generation in phase i
$\sum Pl_{pi}$	is the total active power load in phase i
$Ploss_{pi}$	Is the total active power losses in phase i
$Vmax_{pi}$	Is the maximum voltage value in phase i

It was considered above that the main target variables to be observed would be the voltage in each phase and the total active power losses, given the characteristics of the “active” LV network. Since we are considering a decoupled approach, the most significant inputs in order to determine these targets were found to be the voltage value at the connection point between the MV and the LV network and the total load and total generation in each phase.

In order to design the architecture of the ANN, several issues must be considered. First of all, the number of hidden layers and the corresponding number of neurons. According to Fidalgo [121], there are several techniques that can be used to identify an optimal ANN structure. However, in this case, a “trial-and-error” approach was used in order to design the ANN, by varying the number of layers and number of neurons in each layer and evaluating the performance of the model.

Concerning the number of hidden layers, it is known that an ANN with one hidden layer is able to represent any continuous function, with a degree of accuracy depending on the number of neurons in that layer [122]. According to Vasconcelos [122], in practice, it is not very common to have ANNs with more than two hidden layers.

Finally, regarding the number of neurons in the hidden layers, a compromise must be achieved. If few neurons are used, the ANN may not perform well; however, if too many neurons are used, the ANN may lack generalization capability [122].

From the tests that were performed, it was seen that the ANN with best performance was a two-layer feed-forward ANN with sigmoid hidden neurons and linear output neurons. According to [123], this type of ANN can fit multi-dimensional mapping problems arbitrarily well, given consistent data and enough neurons in its hidden layer. In this case, 21 neurons were used in the hidden layer. The structure of the ANN employed is shown in Figure 4-12.

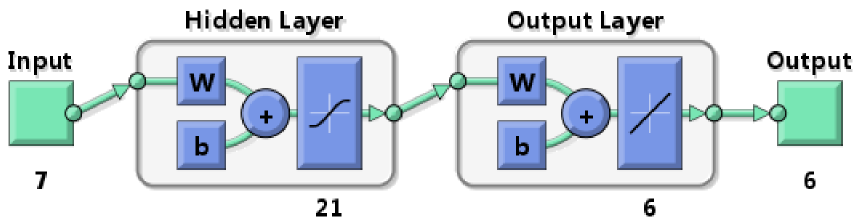

Figure 4-12 – ANN Structure

Still, it must be pointed out that in case there is a change in topology of the “active” LV network, a new ANN must be computed. For instance, this change in network topology or reconfiguration may be originated by adding microgeneration at a particular node of the LV network or by replacing/adding a new line. This procedure is due to the characteristics of ANNs that usually have limited generalization capability, *i.e.* are not suitable for providing good quality results for scenarios fairly different from the ones used for the training procedure. This means that it is necessary to update the data and generate a new data set, followed by a retraining of an updated ANN.

In order to use efficiently the approach developed, it is necessary to automate the procedure of retraining the ANNs. First of all, the main changes that trigger the need for retraining the ANNs must be identified. These changes are mostly changes in the topology of the networks due to the inclusion (or removal) of additional DG, microgeneration units or loads, the set-up (or upgrade) of a line or transformer and expansion of the LV grid.

Different ANNs need to be developed for replacing each "active" LV network. An assessment of the performance of this ANN structure applied to several LV test networks is presented in Chapter 6.

Furthermore, in order to generate the data set corresponding to the inputs chosen to train the ANN, a large number of three-phase power flows must be computed, considering different combinations of the inputs (*i.e.* several values for the voltage reference at the MV/LV transformer, for the power generated by each microsource and for the load) in order to calculate the active power losses and assess the voltage profiles in each of these scenarios. In particular, a careful selection of the data to train the ANN is crucial in order to obtain a reliable model for the network. The performance of the ANN is extremely sensitive to the quality of the data used in the training process[30]. A detailed description of the three-phase power flow algorithm and the scenarios developed is given in the next sections and the assessment of the performance of the ANN for several LV test networks is presented in Chapter 6.

4.3.3.2 Three-Phase Power Flow

A three-phase power flow routine was developed in order to enable the analysis of the steady-state behaviour of a typical LV network, with its specific characteristics, namely concerning phase imbalances. This LV network is expected to include not only single-phase loads but also single-phase microgeneration technologies.

The power flow solution method used here is the one developed by Cheng and. Shirmohammadi in [124] and extended to four-wire systems by Ciric *et al.* in [125]. The latter, which is in fact a generalization of the algorithm presented in [124], is used for three-phase, four-wire radial distribution networks where the neutral wire and the ground are explicitly represented. It uses a general power flow algorithm based on backward-forward technique, which is extremely fast to reach convergence.

It must be noted that this method was designed for radial distribution networks, although it may adapted for weakly meshed networks [125]. Also, the proposed power flow method enables the investigation of the effects of neutrals and system grounding on the operation of real distribution networks.

Concerning the modelling of DG or microgeneration units, these can be represented in one of the following modes, depending on the contract and control status of the generator [124]:

1. In "parallel operation" with the feeder, *i.e.* when the generator is located near and designated to supply a large load with fixed real and reactive power output. The net effect is the reduced load at a particular location.
2. To output power at a specified power factor.
3. To output power at a specified voltage value.

In the context of the power flow algorithm, the generation nodes in the first two cases can be represented as P-Q nodes, which do not require special treatment in the algorithm. In this

[30] One should always bear in mind the pun traditionally employed in computer science "garbage in, garbage out" or GIGO.

work, the generating units were modelled as P-Q nodes since they are considered as RES based on solar power. Furthermore, it was considered that the sources operate at a fixed unitary power factor, meaning that there is no reactive power generation.

Alternatively, the generation node in the third case must be modelled as a P-V[31] node. In this case, special procedures must be used to maintain its voltage magnitude as well as to monitor its reactive power capability. A compensation method using a P-V node sensitivity matrix to eliminate the voltage magnitude mismatch for all P-V nodes developed for three-phase systems is presented in [124]. This option, however, was not used here.

This algorithm was used to generate the data set needed for building the ANN presented in the previous section. A detailed description of the three-phase power flow used in this work is presented in Appendix A.

4.3.3.3 Data Set Generation

In order to obtain the data set required for training the ANN, a three-phase power flow routine must be used under several load and generation scenarios. This procedure must be done in an efficient way since the quality and diversity of data provided to the ANN will be a key factor in order to achieve a good model representation of the microgrid.

In order to obtain these scenarios, a large data set must be generated. These scenarios should cover a large number of operating points and are defined by a combination of parameters, which are assumed to vary continuously. The sampling of these values must be performed in order to obtain a representative set of data that will enable the ANN to reach the required target values.

The sampling of the data can be done according to the following procedure: for generating the data set, random samples of each input variable x_i are obtained within a pre-defined range – defined generally in (4-30) – and resolution $n(x_i)$ for each of the variables, as illustrated in Figure 4-13 for a one-dimensional search space. This approach enables increasing the diversity of operating points obtained.

$$x_i \in [\min(x_i), \max(x_i)] \qquad \textbf{(4-30)}$$

with $i = 1,2,\ldots,N$

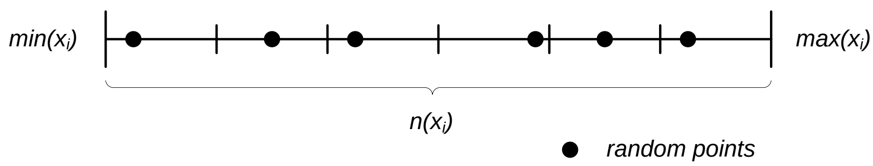

Figure 4-13 – Randomly Generated Points (One-Dimension)

[31] Not to be confused with PV (photovoltaic). P-V nodes are used in power flow studies to represent generator buses, where it is assumed that the real power generated and the voltage magnitude are known *a priori*.

The range and resolution considered for each variable are presented in Table 4-1.

Table 4-1 – Range and Resolution for Variable Sampling

Variable	Range [p.u.]	Resolution
Voltage Reference	[0,9; 1,1]	0,05
Total Generation	[0; 1]*	0,02
Total Load	[0; 1] **	0,02

* Relative to total generation installed capacity
** Relative to total load installed capacity

Therefore, this method divides the n-dimensional hyperspace of all possible operating points into several hyper-cells. Inside each of these hyper-cells, a random value is then found for each variable. In this case, for each hyper-cell, a pre-defined number of samples in the 7-dimension hyperspace is obtained randomly.

This procedure was adopted since it allows exploring the solution space more thoroughly, which will have direct reflections on the quality of the results provided by the ANN. The approach adopted in this work is similar to the structured Monte Carlo simulation presented in [17] and [126], following previous work by Vasconcelos [122].

The three-phase power flow algorithm developed is used to generate all inputs and targets for the ANN. For each scenario generated, a set of inputs and targets is defined, corresponding to one operating point, using the procedure described above. Naturally, should the three-phase power flow be unable to achieve convergence, this operating point should be discarded from the data set. However, this situation has not occurred for any of the computations performed. Consequently, for each ANN, a total of 8192 different operating points were generated.

The inputs and targets were mapped to the interval [0; 1] in order to feed the ANN with normalized values. Assuming that input x has only finite real values, and that the elements of each row are not all equal, the following algorithm was used:

$$y = \frac{(y_{max} - y_{min}) \cdot (x - x_{min})}{(x_{max} - x_{min})} + y_{min} \tag{4-31}$$

Where

y is the output variable
x is the input variable
y_{max} is the maximum value for y
y_{min} is the minimum value for y
x_{max} is the maximum value for x
x_{min} is the minimum value for x

The ANN was trained with the Levenberg-Marquardt back-propagation algorithm. The input vectors and target vectors are randomly divided into three sets as follows:

- 60% are used for training;
- 20% are used to validate that the network is generalizing and to stop training before over-fitting;
- The last 20% are used as a completely independent test of network generalization.

4.3.4 Development of the Tool

The voltage support functionality described in this chapter is intended to be used as a real-time application that will be able to assist the DSO in managing the distribution network.

The coordinated voltage control means that the voltage and reactive power control equipment available is adjusted remotely, based on wide area coordination, in order to ensure safe operating conditions based on load forecasts and DG and microgeneration dispatch for the next operation period. Thus, optimal voltage/var control in distribution systems requires the solution of an optimization problem for the next operation period of one-hour to minimize system losses and microgeneration shedding, while limiting the number of OLTC hourly switching operations and ensuring secure system operation.

The development of the tool developed involves the following steps:

- Generating off-line generation a large data set containing data on the steady-state behaviour of an "active" LV network (microgrid) based on a three-phase power flow algorithm under several operating conditions (considering several different load and generation scenarios);
- Training and evaluating the performance of the ANN selected in order to assess the main variables (namely voltage levels and losses) resulting from the several power flows as a function of the voltage reference and total load and generation in each phase;
- Exploiting the ANN tool for identifying the control actions that should be undertaken by the DSO in order to ensure a secure and stable operation of the MV distribution system for each operating period.

The tool was developed in the MATLAB© environment using MATLAB© R2009b (version 7.9.0). The main algorithm running a power flow at the MV level uses MATPOWER©[32], a power system simulation package developed by Zimmerman, Murillo-Sánchez and Gan. The power flow algorithm used in MATPOWER© (version 3.2) implements a Newton-Rhapson method for solving the power flow problem using a full Jacobian, which is updated at each iteration [127].

The three-phase power flow for LV networks using a backward-forward technique was also implemented in MATLAB©. This algorithm provided the inputs for the ANN model developed. The Neural Network Toolbox© from MATLAB© was used to design and develop the ANN. The

[32] MATPOWER – A MATLAB Power System Simulation Package
For more information see http://www.pserc.cornell.edu/matpower/

inputs and targets of the ANN were normalized using the *mapminmax©*[33] function available in the Neural Network Toolbox© for MATLAB©.

A general overview of the voltage/var control algorithm implemented for each one-hour period is shown in Figure 4-14.

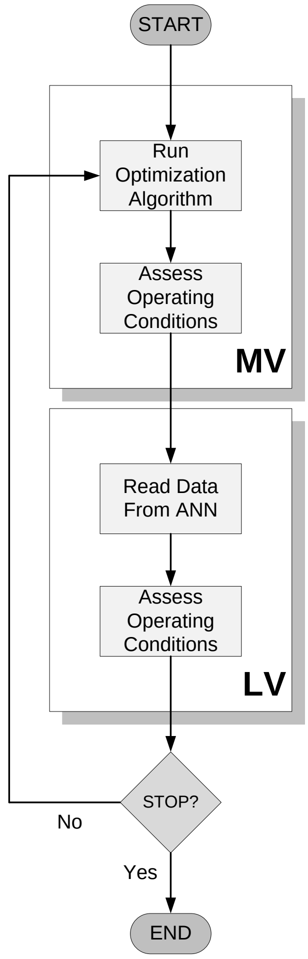

Figure 4-14 – Voltage/var Control Algorithm

The MV and LV levels for the voltage/var control are clearly identified in the figure. As previously stated, the algorithm runs at the MV level, using the optimization algorithm chosen (in this case, EPSO) and uses the ANN in order to assess operating conditions at the LV level in an iterative way. The algorithm reaches the end – stop criterion – after it has been verified that there are no improvements to the value of the objective function during a certain number of iterations (*e.g.* 200) or after reaching a maximum pre-determined number of iterations (*e.g.* 1000).

In conclusion, the approach proposed here considers that an effective voltage control scheme requires coordinated action of all resources available in the distribution network in order to achieve optimum performance of the overall distribution system. These actions include defining set-points for MV-connected DG units, microgenerators, OLTC transformers and

[33] The function *mapminmax©* processes matrices by normalizing the minimum and maximum values of each row to [Y_{MIN}; Y_{MAX}].

capacitor banks. Furthermore, the hierarchical control system proposed in Chapter 3 is seen as the ideal basis for implementing new advanced functionalities for network operation, including voltage regulation. The communication infrastructure designed to support such a system will provide the means necessary to implement this type of coordinated actions.

4.3.5 Integration of the Voltage Control Module

As previously seen, the algorithm developed for voltage/var control in distribution networks is designed to be used as an online function available for the DSO. This algorithm is intended to be integrated as an independent software module that will be housed in the CAMC.

The CAMC, that includes several key functionalities for the management and operation of the distribution system, is intended to be installed at the HV/MV substation. As presented in Chapter 3, the CAMC is the controller in charge of the MV and LV distribution systems and operates under the responsibility of the DSO. The inclusion of some management functionalities at the CAMC allows relieving the central DMS, following a rational of decentralized operation based on partial autonomy of local controllers.

Figure 4-15 illustrates the several functionalities for control and management of the distribution system included in software packages housed in the CAMC, including the voltage control algorithm developed here.

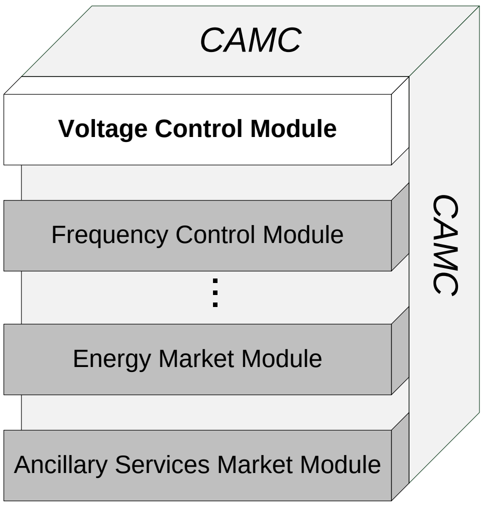

Figure 4-15 – Voltage Control Module included in the CAMC

Exploiting a smart metering infrastructure, which is assumed to be available, the CAMC is able to collect critical information from the several devices in the network, namely data from load and RES forecast modules and generation dispatch, in order to assess voltage profiles, branch overload levels and active power losses. Using this information, the voltage control algorithm is run and, after it has successfully terminated, produces a set of commands in the form of set-points. These commands are then sent to the several devices such as DG units, microgeneration units (via the corresponding MGCC), OLTC transformers and capacitor banks. This procedure should run cyclically and in an automated way, under the supervision of the DSO.

The topology and structure of the MV and LV distribution systems is also periodically updated in order to provide the several modules with data on the current status of the grid, including all devices such as DG units, microgenerators, loads, switches, *etc.*

4.4 Summary and Main Conclusions

The expected increase of DG and microgeneration penetration in distributions networks may pose serious operational problems for the DSO, namely regarding voltage control. The major concerns are related to the voltage rise effect as a result of massive integration of these units in the distribution system. Furthermore, traditional voltage regulation methods are not suited for effectively tackling this problem. Consequently, new methods must be developed that take full use of the resources available (especially DG and microgeneration units) and that take into account the specific characteristics of distribution networks.

It was seen that, in the case of LV networks, both active and reactive power control is needed for an efficient voltage control scheme. In some extreme cases, due to the voltage rise effect, it may be necessary to spill some local generation in order to avoid operational problems.

In order to develop an efficient coordinated method for voltage support in distribution grids, involving the MV and LV levels, these specific characteristics of MV and especially LV networks must be considered. Therefore, a novel approach to voltage support has been developed. The voltage/var control problem can be treated as a hierarchical optimization problem that must be analysed in a coordinated way between the MV and LV levels. This approach aims at optimizing operating conditions by taking full use of DG, microgeneration, capacitor bank and OLTC transformer control capabilities. The possible range of control actions identified include adjusting reactive power generation from MV-connected DG sources, curtailing microgeneration, changing capacitor bank settings and adjusting OLTC transformer settings. Although in the formulation, MV and LV networks are considered as decoupled, coordination between these two LV levels is guaranteed. The innovative formulation presented in this chapter allows tackling the voltage/var control problem in future distribution networks, comprising large amounts of DG (at the MV level) and microgeneration (at the LV level).

Considering the specifics of the problem, particularly the fact that it comprises both discrete and continuous variables, a meta-heuristic approach – EPSO – was chosen.

The complexity of the problem, especially given the dimension of real MV and LV networks, requires introducing some simplifications in the representation of the distribution system in order to avoid long simulation times. Consequently, an ANN was used to represent the behaviour of a LV network comprising microgeneration, which allowed speeding-up the algorithm considerably.

The combination of the meta-heuristic optimization engine together with an ANN equivalent representation of the microgrid is thought to allow the use of this approach for real-time under future DMS environments. Consequently, the resulting algorithm represents an integrated control approach that will facilitate large-scale integration of DG in an efficient way that may be suitable for a tool to be integrated in a control software module to be used by the DSO.

"Alice laughed. «There's no use trying,» she said: «one CAN'T believe impossible things.»
«I daresay you haven't had much practice,» said the Queen.
«When I was your age, I always did it for half-an-hour a day.
Why, sometimes I've believed as many as six impossible things before breakfast. There goes the shawl again!»"

Alice talking to the Queen in "*Through the Looking Glass*" by Lewis Carroll (b. 1832 – d. 1898)

Chapter 5 – Ancillary Services Market for Voltage Control

In this chapter, a proposal for an ancillary services market framework addressing voltage control in multi-microgrid systems is presented. In this case, ancillary services markets are considered to be independent and operated separately from the main energy market, with different procurement and remuneration mechanisms. This var market proposal for distribution systems can be adopted to manage DG units and microgrids. This approach is designed for normal interconnected operation, where each player is given the opportunity to submit its bid to the var market and the market settlement is performed using an OPF-like approach in order to minimize the price of reactive power purchased by the DSO. This market is based on var capacity use and runs daily after the scheduling of the generation units for a period of operation, typically one day.

5.1 Introduction

During the last two decades, the restructuring of the electric power industry has caused a shift in paradigm in terms of operation philosophy and control strategies. Certain activities that were previously considered part of the integrated electricity supply (such as voltage control and frequency control) are now regarded as separate services and often independently managed and accounted for [128]. These services are called ancillary services.

As seen in Chapter 2, ancillary services are essential in order to support the transmission of electric power from the generators to the consumers while meeting safety, security and reliability requirements for power system operation. These services must be provided by generation, transmission and control equipments and may be mandatory or subject to competition [62]. In the future, ancillary services provision should involve also the DSO and the distribution infrastructure, in addition to the TSO and the transmission system. Moreover, generation should not be the only entity providing ancillary services since demand response and storage equipments may also be exploited in order to provide some of these services [91].

According to Kueck *et al.* in [65], one of the most exciting prospects of the distribution system of the future will be its ability to provide ancillary services. This has mainly to do with the fact that supplying these services locally (especially concerning voltage regulation and reserve provision) can be more efficient than supplying them from distant generation units. These services may be provided by both loads and DG units in response to market signals. In order to implement this vision, in addition to an "intelligent" distribution system, it will be necessary to have an automated market system. The creation of this market structure will be able to ensure at least some demand elasticity in the load, which is something not common presently[34].

[34] An elastic demand means that some customers may cut back their consumption during periods of supply shortage and/or high prices.

In the future, electricity supply is expected to depend heavily on DG and, particularly, on RES. Presently, most of DG units are limited to injecting energy into the distribution system. Without the possibility of involving DG in network operation, these units (especially the ones based on renewable and intermittent sources such as PV and wind generation) will affect significantly network management and control procedures considering scenarios with high penetration levels of these technologies. In order to overcome these problems, it is expected that these units may be able in a near future to contribute to network operation, thus ensuring a more sustainable and reliable system. The main drawbacks that are usually pointed out for rejecting DG participation in network operation are its relatively small size, unreliability and costly operation. However, by aggregating some of these resources, it is possible to create larger market players, which can help mitigating many of their apparent disadvantages [91]. In particular, through the VPP concept, aggregated DG units and loads may be able to participate in electricity markets and provide ancillary services. This can be achieved by exploiting the technological control capabilities of DER, in particular through their power electronic interfaces.

The VPP concept and the possible services that may be provided by DER are shown in Figure 5-1, both from a technical perspective and from a market perspective. The DER scattered across the distribution system are managed through aggregators in an integrated way, using a communication infrastructure. This enables DER to provide several services by participating in the electricity market and by providing ancillary services such as reserve provision, voltage control and congestion management. Therefore, a coordinated control approach must be employed to efficiently manage DER. In this context, the microgrid and multi-microgrid concepts as presented in Chapter 2 and Chapter 3 may be exploited.

Microgrids can play a key role here since the microgrid concept, and its corresponding control architecture, should be based on the utilization of a smart metering infrastructure. This infrastructure enables taking full use of distributed control of devices both from the generation and demand side, thus providing a flexible framework for the implementation of energy and ancillary services markets. This will enable real-time price control for microgrids for market issues as well as for system operation.

From the multi-microgrid system perspective, the coordination of multiple microgrids and other DG sources and loads at the MV level can be attained by exploiting the VPP concept: by aggregating components and operating as VPPs, microgrids are able to bid and offer not only energy but also ancillary services to the external system. Within the microgrid, the MGCC is responsible for coordinating all DER located in the LV network by managing responsive loads and microgenerators or storage devices.

Consequently, competitive markets opened to DER participation for providing both energy and ancillary services should be encouraged since they may contribute to improve overall efficiency and facilitate competition between all players in the electrical power system. In particular, ancillary services markets are regarded as a great opportunity for both DG and microgrids, especially for voltage control and reserves [5], [33], [91].

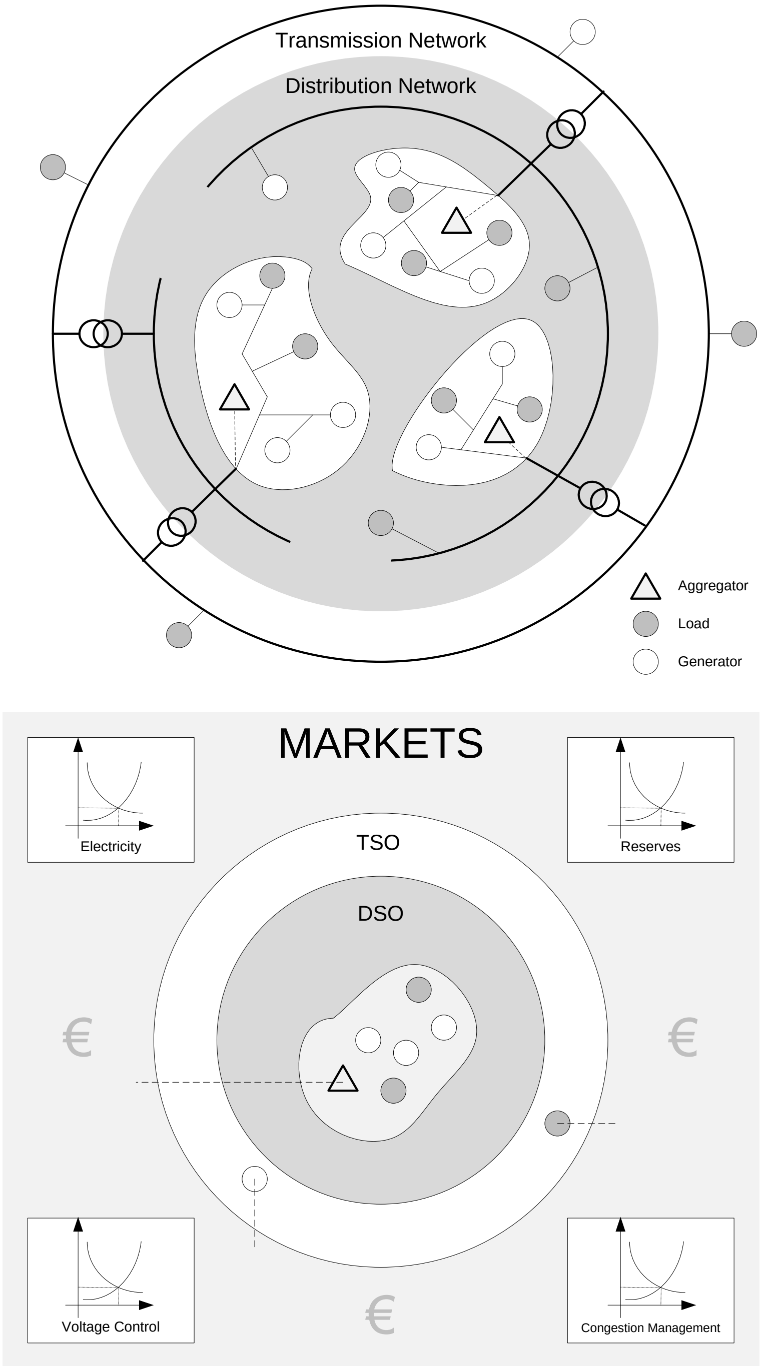

Figure 5-1 – VPP Concept from a Technical Perspective and from a Market Perspective (adapted from [91])

In the design of competitive markets for energy and ancillary services two distinct approaches may be followed: simultaneous auctions for energy and ancillary services (integrated approach) and independent markets for energy and ancillary services (unbundled[35] approach) [129].

[35] Under the paradigm of a liberalized electricity system, unbundling requires business separation between the company that controls the network and other activities such as generation and commercialization to final consumers.

In the first approach, market products are procured simultaneously through central auctions. The incentive for developing integrated systems is to realize gains from tight coordination in daily operations, while strengthening system reliability. The basic argument for integrated systems is that optimization is necessary to minimize the total costs of coordinating generation, transmission, and reserves to meet demand and ensure reliability [129]. In [129], Wu *et al.* present an OPF formulation for procuring, pricing, and settling energy and ancillary service in simultaneous auctions by integrated market systems. Furthermore, an analysis of the characteristics of the prices defined by the resulting Lagrange multipliers[36] is made.

In the second approach, market products are procured sequentially through central auctions. The initial market is the energy market, followed by a transmission market to manage branch overloads and by a market for ancillary services to conform to mandated reliability criteria. The forward markets are followed by a real time market in which the SO uses ancillary services and supplemental energy offers to balance the system in real-time [129]. Participation in each market is voluntary so that traders can move freely from one market to another.

In addition, bilateral contracts may also be used not only for energy trading but also for ancillary services provision, which is the traditional approach for the voltage support service [73]. These contracts may co-exist with both energy and ancillary services markets.

Concerning voltage control, reactive power supply is essential in order to maintain system security in power systems. In the new unbundled organization of electricity markets, voltage and reactive power control is usually integrated in the provision of ancillary services. Therefore, there is a need for an improved regulatory model to address reactive power and voltage control services in a scenario of restructuring and re-regulation of power systems. In addition, new competitive mechanisms are needed in order to guarantee system security together with a minimization of operation costs. Following the liberalization process in energy markets, ancillary services will have separate procurement and remuneration mechanisms [73].

In [128], Zhong *et al.* review several distinct methods for handling reactive power within the market framework following re-regulation[37] in several markets from different countries around the world. They observe that while in many of the markets, proper financial compensation mechanisms exist to compensate the providers for their service, in some others reactive power is still handled through regulatory frameworks and technical operation guidelines.

Nowadays, the integration of large amounts of DG poses new additional challenges for voltage control. Usually, generation units are expected to be the main service providers, although other var sources can also procure the service. The task of the SO is to define the volume of service for the participants in the energy market. In addition to this, the SO must also define

[36] In mathematical optimization, the method of Lagrange multipliers (named after Joseph Louis Lagrange) provides a strategy for finding the maximum/minimum of a function subject to a set of constraints.

[37] Although the authors use the term “deregulation”, in this thesis the preferred terminology is “re-regulation”.

who will participate in the ancillary services market, in this case for the voltage control service, how is the service going to be provided and how is it regulated.

The main products identified for the voltage control ancillary service are the reactive power capacity and its use [72], [73]. Under a competitive framework, a market proposal was developed for the reactive power use, based on a daily market following the dispatch of the generation units. Reactive power capacity may also be remunerated through a market mechanism or bilateral contracts, although the definition of this remuneration falls outside the scope of this thesis.

It must be stressed that some parts of the work presented in this chapter have already been included in a report for the More MicroGrids project [78].

5.2 Mathematical Formulation

The ancillary services market for voltage control can be a day-ahead market that follows the scheduling of generation (including forecasts for RES) for the next day, under the responsibility of the DSO. Therefore, in order to perform the market settlement, the DSO must assess the operating conditions in a portion/area of the distribution network considering the var bids provided by the several players that wish to participate in the ancillary services market for voltage control.

An OPF-like routine is used in order to define the cleared bids from the market players, according to the following general formulation:

$$min\ f(x) \tag{5-1}$$

$$subject\ to$$

$$g(x) = 0 \tag{5-2}$$

$$h(x) \leq 0 \tag{5-3}$$

$$x_{min} \leq x \leq x_{max} \tag{5-4}$$

Where

x is the vector of state variables
$f(x)$ is the objective function
$g(x)$ is the set of equality constraints
$h(x)$ is the set of inequality constraints
x_{min} is the vector with the minimum admissible values for the state variables
x_{max} is the vector with the maximum admissible values for the state variables

Several different objective functions may be used in an OPF formulation to address var valuation. The most common ones are minimizing active power losses and minimizing var purchase [73].

The main equality constraints considered in (5-2) are usually the non-linear active power balance equations and reactive power balance equations.

The inequality constraints shown in (5-3) are generally related to apparent power flow limits of branches. The constraints in (5-4) concern other technical and operational limits such as bus voltage limits and active and reactive power generation limits.

5.2.1 Participation in Voltage Control Services

The SO is responsible for the operation of the whole distribution system, which means maintaining the network within safe and secure operation limits by exploiting the resources available in the network from other owners, such as DG sources. Under an unbundled scheme, the SO answers to a regulator and receives certain incentives in order to manage efficiently system operation attending to the needs of the customers.

At the higher voltage levels of the distribution system, the ancillary service for voltage control is closely related to reactive power generation (or absorption, depending on the characteristics of the network and loads and on the period of the day). Therefore, the role of the SO is to assess the needs in terms of var needs in order to comply with security and operational requirements.

Also, the SO defines a set of operating procedures, which are usually based on the control of voltage within certain pre-defined safety margins, in order to evaluate the needs of var support and select the var sources that participate in the voltage control ancillary service.

The procurement of var support to voltage control by the different sources can be defined by the SO as mandatory or optional participation in the service [73]:

- **Mandatory requirements** – all service providers have the obligation to ensure a certain amount of var capacity to procure the service. Although mandatory requirements are easy to define and implement, there should be some consideration of the different characteristics of the several var sources.
- **Optional requirements** – the var sources have no obligation to provide the service but can optionally participate in the service. This option guarantees a fair treatment for all service providers involved.

Furthermore, the main products associated to the ancillary services market for voltage control must be identified. Two main products can be identified for each source participating in the service [72], [73]:

- **Installed var capacity** – can be defined as the potential reactive power capacity that may be used in the voltage control ancillary service. This capacity can be measured in reactive power (Mvar) and is mostly related to investment costs, which correspond to the biggest cost share for most sources and can be considered as fixed costs.

- **Use of the var capacity** – corresponds to the real-time use of the installed var capacity. This product can be measured in energy (Mvar.h). The cost of this product reflects mostly the loss-of-opportunity cost if, for instance, a generator has to reduce its active power output in order to provide more var capacity, thus representing a loss of revenues in the active power market.

Many of the proposals for var markets available in the scientific literature are based on reactive power capacity markets. A comprehensive review of the state-of-the-art on different var capacity market proposals can be found in [73].

In [73], Frías proposes an original market structure for the voltage control and reactive power management ancillary service, designed for reactive power capacity, based on an annual auction. Since voltage control, unlike frequency, is mostly a local problem, the global voltage control problem can be simplified by dividing it in a set of local voltage control sub-problems, which are associated with smaller portions of the power system. This approach has been widely used for secondary voltage control approaches such as the one proposed by Lagonotte *et al.* for the case of the French electrical power system [130]. Under this assumption, the optimization problem for the var capacity market is decomposed into a set of sub-problems, where each sub-problem will cover a smaller electric area, thus reducing the number of market participants.

In [72], Ahmed *et al.* present a method for the simulation and analysis of alternative reactive power market arrangements based on combined reactive power capacity and energy payments. The value of reactive power support, in terms of both capability and utilization, of each particular generator is quantified using a developed security constrained reactive optimal power flow. According to [72], it is foreseen that in the future reactive power service will be provided on a competitive basis only.

Finally, remuneration alternatives must be found. Three main approaches are usually considered:

- **No payment** – in this case, selected var suppliers are not compensated for providing the service.
- **Regulated price** – the regulator must determine a compensation for the service providers, usually by using the average costs of the service. The total remuneration is obtained by multiplying the regulated price and the volume of service allocated (either for var capacity or var use).
- **Market price** – service providers participate in the market and decide the volume and price of service they wish to attain. Active power markets and some ancillary service markets, such as voltage control or reserve provision, can be managed using this remuneration alternative.

The remuneration alternatives may be different according to the product considered. Again in [73], Frías proposes a market structure designed for reactive power capacity (based on an annual auction) while the use of the capacity is remunerated through a regulated price.

5.2.2 Market Proposal for Voltage Control

The approach developed in this thesis is to transpose some of the concepts that are traditionally used in the transmission systems to the reality of new distribution systems, given their specific characteristics.

For the model proposed in this thesis, the main product of the ancillary services market for voltage control is var utilization. In normal operating conditions, market participation will be optional for all var sources. Nevertheless, service providers that do not wish to participate in the market may be required, if necessary, to provide reactive power receiving a default payment. The DSO will run an ancillary services market for voltage control for the distribution system that accommodates the var bids from the several players and distributes the var needs among them in order to satisfy the var requirements. This proposal is based on a day-ahead ancillary services market for voltage control. This market should run after the scheduling of the main generation units and be based on forecast data for RES and load for the next period of operation. Nevertheless, at distribution level, it may be difficult to have quality results from the short-term forecast tools for RES and load for a 24-hour horizon since the forecast errors may be too big. This issue must be thoroughly analysed when defining the period of operation.

In this model, the DSO will act as the sole buyer of var and is responsible for the market settlement. In order to achieve the market settlement, the bids from the several var sources are sorted in order to meet the requirements for reactive power demand for each hour of the period of operation considered (*i.e.* one day), which should be set by the DSO. This procedure is illustrated in Figure 5-2.

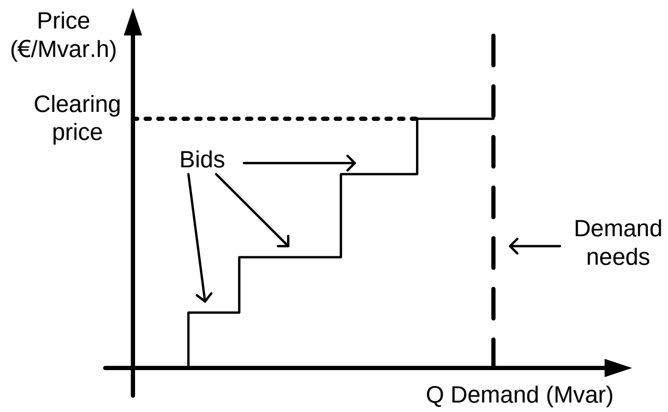

Figure 5-2 – Day-Ahead Market Structure for Voltage Control for each Hour

Service providers for var capacity use are paid according to the market price. The type of pricing adopted for the ancillary services market for voltage control is based on uniform prices equal to the bid of the marginal unit, *i.e.* each unit is remunerated at the market clearing price.

A summary of the proposal for remunerating the var capacity and var use products is presented in Table 5-1.

Table 5-1 – Remuneration Alternatives for var Capacity and var Use

Installed var Capacity		Use of the var Capacity	
Normal Operation*	**Emergency Operation****	**Normal Operation***	**Emergency Operation****
Market price	Regulated price	Market price	No payment

*** Optional**
**** Mandatory**

As previously discussed, a long-term market for var capacity may also be established but is considered to be out of the scope of this work.

5.2.3 Market Players

Several different players may wish to access the var market. DG units directly connected to the higher voltage levels of the distribution system may wish to bid their reactive power generation capacity or, alternatively, some of the reactive power required by the DSO may be bought from the upstream HV distribution network. New players that may also be able to play in this market are microgrids. Their bidding should be submitted through the corresponding MGCC, which acts as an aggregator of microsource capacities and collects the offers from the several microgeneration units within the microgrid. Furthermore, reactive power compensation devices (such as capacitor banks, SVCs and STATCOMs), which are not property of the DSO, are also able to submit their bids to the var market.

Therefore, the main var supplying sources, which can be considered as control variables in this formulation, are:

- HV network (if available);
- DG units;
- Microgrids;
- Reactive power supplying equipments (capacitor banks, SVCs, STATCOMs, *etc.*).

5.2.4 Market Bids

The several players that wish to participate in the ancillary services market for voltage control must provide their bids to the DSO, which is in charge of market settlement. The players willing to enter the var market can organize their bids in blocks: each pre-determined amount of reactive power (Mvar) at a rated price for each of the 24 hours of the next day, as shown in Figure 5-3.

This means that a certain market player can offer an amount of Q_1 Mvar to the market at a price p_1 €/Mvar.h, an amount of Q_2 Mvar at a price at p_2 €/Mvar.h, an amount of Q_3 Mvar at a price at p_3 €/Mvar.h and so on.

Consequently, all market players are able to define the value they wish to receive for providing the service. The bids of the players are then submitted to the market and the DSO will select the most economic offers in order to ensure the required var demand.

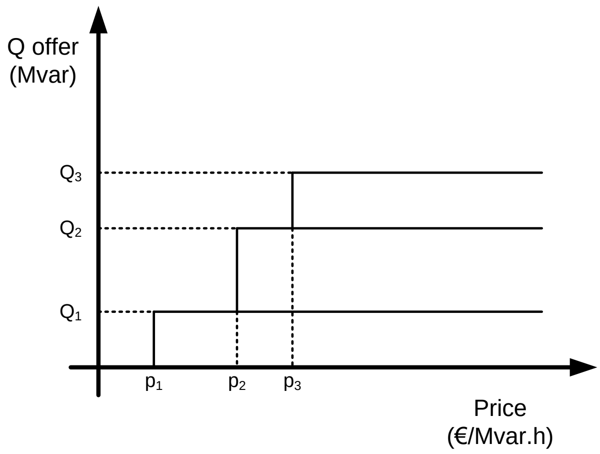

Figure 5-3 – var Bids (Including 3 Capacity Blocks Offered)

5.2.5 Objective Function

It is assumed that DSO is the single buyer that purchases the var support from different independent var suppliers. In order to implement the market settlement, the DSO needs to collect all var bids from the market players. Its main goal should be to minimize the purchases of var capacity, considering certain operational and security criteria.

Therefore, the objective function considered for the ancillary services market for voltage control can be formulated as presented below.

$$min \sum_{j=1}^{M} p_j^{bid} \tag{5-5}$$

Where

p_j^{bid} is the price of the reactive power bid from unit *j*

In the market proposal presented here, the dispatch of active power for every hour is assumed to be already defined. Therefore, active power related costs do not appear in the objective function as shown in (5-5).

5.2.6 Constraints

As in Chapter 4, the constraints used here can be separated into two distinct groups:

- Equality constraints;
- Inequality constraints.

The first group includes the traditional power flow equations, considering a full AC power flow model, whilst the second group is mainly related to operation limits, such as admissible bands for voltage.

5.2.6.1 Equality Constraints

The equality constraints that must be verified correspond to the power flow equations considering a full AC power flow model, as presented below.

$$P_i^G - P_i^L = \sum_{k=1}^{N} V_i \cdot V_k \cdot (G_{ik} \cdot \cos\theta_{ik} + B_{ik} \cdot \sin\theta_{ik}) \quad \textbf{(5-6)}$$

$$Q_i^G - Q_i^L = \sum_{k=1}^{N} V_i \cdot V_k \cdot (G_{ik} \cdot \sin\theta_{ik} - B_{ik} \cdot \cos\theta_{ik}) \quad \textbf{(5-7)}$$

With

$$Q_i^G = \sum_{j=1}^{M} Q_{ij}^{bid} + \sum_{j=1}^{M} Q_{ij} \quad \textbf{(5-8)}$$

Where

P_i^G, P_i^L is the active power generation/consumption at bus i
V_i is the voltage at bus i
G_{ik} is the real part of the element in the Admittance Matrix (Y_{bus}) corresponding to the i^{th} row and k^{th} column
B_{ik} is the imaginary part of the element in the Y_{bus} corresponding to the i^{th} row and k^{th} column
θ_{ik} is the difference in voltage angle between the i^{th} and k^{th} buses
Q_i^G, Q_i^L is the reactive power generation/consumption at bus i
Q_{ij}^{bid} is the reactive power generation corresponding to the bid of unit j at bus i
Q_{ij} is the reactive power generation of unit j at bus i not offered to the var market

In this case, reactive power generation not offered to the var market corresponds to bilateral contracts.

5.2.6.2 Inequality Constraints

Inequality constraints are usually associated to physical limits of devices. The main inequality constraints considered in the formulation of the OPF-like routine are presented below.

$$S_{ik} \leq S_{ik}^{max} \quad \textbf{(5-9)}$$

$$V_i^{min} \leq V_i \leq V_i^{max} \quad \textbf{(5-10)}$$

$$Q_i^{min} \leq Q_i^G \leq Q_i^{max} \quad \textbf{(5-11)}$$

Where

S_{ik} is the apparent power flow in branch ik
S_{ik}^{max} is the maximum apparent power flows in branch ik
V_i is the voltage at bus i

V_i^{min}, V_i^{max} is the minimum and maximum voltage at bus i
Q_i^G is the reactive power generation at bus i
Q_i^{min}, Q_i^{max} is the minimum and maximum reactive power generation at bus i

Note that no restriction similar to (5-11) is included for active power generation, since it is assumed that active power levels are already defined before launching the ancillary services market for voltage control.

5.3 Development of the Approach

As previously mentioned, in order to perform the market settlement, an OPF-like problem must be solved, which can be formulated as a non-linear minimization problem with no discrete variables or controls. More information on the optimization algorithm employed, as well as details on defining operating scenarios and computing var demand for the day-ahead, are presented in the following sections.

5.3.1 Optimization Algorithm

Following the traditional formulation, minimization problems are generally formulated as shown in (5-1). The traditional approach for solving these problems is through the gradient of the function $f(x)$ as follows:

$$\nabla f(x) = 0 \tag{5-12}$$

Where

$\nabla f(x)$ is gradient of $f(x)$

If the problem at hand has constraints, such as the ones presented in (5-2) and (5-3), then these must be incorporated in (5-12), as presented next:

$$\nabla f(x) + \sum_{i=1}^{m} \lambda_i \cdot \nabla G_i(x) = 0 \tag{5-13}$$

$$\lambda_i \geq 0 \tag{5-14}$$

for $i = 1, \dots, m$

Where

λ_i are the Lagrange multipliers (non-zero only if the constraints are active at x)
$G_i(x)$ are the constraints (equality and inequality constraints)

These equations are known as the Kuhn-Tucker equations and many non-linear programming algorithms for computing the Lagrange multipliers directly are widely described in the scientific literature and represent only necessary conditions for the solution (sufficient conditions must be later verified).

Nevertheless, the efficiency of this method can be significantly improved if a quadratic approximation to the function $f(x)$ is used when computing in a point (x_0) near the minimum of the function, as shown in (5-15):

$$\Delta f(x) = f(x) - f(x_0) \cong h.\nabla f(x_0) + \frac{h^2}{2}.\nabla^2 f(x_0) \quad \textbf{(5-15)}$$

Where

x is the running point
x_0 is the point near the minimum of $f(x)$
h is the (multidimensional) increment $x - x_0$
∇ is the gradient
∇^2 is the Hessian

In this case, since the first derivative is almost zero, the quadratic term is a good approximation to the function in the proximity of x_0. The approximate values of $\nabla f(x_0)$ and $\nabla^2 f(x_0)$ can be linearly determined from the knowledge of a sufficient number of $f(x)$-values around x_0; if these values are superabundant, a compensation (gaussian) procedure may be used in order to increase accuracy. The (approximate) minimum $f(x^*)$ of $\Delta f(x) = f(x) - f(x_0)$ may then be directly computed from the (approximate) quadratic function. This procedure is iterated until either (i) no variation occurs in the solution or (ii) a pre-set number of iterations is performed (forced ending).

Most practical algorithms start by using the gradient (steepest descent) method and, when the gradient is nearly zero, increase efficiency by resorting to a quadratic approximation. This type of methods falls into a category usually known as Sequential Quadratic Programming (SQP).

As in any other optimization method, several issues should be taken into account. These issues include handling accuracy problems, defining step size and determining stop criteria, which are intimately related not only to the method chosen but also to the implementation of the method, namely programming language and machine precision. In the SQP procedure, the verification of the sufficient conditions for the solution is automatically (plausibly) implemented if termination is obtained by no variation in the solution (case (i) above).

5.3.2 Microgrid Policies

As previously seen, a microgrid may participate in both energy and ancillary services market through the corresponding MGCC, which will serve as an aggregator of the bids from the DER (including responsive loads, microgenerators and storage devices) located in the LV network.

In [131], Saraiva *et al.* present an approach to schedule microgeneration and validate the dispatch from a technical point of view using a linearized optimization problem. In this paper, the authors propose three possible approaches for economic scheduling: 1) legal enforcement, where it is legally imposed that all power from microsources must be accepted by the distribution system and remunerated according to a pre-specified tariff; 2) signal approach, where there is an initial dispatch by the wholesale market operator without microgeneration contribution (validated by the DSO) and afterwards the MGCCs proposes to replace some generation from traditional power stations adjusting the day-ahead dispatch; 3) the MGCC collects MC and LC bids and is considered a market agent that receives information about the market clearing price and dispatched quantities, which is then disaggregated according to a merit order of generation bids.

According to the latter approach, the microgrid operates similarly to a VPP and the MGCC acts as an aggregator that collects bids and offers from the several microgenerators and loads under its control.

Market participation of microgrids exploits the hierarchical control structure inherent to the microgrid concept. In order to determine the possible contribution to the requested service by microgrids, two microgrid market policies may be envisioned [132]:

- **"Good-citizen"** – the microgrid serves only its own consumers, requesting zero reactive power from the grid.
- **"Ideal-citizen"** – the microgrid participates in the market by buying and selling active and reactive power from/to the grid.

Considering the "good-citizen" policy, the MGCC tries to meet the active power demand according to market prices and production costs. High market prices usually mean that there is peak demand at the whole grid. Due to the high prices, it is beneficial for microsources to produce energy in order to minimize the overall cost of microgrid operation. On the other hand, the microgrid tries to maintain zero reactive power demand from the grid, if possible.

The term "good-citizen" is used because:

- The distribution grid is not burdened by the reactive power demand of the microgrid, so that grid voltage control is made easier;
- At the time of the peak demand and high prices, the microgrid relieves possible network congestion by supplying some of its own energy needs.

In this case, MGCC is provided with:

- The market prices for active power and reactive power;
- The active and reactive power demand, as a result of a short-term load forecasting tool;
- The bids of the microgenerators.

This means that, according to this policy, the microgrid is able to behave like a controllable load.

The "ideal-citizen" policy assumes that the microgrid serves its own needs, but it is also able to participate in the market by presenting bids through an aggregator. The MGCC tries to maximize the value of the microgrid by maximizing the gains from the power exchange with the grid.

In this case, the MGCC is provided with:

- The active and reactive power demand, from a short-term load forecasting tool;
- The bids of each microsource regarding active and reactive power;
- The maximum capacity allowed to be exchanged with the main distribution system (for example through some contractual agreement with the aggregator or due to physical limits of the interconnection line to the grid).

In turn, the MGCC provides:

- Set-points to the microsources;
- Active and reactive power bought from the grid;
- Active and reactive power sold to the grid.

Consequently, the ideal-citizen policy fully enables the provision of ancillary services to the main distribution system.

Additional details on the market policies for microgrids can be found in [133].

A different approach to the participation of a microgrid in the energy market is developed by Celli *et al.* in [134], where an energy management system based on a ANN is able to autonomously make decisions and determine hour by hour the correct dispatch of generators with the final goal of minimizing the global energy costs.

In [135] and [136], the authors aim at evaluating the feasibility and profitability of ancillary services provision from multiple microgrids, in particular regarding primary frequency regulation reserves. Two control approaches are proposed: the coordinated approach, which requires advanced communication infrastructure and the uncoordinated approach, which is simpler to implement.

As seen in Chapter 3, all MGCCs are able to communicate with the CAMC in charge of the MV distribution network and submit the bids for participating in the energy market as well as in the ancillary services markets.

5.3.3 Scenario Definition and var Demand

The ancillary services market proposal for voltage control presented in this chapter is designed to allow the SO to exploit all resources available for voltage support in an economic way, while maintaining safety of operation in the distribution system. In fact, adequate reactive power support and voltage control services are required by the system to enable safe transactions of active power.

Moreover, it is the role of the SO to assess the var needs for operating the system in a secure and reliable way. Consequently, every operation period following the scheduling of generation, which defines the scheduling of all generating units for the day-ahead, an ancillary services market for voltage control is performed. In order to define the scenarios for the 24-hours of the following day, the DSO must also know the expected load profile as well as the foreseen contribution from RES, namely those based on wind and solar irradiation. Therefore, forecasts for both load and for RES using a short-term forecasting tool are assumed to be available.

Furthermore, the islanding of a part of the distribution network can occur due to pre-planned events or to a fault in the upstream distribution system. In this context, a contingency that has to be addressed is related to the occurrence of an islanding of part of the MV distribution network.

As seen in Chapter 3, an MV distribution network comprising multiple microgrids and DG units (multi-microgrid system) can be operated in two different modes:

- **Normal operation** – the MV multi-microgrid system is operated interconnected to the main HV distribution system.
- **Emergency operation** – the MV multi-microgrid system is islanded from the main power system.

Under normal operating conditions, generators as one of the main var providers are not normally operated at their maximum capacity. Furthermore, there will be the need for a margin of reactive reserve to be ensured by all generators and other reactive power compensation devices. These reactive reserves are maintained primarily to provide additional reactive power in the event of an event such as the islanding of a part of the network, which may increase reactive power needs. This sudden increase can be supplied from reactive reserves. Therefore, the SO must ensure that sufficient reactive reserve is available for such situations. In addition, due to localized requirement of reactive power support, these reserves should be appropriately distributed across the network. This var capacity should be exploited for voltage control purposes and var capacity, as well as the use of this capacity, may be remunerated through a market mechanism.

In emergency mode, a pre-specified amount of mandatory var capacity must be defined for all market participants. This capacity may be remunerated through regulated price; however, the use of the var is non-remunerated. These options aim at reducing the risk of blackout especially since in emergency mode there will be no time for running ancillary services markets.

5.3.4 Development of the Tool

As previously explained, a market simulator for ancillary services addressing voltage control has been developed in the MATLAB© environment using MATLAB© R2009b (version 7.9.0). A general overview of the proposal developed in this thesis is shown in Figure 5-4.

First of all, all var sources participating in the market (var suppliers in Figure 5-4) should be identified and present their bids (var bids in Figure 5-4) to the DSO, which is in charge of the var market settlement.

The DSO is also responsible for establishing the var demand. Consequently, the scenarios for the day-ahead ancillary services market are defined based on load and RES forecasts and on the generation scheduling, as presented in Section 5.3.3. Considering all var bids presented by the market players and the var demand set by the DSO enables the market settlement by running an OPF-like algorithm for the 24-hours of the next day.

The approach proposed here is simpler than the one presented in Chapter 4 especially since no coupling has been considered in consecutive periods.

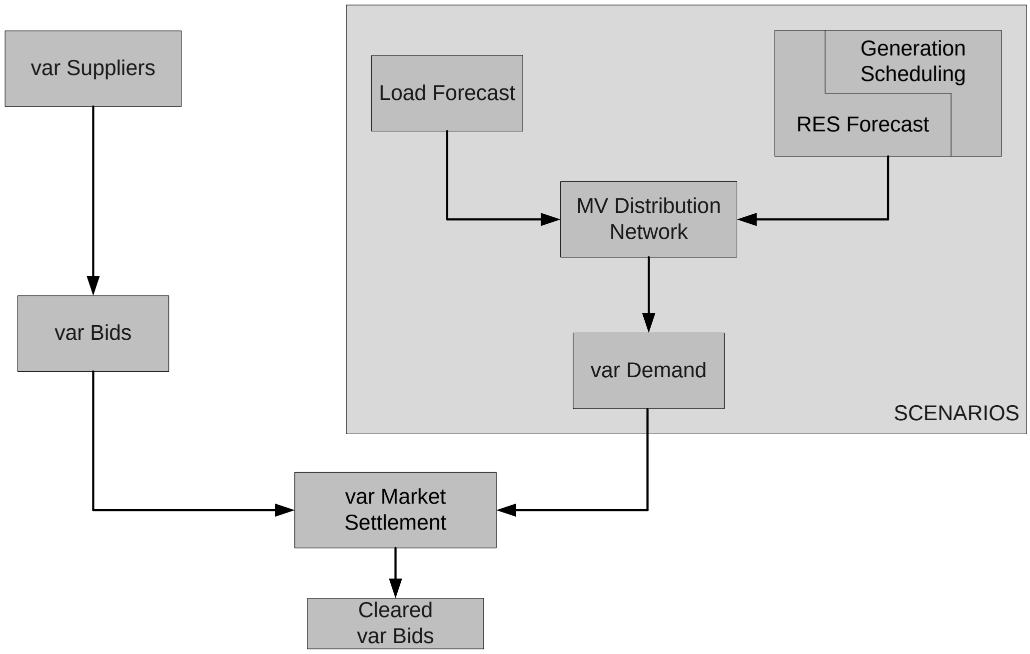

Figure 5-4 – Overview of the var Market Proposal

The OPF-like routine used for performing the market settlement is implemented using the base OPF solver from MATPOWER© (version 3.2) [127], a package of MATLAB© files for solving power flow and OPF problems, with some modifications. MATPOWER© can make use of a number of different OPF solvers. The current generation of solvers uses a generalized AC OPF formulation similar to the one described in Section 5.2. MATPOWER© includes one based on the *fmincon©*[38] function available from the Optimization Toolbox© of MATLAB©. As previously seen, this function utilizes SQP techniques in order to solve non-linear constrained optimization problems.

The OPF formulations in MATPOWER© allow the specification of convex piecewise linear cost functions for active or reactive generator output. An example of this type of cost curves is shown in Figure 5-5. The bids defined by the var suppliers, defined as the blocks shown in Figure 5-3, are converted into corresponding generator capacities and costs.

The result of the market settlement (through the OPF-like routine) is a set of cleared bids for the selected market players and a market price defined as the value of the bid corresponding to the marginal unit. This market price is the uniform price that is due for all market players.

It must be emphasized that the proposal presented here for the ancillary services market for voltage control is designed for interconnected operation only. In the case of emergency operation, under islanded conditions, this approach is not suitable given the stressed operating conditions and the time-frame for the control requirements.

[38] *fmincon©* attempts to find a constrained minimum of a scalar function of several variables starting at an initial estimate. This is generally referred to as constrained non-linear optimization or non-linear programming.

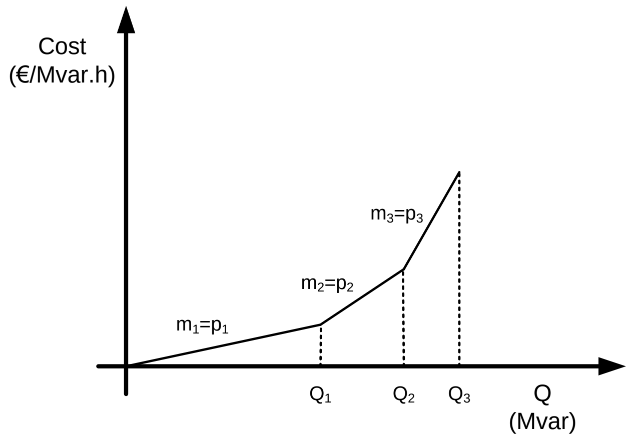

Figure 5-5 – Piece-wise Linear Costs corresponding to the Block Bids

Where

m_i is the slope of line segment i
p_i is the price of block bid i

5.3.5 Integration of the Ancillary Services Market Module

The ancillary services market for voltage control as proposed here is assumed to be a functionality to be included in the CAMC, which is in charge of the multi-microgrid system as seen in Chapter 3. The implementation of this type of market conforms to the vision for future distribution systems namely concerning decentralized planning and operation.

As previously seen, the CAMC (to be installed at the HV/MV substation) is in charge of the MV and LV distribution systems, operating under the responsibility of the DSO. It includes several key functionalities for the management and operation of the distribution system.

Figure 4-15 illustrates the several functionalities for control and management of the distribution system included in software packages housed in the CAMC, including the ancillary services market module presented.

The CAMC identifies all market players, collects the reactive power bids from the several players for the next operating period (one day horizon), together with data on generation scheduling, RES forecasts and load forecasts, in order to be able to compute the reactive power needs for that period. The microgrids are able to bid, based on their local resources, through the corresponding MGCC. The ancillary services market module in the CAMC is then used to run the ancillary services market for voltage control by clearing the var bids in order to satisfy the demand and reach the market settlement. After successfully achieving market settlement, the final closing price is defined (which is used to remunerate all allocated service providers) and market players are informed of the results obtained.

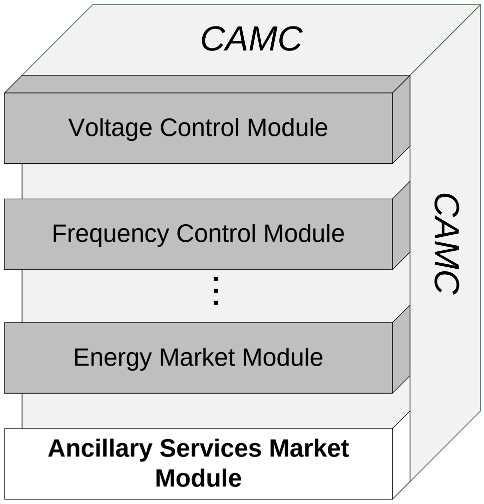

Figure 5-6 – Ancillary Services Market Module included in the CAMC

5.4 Summary and Main Conclusions

The participation of DG in network operation, especially by providing ancillary services, will be one of the key drivers for fostering the integration of DER in electrical distribution systems. In particular, voltage support and reserves are particularly suitable for being provided by this type of units.

The main products associated to the voltage support service identified are the reactive power capacity and its use. A proposal for an ancillary services market for voltage control has been developed based on a daily market for var use. In addition, it is considered that var capacity may also be remunerated through the implementation of a long-term auction, although this is outside the scope of this thesis.

The main providers of the service are DG units, capacitor banks and microgrids. Considering the architecture of multi-microgrid systems presented in Chapter 3, a microgrid can be operated similarly to a VPP, from the MV distribution system point of view. In this case, the MGCC will act as an aggregator that collects the bids from the several DER connected to the LV network and present aggregated offers to the energy and ancillary services market.

Regarding ancillary services provision for voltage control, the requirements for the service (namely var demand) is defined by the DSO in order to ensure secure operation of the distribution system both under normal operation and in emergency situations. In order to define the var demand, forecasts for load and RES, as well as the information from the generation scheduling, for the next day must be considered.

In normal operation, participation in the ancillary services market for voltage control is optional and var capacity use is valued based on the market price, considering a uniform price corresponding to the bid of the marginal unit. In this mode, two policies for microgrid market participation can be envisioned: “good-citizen” and “ideal-citizen”. According to the “ideal-citizen” policy, the microgrid is able to sell ancillary services such as voltage support to the main distribution system.

Under emergency conditions, islanded operating mode may be required and, in this case, there will be no market for ancillary services. The participation in the service will be mandatory and not remunerated in terms of var utilization.

An optimization formulation is used to select efficiently the reactive power bids based on an OPF-like routine. The main objective of this optimization problem is to minimize the costs associated with the purchase of reactive power capacity by the DSO and the constraints are the power flow equations and the operating limits of the equipment. The results from the OPF provide the market settlement and define the cleared var bids and the corresponding market price.

"Knowing is not enough; we must apply. Willing is not enough; we must do."

Johann Wolfgang von Goethe (b. 1749 – d. 1832)

Chapter 6 – Main Results

In this chapter, some of the most relevant results that were obtained from testing the coordinated voltage support tool and the ancillary services market simulator for voltage control are presented. Firstly, the several MV and LV distribution test networks used to create the cases used for the simulations are described. Then, the performance of the ANN architecture used to replace "active" LV networks comprising several microgeneration units in the voltage control algorithm is analysed. Afterwards, results from the voltage support tool, developed in Chapter 4, concerning one-hour and 24-hour periods are presented for evaluating the performance of the algorithm. Finally, for the ancillary services market simulator, two scenarios are detailed considering the two microgrid policies presented in Chapter 5.

6.1 Test Networks

Two MV test networks and three LV test networks have been identified and used for testing purposes in order to assess the performance of the coordinated voltage support tool and the ancillary services market simulator for voltage control.

6.1.1 Medium Voltage Networks

As previously mentioned, two different MV networks were employed in this work. A large dimension MV grid was used for testing the behaviour of the voltage support tool that was developed and a smaller MV test system was used for testing the methodology proposed for the ancillary services market simulator for voltage control.

Both of these networks include MV-connected DG units and microgrids. In this approach, from the MV point of view, each microgrid was considered as a single bus with an equivalent generator (corresponding to the sum of all microsource generation) and equivalent load (corresponding to the sum of all LV loads).

The MV networks used here are summarily described in the following sections. A detailed description of the data concerning these two networks (including line, transformer, load data and generation data) is given in Appendix B.

6.1.1.1 Medium Voltage Network 1

The first MV network employed in this work is based on a real Portuguese MV distribution network and it was used for testing the coordinated voltage support tool developed. The one-line diagram of the network is presented in Figure 6-1. All data concerning this network was provided by Energias de Portugal (EDP), the Portuguese utility, specifically for the More MicroGrids project.

It is a typical rural network with a radial structure that includes two distinct areas with different voltage levels: 30 kV at starting at the transformer shown at the top of Figure 6-1 and 15 kV after the OLTC transformer located in the middle of Figure 6-1. This network has a total of 211 nodes and 212 branches. The OLTC transformer is a 30 kV/15 kV transformer with taps on the secondary side of the transformer.

DG units and "active" LV networks (microgrids) were added to this network in order to assess the performance of the voltage support tool in managing the MV distribution system with several different generating units and to evaluate the impact of these units on network operation. Consequently, six microgrids (labelled as Microgrid 1, Microgrid 2, Microgrid 3, Microgrid 4, Microgrid 5, and Microgrid 6 in Figure 6-1) and three DG units (two wind generators based on DFIGs – labelled as DFIG 1 and DFIG 2 – and a CHP unit – labelled as CHP in Figure 6-1) were included.

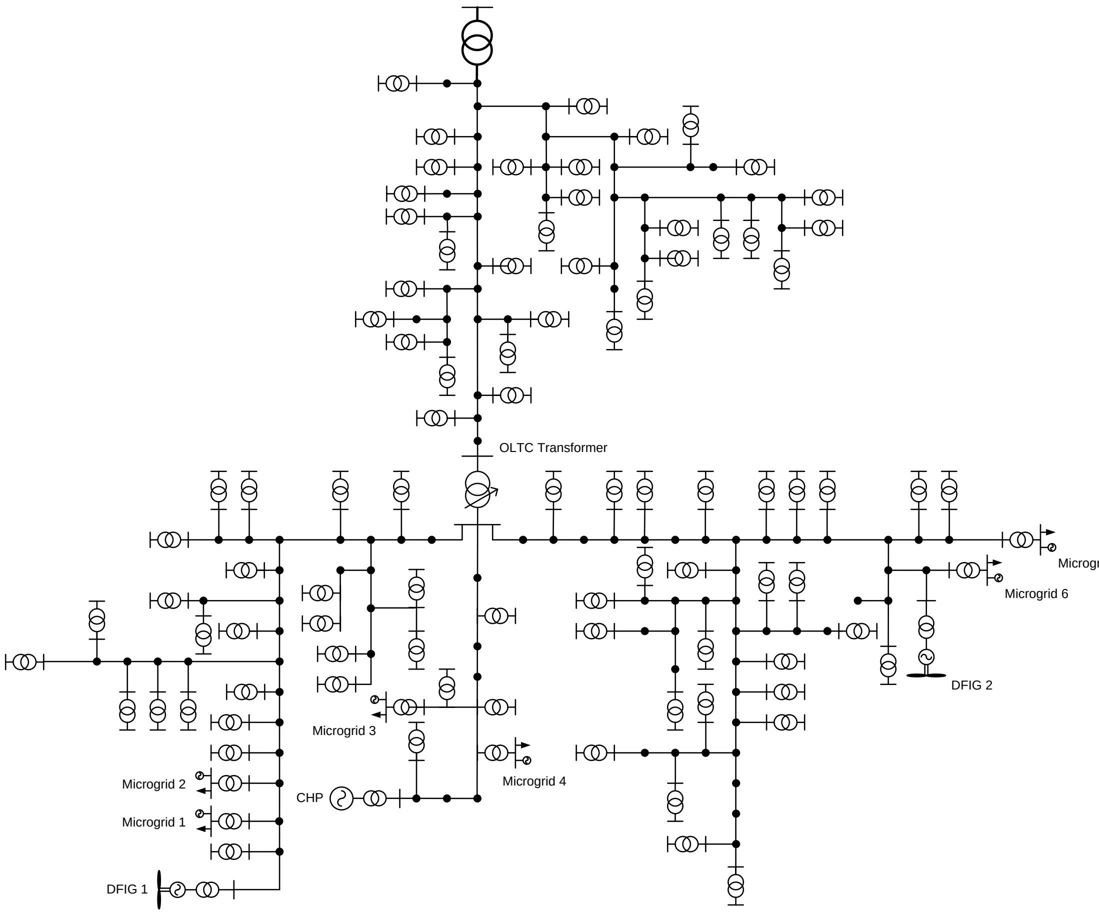

Figure 6-1 – MV Network 1

6.1.1.2 Medium Voltage Network 2

A study-case test network developed purposely for the More MicroGrids project has also been used in this thesis. This network is a test system that uses real data and has been developed by INESC Porto, following a previous version designed by the National Technical University of Athens [137]. More details on the several versions of this network can be found in [126]. It was designed for testing both the dynamic and steady-state behaviour of an MV distribution network comprising several DG units and microgrids, within the framework of the More MicroGrids project.

This test network is shown in Figure 6-2 and contains several DG sources directly connected to the MV level namely a Diesel generator, a DFIG-based wind farm, a Hydro unit based on an induction generator and a CHP unit using a synchronous generator. Several LV networks are connected to the main MV network including five "active" networks – microgrids.

This network has two distinct areas: one with a typical urban topology (*i.e.* loop, using a ring structure in order to ensure some reconfiguration capability in case of an event such as a short-circuit in an MV line, shown on the left-hand side of Figure 6-2) and another with a rural topology (typically radial in structure, shown on the right-hand side of Figure 6-2). This network has a total of 55 nodes and 55 branches, although the network is operated radially in normal operating mode.

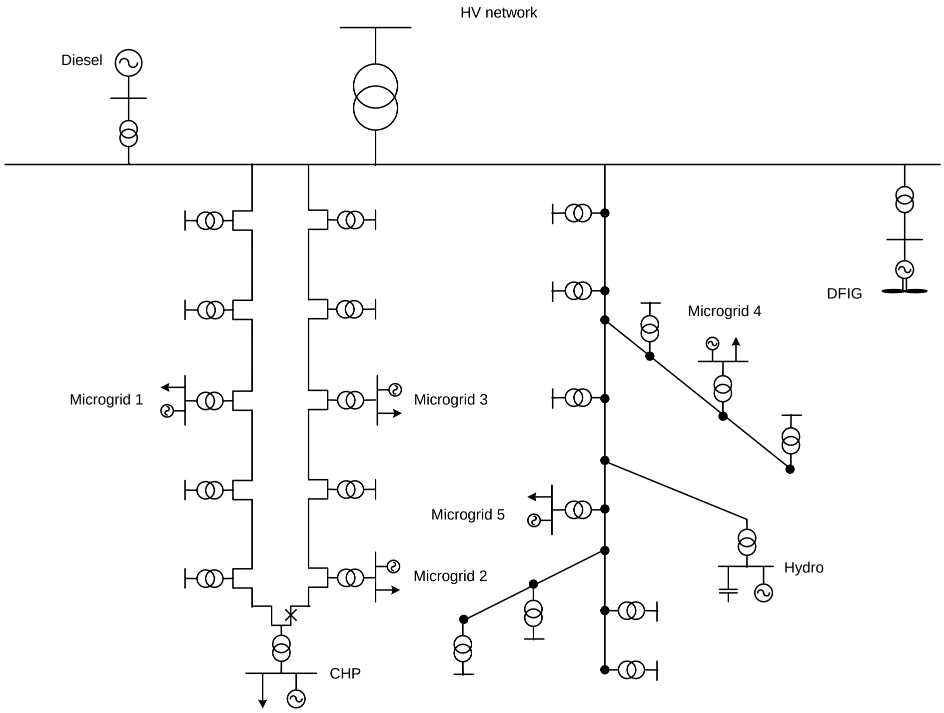

Figure 6-2 – MV Network 2

6.1.2 Low Voltage Networks

In addition, three different LV distribution networks were employed in order to test the coordinated voltage support tool that was developed. These networks are real Portuguese LV networks, considered as typical networks for rural or semi-urban areas. Once again, all the data concerning these networks was provided by EDP.

In order to turn these "passive" networks into microgrids, microgeneration units were added. Therefore, future scenarios for microgeneration integration in LV networks have been developed based on the current regulation for microgeneration in Portugal[39] [138]. Therefore, microgeneration was added to all customer nodes that have an installed capacity of at least 6,9 kVA (it was assumed that smaller installed capacities are not likely to have microgeneration units although this is not restricted by regulation) and comply with the following rules:

[39] As of the 2nd November 2007, according to the Portuguese Decree-Law nº 363/2007 from the Ministry of Economy and Innovation.

- The amount of microgeneration capacity installed does not exceed 50% of the contracted installed capacity for any customer;
- The total amount of microgeneration capacity installed does not exceed 5,75 kVA for each customer.

The Portuguese regulation also limits the total capacity installed of microgeneration to 25% of the rated power of the MV/LV distribution transformer. However, this limitation was not included since it was considered much too restrictive having in mind future scenarios for microgeneration penetration. In addition, and again considering the Portuguese case, the technologies most likely to be installed at the LV level are those based on RES such as solar (mostly PV) and wind. Consequently, it was considered that all microgeneration units included should be based on PV panels. Regarding reactive power, it was assumed that all microgeneration units being based on PV technology should supply power considering a unitary power factor, *i.e.* no reactive power is generated.

As previously mentioned, each of these LV networks is replaced by an ANN equivalent in the voltage control algorithm developed in Chapter 4. Consequently, three ANN models were derived and have been incorporated in the voltage support tool. The three LV networks used in this work are briefly described in the following sections. They have been chosen given their different characteristics in terms of number and length of feeders, number of microgeneration units and total amount of microgeneration installed capacity. It was considered that this could reflect in a more realistic way the diversity of LV networks that can be found in Portugal. The complete data concerning these networks is presented in Appendix B.

6.1.2.1 Low Voltage Network 1

The first LV distribution network used is a typical radial network with three main feeders and a total of 33 nodes and 32 branches. It has a distribution transformer of 100 kVA. A one-line diagram of this network is shown in Figure 6-3.

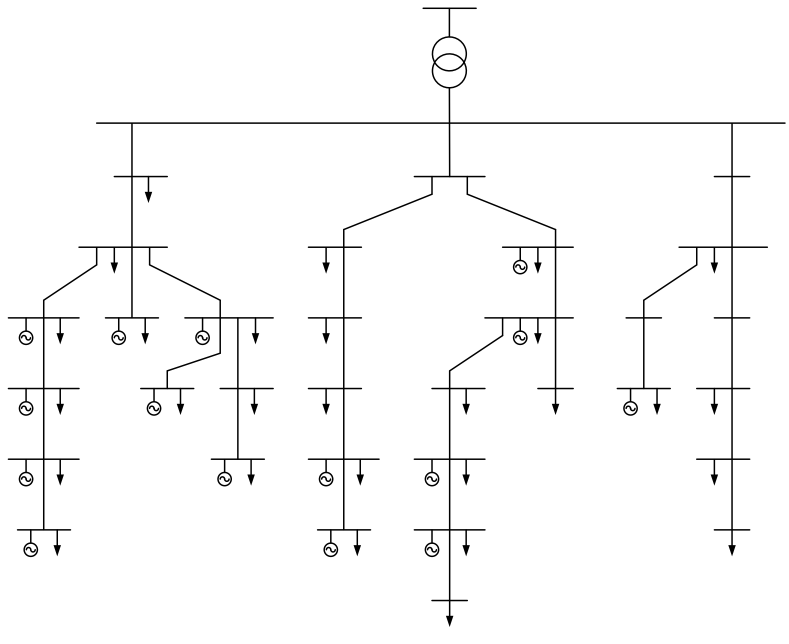

Figure 6-3 – LV Network 1

Since this network is an LV network, most loads and microgeneration units are single-phase, especially those with lower power ratings. As previously stated, all microgeneration units included are based on PV technology.

6.1.2.2 Low Voltage Network 2

The second LV distribution network used is also a typical radial network with five main feeders and a total of 37 nodes and 36 branches. It has a distribution transformer of 630 kVA. A one-line diagram of this network is shown in Figure 6-4.

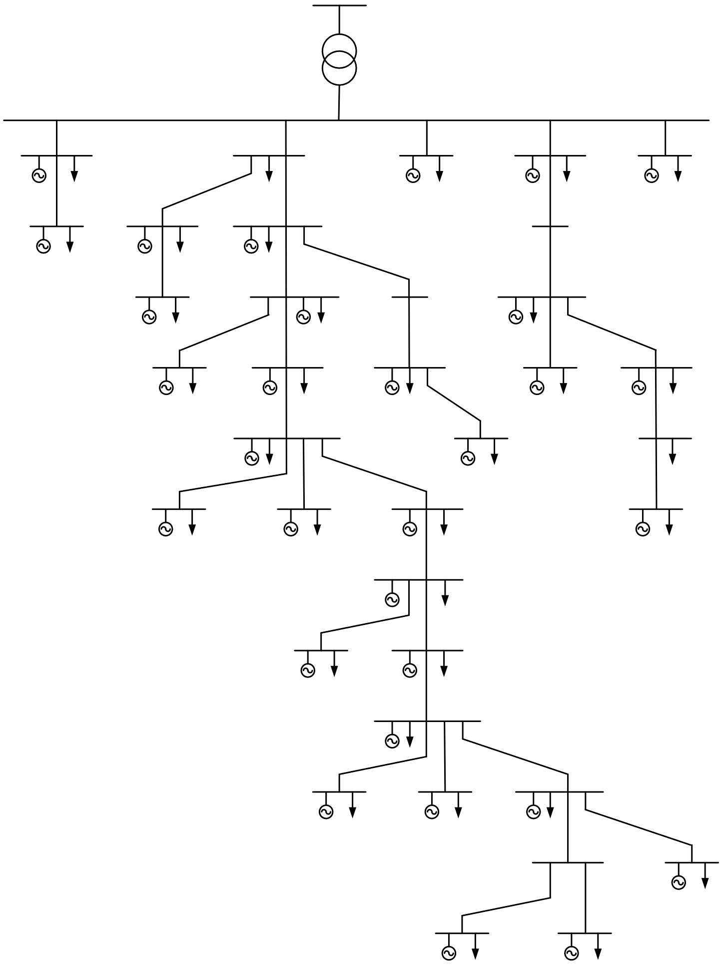

Figure 6-4 – LV Network 2

6.1.2.3 Low Voltage Network 3

The third and final LV distribution network used is again a typical radial network with three main feeders and a total of 70 nodes and 69 branches. It has a distribution transformer of 100 kVA, similarly to the first network. In this case, there are only a few microgenerators since most customers are small single-phase loads with small installed capacity, typically 1,15 kVA and 3,45 kVA. A one-line diagram of this network is shown in Figure 6-5.

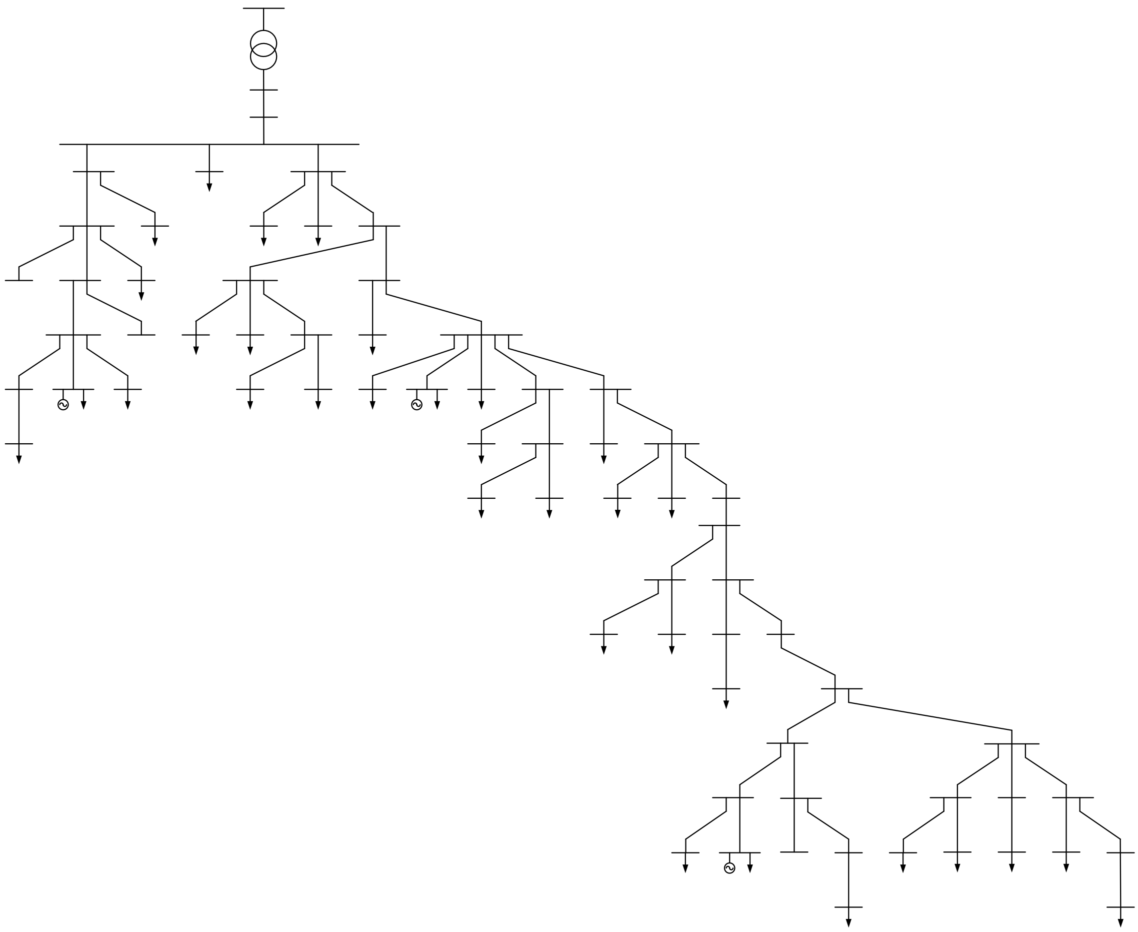

Figure 6-5 – LV Network 3

6.2 Low Voltage Network Model

As previously seen in Chapter 4, an ANN model was designed for reproducing the behaviour of each "active" LV network to be used in the voltage control algorithm developed (*i.e.* microgrid). This strategy allows relieving the computational burden of the voltage support tool and speed-up the algorithm that is intended to be used in a real-time management environment.

The inputs required for the ANN are:

- Voltage set-point at the MV/LV transformer;
- Total active power generation in phase 1;
- Total active power generation in phase 2;
- Total active power generation in phase 3;
- Total active power load in phase 1;
- Total active power load in phase 2;
- Total active power load in phase 3.

The targets for the ANN are:

- Total active power losses in phase 1;
- Total active power losses in phase 2;

- Total active power losses in phase 3;
- Maximum voltage value in phase 1;
- Maximum voltage value in phase 2;
- Maximum voltage value in phase 3.

In order to adequately evaluate the behaviour of an LV network in steady-state conditions, a three-phase power flow routine was used. The algorithm for the three-phase power flow, which was presented in Chapter 4 and is detailed in Appendix A, was used to generate the data set for training the ANN. Therefore, in order to generate the data set corresponding to the inputs chosen to train the ANN, a large number of power flows were computed, considering different combinations of the inputs (*i.e.* several values for the voltage reference at the MV/LV substation, for the total active power generated in phase 1, *etc.*) in order to calculate the active power losses and assess the voltage profiles (targets) in each scenario, according to the methodology described in Section 4.3.3.3.

6.2.1 Artificial Neural Network Performance

In the following sections, the performance of the ANNs developed for replacing each of the LV networks presented in Section 6.1.2 is assessed. In particular, the quality of the results obtained is discussed and analysed and, in face of this, the results are validated.

6.2.1.1 Artificial Neural Network 1

The standard way used for evaluating the performance of an ANN is through the MSE. Figure 6-6 shows the evolution of the MSE for 500 epochs for the train, validation and test sets developed for the ANN using the data from the LV Network 1 presented in Section 6.1.2.1.

As can be observed, the MSE corresponding to the best validation performance is rather small (approximately 3,9 x 10^{-6} at epoch 500) and the performance is quite similar for the train, validation and test sets.

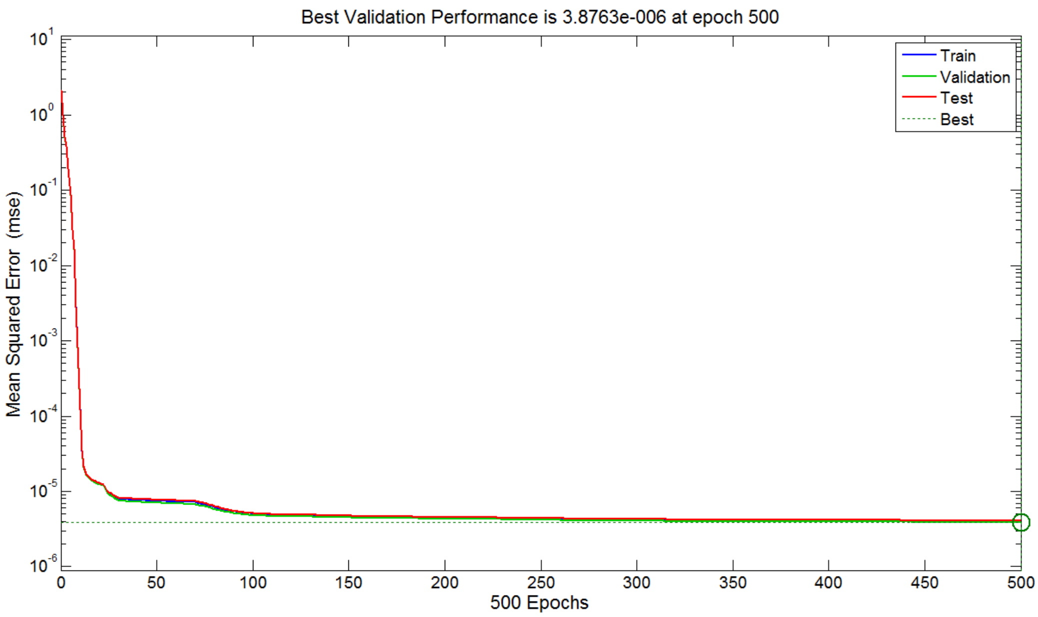

Figure 6-6 – MSE for Train, Validation and Test Sets following Training of ANN 1

Furthermore, in order to evaluate the quality of the outputs provided by the ANN, linear regressions of the outputs of the ANN relative to the target values were performed. The linear regressions concerning the complete data set used are shown in Figure 6-7.

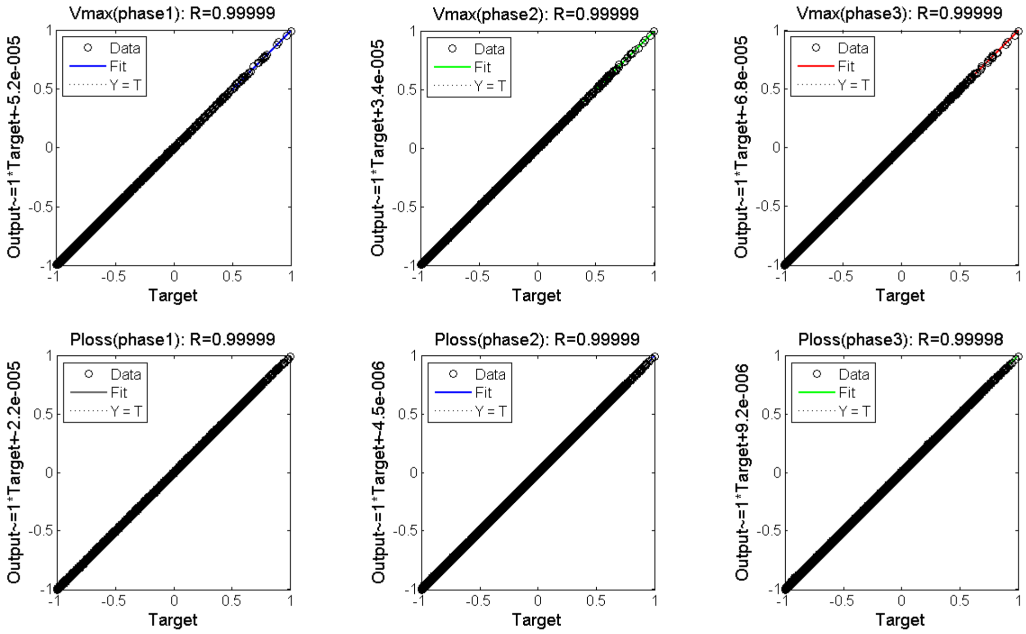

Figure 6-7 – Linear Regression of Targets relative to Outputs of ANN 1

As can be observed, the linear regressions obtained for each of the outputs illustrate the high quality of the results provided by this ANN design. Furthermore, the operating points that were generated seem to have enough diversity, which is essential in order to try to cover the most out of the solution space.

In conclusion, the ANN model that was developed should be able to reproduce accurately the three-phase power flow computation for this particular LV network.

6.2.1.2 Artificial Neural Network 2

Figure 6-8 shows the evolution of the MSE for 500 epochs for the train, validation and test sets developed for the ANN model designed to replace the LV Network 2 presented in Section 0 in the voltage control algorithm.

As can be seen, the MSE obtained corresponding to the best validation performance is, once more, rather small (approximately 2,0 x 10^{-6} at epoch 500) and the behaviour is again quite similar for the train, validation and test sets.

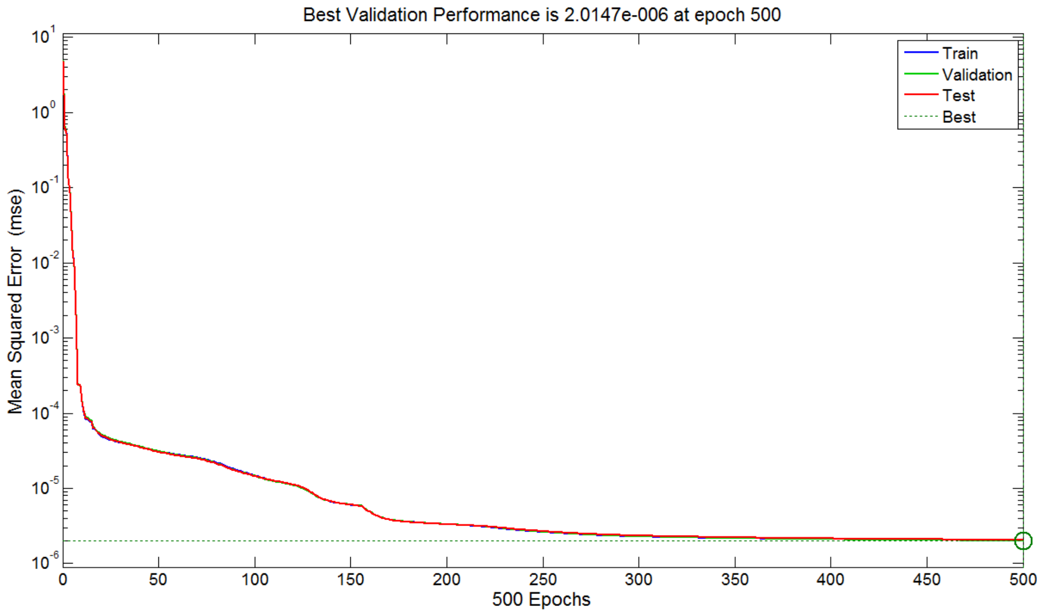

Figure 6-8 – MSE for Train, Validation and Test Sets following Training of ANN 2

Moreover, linear regressions of the outputs of the ANN relative to the target values were computed. The linear regressions obtained using the complete data set for the ANN model are presented in Figure 6-9.

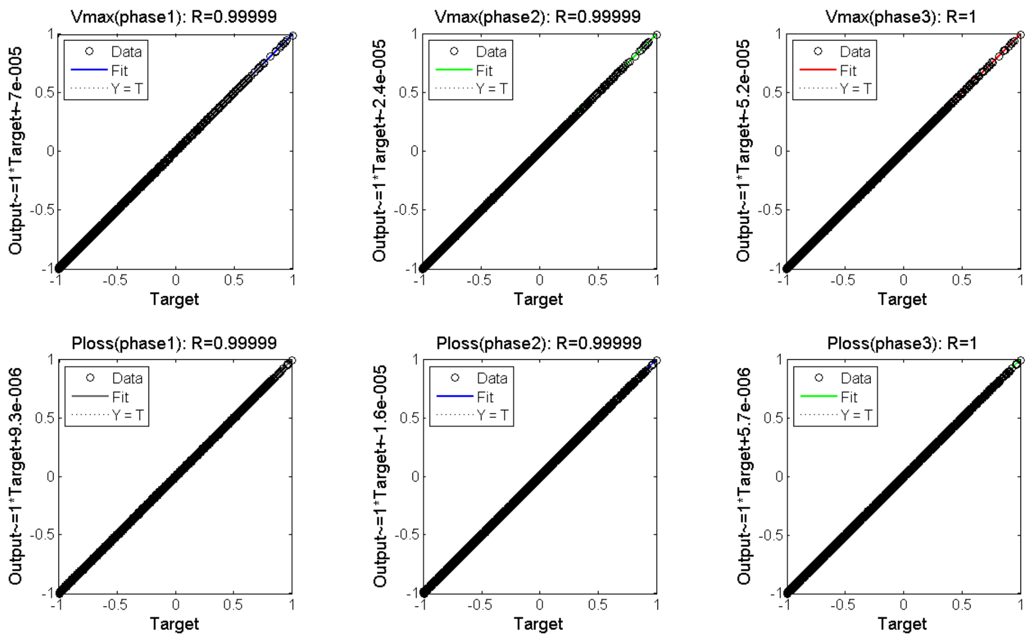

Figure 6-9 – Linear Regression of Targets relative to Outputs of ANN 2

As can be observed, the linear regressions obtained for all six outputs illustrate the high quality of the results provided by the ANN model.

6.2.1.3 Artificial Neural Network 3

Figure 6-10 shows the evolution of the MSE for 500 epochs for the train, validation and test sets generated for the ANN model to replace the LV Network 3 (presented in Section 6.1.2.3) in the voltage control algorithm developed.

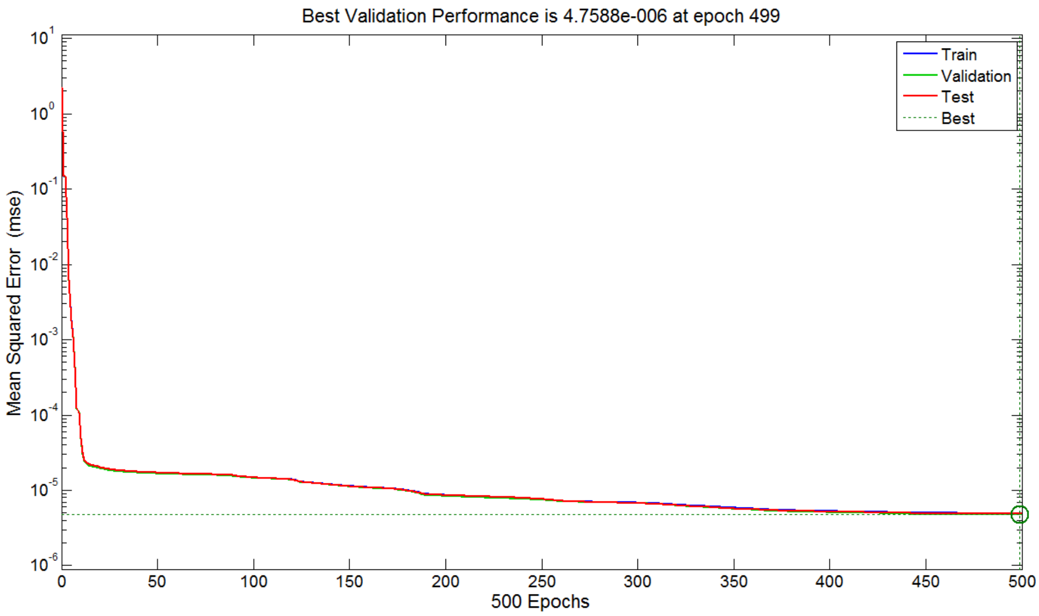

Figure 6-10 – MSE for Train, Validation and Test Sets following Training of ANN 3

As can be seen, the MSE corresponding to the best validation performance is once again small (approximately 4,8 x 10^{-6} at epoch 499) and the performance is similar for the train, validation and test sets.

Moreover, linear regressions of the outputs of the ANN relative to the target values were calculated. The linear regressions obtained for the complete data set are shown in Figure 6-11.

From the linear regressions obtained it can be concluded that the results provided for all six outputs of the ANN have superior quality.

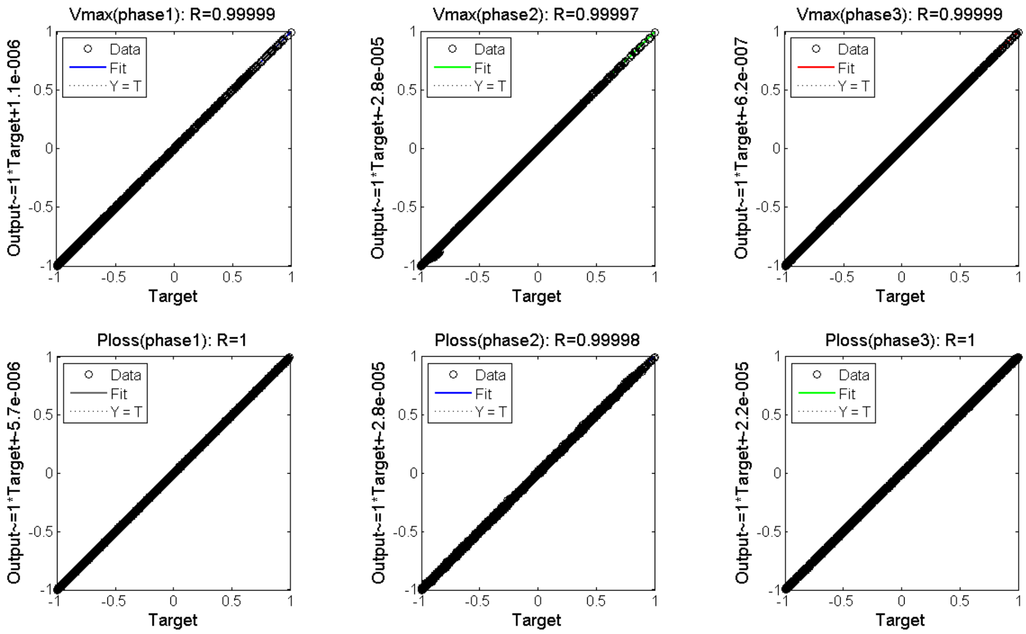

Figure 6-11 – Linear Regression of Targets relative to Outputs of ANN 3

6.3 Coordinated Voltage Support

In this section, the performance of the algorithm developed for the voltage support tool (as presented in Chapter 4) is analysed and some of the results obtained are presented and discussed.

6.3.1 Initial Considerations

Several simulations have been performed using a test case based on an MV Distribution network comprising several MV-connected DG units and microgrids that was specifically developed for this thesis. For this case, the MV network presented in Section 6.1.1.1 was used. In addition, three ANNs have been developed for replacing the three LV networks presented in Section 6.1.2. It was considered that Microgrid 1 and Microgrid 2 shown in Figure 6-1 are replaced by the ANN 1 model presented in Section 6.2.1.1, Microgrid 3 and Microgrid 4 shown in Figure 6-1 are replaced by the ANN 2 model presented in Section 6.2.1.2 and Microgrid 5 and Microgrid 6 shown in Figure 6-1 are replaced by the ANN 3 model presented in Section 6.2.1.3.

According to the method that was developed in Chapter 4, the main objective of this optimization algorithm is to minimize active power losses and microgeneration shedding. As the microgeneration shedding option only makes sense in case the voltage values are above admissible limits, a flag variable[40] was added that only allows microgeneration shedding in case of overvoltages in the LV side. It was found that this also allows narrowing down the space of possible solution, thus speeding-up the convergence of the algorithm.

This procedure is especially important since the preliminary tests that have been performed using the algorithm suggested the existence of multiple local minima.

Furthermore, as previously seen, the possible control actions that have been identified are: shedding of microgeneration units, reactive power supplied/absorbed from/by the MV-connected DG units and tap settings of OLTC transformers.

Therefore, for the test system used here, the control variables considered are:

$P_{\mu G1}$	$P_{\mu G2}$	$P_{\mu G3}$	$P_{\mu G4}$	$P_{\mu G5}$	$P_{\mu G6}$	Q_{CHP}	Q_{DFIG1}	Q_{DFIG2}	t_{OLTC}

Where

$P_{\mu Gi}$ is the total active power generation shedding in microgrid i
Q_{CHP} is the reactive power generated by the CHP unit
Q_{DFIG1} is the reactive power generated by DFIG 1unit
Q_{DFIG2} is the reactive power generated by DFIG 2 unit
t_{OLTC} is the tap value in the OLTC transformer

[40] A flag variable in computer programming is a variable that is defined to have one value until some condition changes (from true to false or *vice versa*), in which case the value of the variable is changed.

Several preliminary tests were made to the optimization algorithm employed (EPSO) in order to identify the most suitable parameters for the simulation case at hand. The selection of these parameters was done using a "trial-and-error" approach.

According to the formulation presented in Chapter 4, the parameters to be used in the EPSO algorithm have been identified are presented in Table 6-1.

Table 6-1 – EPSO Parameters

Parameter	Value
Number of Particles	20
Number of Replicates	1
Number of Generations	1000
Learning Parameter $\boldsymbol{\tau}$	0,5

Furthermore, as discussed in Chapter 4, penalty functions were employed for modelling the inequality constraints, using the general formulation presented below.

$$\begin{cases} 0, & \forall x: x_{min} \leq x \leq x_{max} \\ k \cdot (x - x_{max})^{n_x}, & \forall x: x > x_{max} \\ k \cdot (x_{min} - x)^{n_x}, & \forall x: x < x_{min} \end{cases}$$ **Equation 6-1**

Where

x is a control or state variable
k is a constant value
n_x is the exponent
x_{min} is the minimum admissible values for variable x
x_{max} is the maximum admissible values for variable x

Therefore, the following penalty functions have been used:

Table 6-2 – Penalty Functions

$\boldsymbol{x_{min}}$	$\boldsymbol{x}$	$\boldsymbol{x_{max}}$	$\boldsymbol{k}$	$\boldsymbol{n_x}$
0,95	V_i	1,05	1x10^6	2
–	S_{ik}	S_{ik}^{max}	1x10^6	2
$\boldsymbol{-0,2 \cdot P_{CHP}^{G}}$	Q_{CHP}^{G}	$0,4 \cdot P_{CHP}^{G}$	1x10^6	2
$\boldsymbol{-0,1 \cdot P_{DFIGi}^{G}}$	Q_{DFIGi}^{G}	$0,2 \cdot P_{DFIGi}^{G}$	1x10^6	2
0,9	t	1,1	1x10^6	2
–	$\lvert t^k - t^{k-1} \rvert$	0,01	1x10^6	1

Where

V_i is the voltage at bus i
S_{ik} is the apparent power flow in branch ik

S_{ik}^{max}	is the maximum apparent power flows in branch ik
Q_{CHP}^{G}	is the reactive power generation of the CHP unit
P_{CHP}^{G}	is the active power generation of the CHP unit
Q_{DFIGi}^{G}	is the reactive power generation of DFIG unit i
P_{DFIGi}^{G}	is the active power generation of DFIG unit i
Q_i^{min}, Q_i^{max}	are the minimum and maximum reactive power generation at bus i
t	is the transformer tap of OLTC transformer
t^k, t^{k-1}	are the tap settings for OLTC transformer at period k and $k-1$, respectively

The current computational time required for running the algorithm is around 45 minutes using a personal computer equipped with a Duo Core CPU at 3,16 GHz and with 4 GB of RAM memory. The heavy computational burden has mostly to do with the time required for calculating consecutive MV power flows, given that a reasonably large-dimension network was used. Nevertheless, the inclusion of the ANNs to replace the “active” LV networks has already allowed a significant reduction of simulation times, since prior to the use of the ANNs the total simulation time was around three times larger than in the present version of the algorithm.

Although it is recognized that the current computational time is still fairly high, it must be stressed that, during this thesis, there was not excessive concern in optimizing the computer code for the voltage support tool. It was considered that the main objective of this work was to propose both a methodology and a formulation that could deal with the voltage control problem in distribution systems with large DG and microgeneration penetration rather than developing a final software product that could be directly incorporated in a commercial tool. Naturally, this would require additional effort both on revising the code, as well as on the development of the interface and specification of all inputs and outputs required. It is strongly believed that total simulation time can be significantly reduced once the computer code is improved and optimized. The improvement of the code is vital in order to develop an efficient tool that can be directly integrated in the control software made available to the DSO, as suggested in Chapter 4.

6.3.2 Multi-Objective Decision Aid Analysis

According to the formulation presented in Chapter 4, the objective of the voltage support algorithm developed is to simultaneously minimize active power losses and microgeneration shedding subject to a set of technical and operational constraints.

In order to address this multi-objective problem a decision parameter α is introduced, as explained in Section 4.2.4. It is expected that the decision-maker, which in this case should be the DSO, defines this value according to its preferences. Consequently, in order to assess the influence of this decision parameter in the performance of the algorithm, several preliminary tests have been performed. Therefore, a detailed analysis was carried out by running the algorithm for one same operation scenario and considering several values for α in the interval [0; 1]. In total, twenty-one points were considered for α by taking steps of 0,05.

In this case, an extreme scenario with high DG and microgeneration penetration was considered where “active” LV networks are injecting power into the MV network. All the data from the test case presented here can be found in Appendix B. The operation scenario considered is summarized in Table 6-3.

Table 6-3 – Scenario for Load and Generation

Network	Total Load [MW]	Total Generation [MW]
MV Network	2,677	3,702
Microgrid 1	0,046	0,058
Microgrid 2	0,046	0,058
Microgrid 3	0,227	0,304
Microgrid 4	0,227	0,304
Microgrid 5	0,019	0,012
Microgrid 6	0,019	0,012

Furthermore, and since there were previous indications from experience in testing the voltage control algorithm that the problem exhibits multiple local optima, each simulation had as a starting point the best solution from the previous run.

Figure 6-12 plots the two objectives (active power loss minimization and microgeneration shedding minimization) for the several values of α considered.

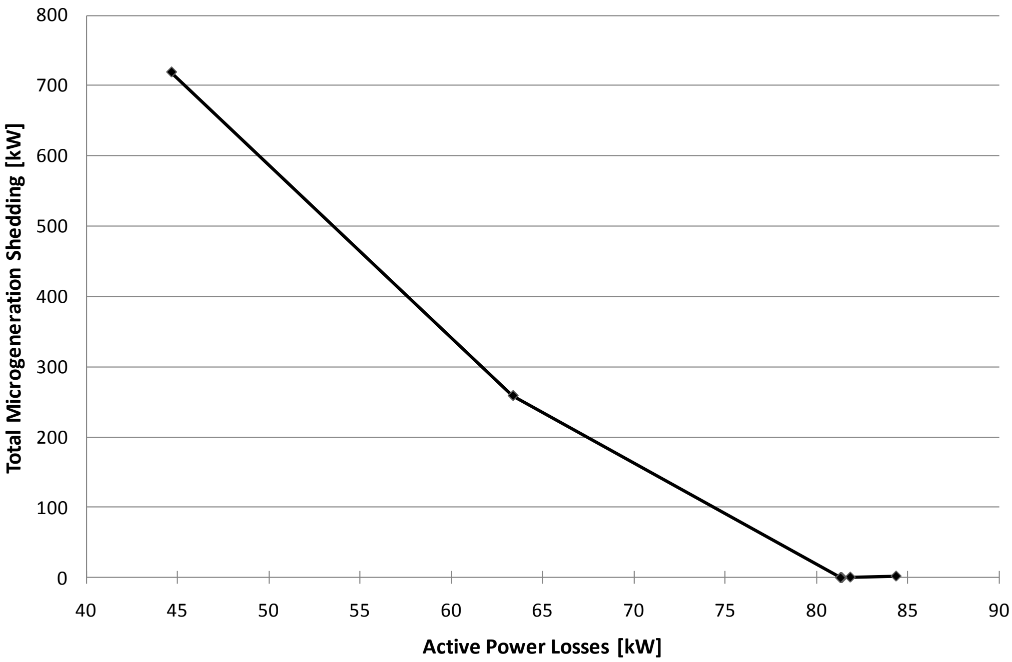

Figure 6-12 – Microgeneration Shedding *vs.* Active Power Losses

This figure shows that most of the points obtained are concentrated in one zone around the point [0,08; 0]. It will be seen that this group of points corresponds to intermediate values of α, while the remaining points that are isolated from this group are extreme values for α (near 0 and 1).

Figure 6-13 and Figure 6-14 detail this behaviour by plotting the values of active power losses and microgeneration shedding as functions of the decision parameter α.

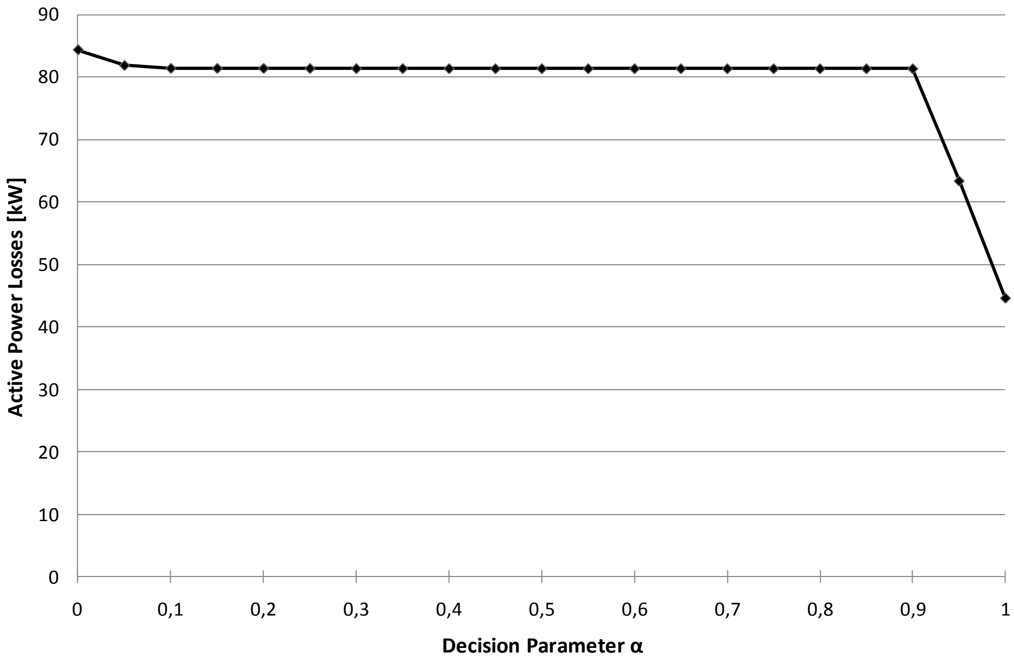

Figure 6-13 – Active Power Losses as a Function of the Decision Parameter α

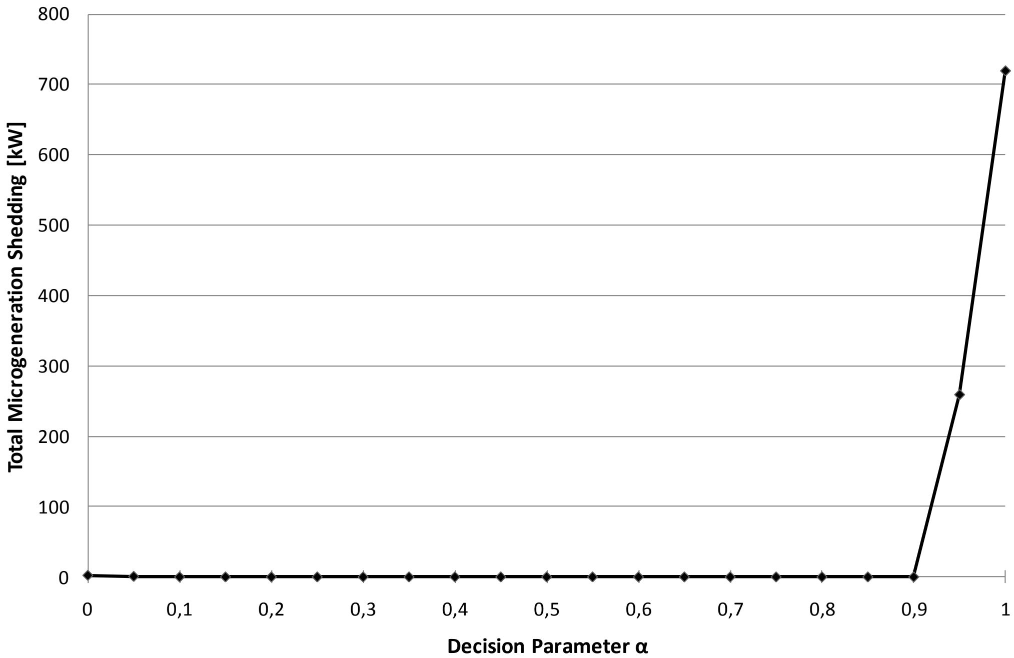

Figure 6-14 – Microgeneration Shedding as a Function of the Decision Parameter α

Here, the three above mentioned groups of points are clearly shown: small values of α, corresponding to a situation where active power losses are almost neglected; intermediate values of α where both objectives are weighed; and high values of α where active power losses are strongly valued.

This analysis emphasizes that extreme values for the decision parameter α should not be selected as the impact on the optimization algorithm is more severe. Furthermore, selecting intermediate values for α leads to very similar partial objective values so that the choice of any particular value in this range does not affect the final result significantly. Consequently, in the simulation runs presented in the following sections, an intermediate value of $\alpha = 0{,}5$ will be used.

6.3.3 Performance of the Algorithm

In the next sections, the performance of the optimization algorithm developed for the voltage support tool is analysed for a one-hour period and for a twenty-four hours horizon (based on hourly runs of the algorithm for one whole day).

6.3.3.1 Results from One Operating Period

In order to assess the performance of the optimization algorithm used in the voltage support tool, several runs of the algorithm were performed to track the evolution of the best solution, *i.e.* to evaluate the convergence of the algorithm for one operating period of one-hour.

As previously mentioned, in the simulations presented, the value considered for the decision parameter α included in the objective function was 0,5. The scenario used here is the one that was presented in Section 6.3.2 and the algorithm was run for a total of 1000 iterations.

Firstly, five independent runs of the algorithm were performed starting from a set of randomly generated solutions. This procedure allows analysing the behaviour of the meta-heuristic tool used in converging to the best solution. Figure 6-15 shows the evolution of the value of the objective function (*i.e.* fitness) for the best solution obtained at each of the 1000 iterations run.

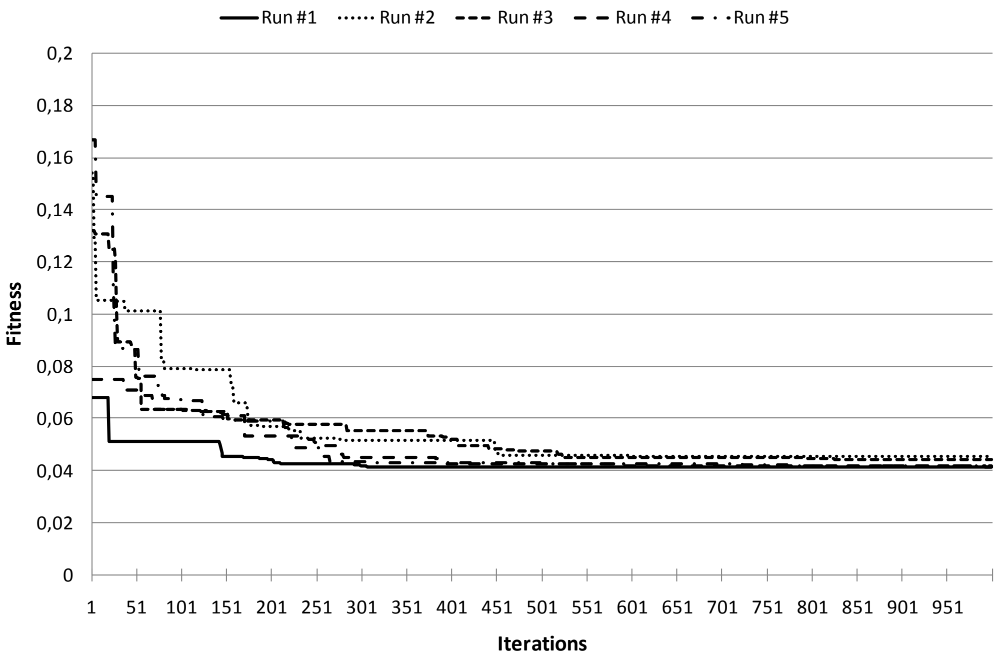

Figure 6-15 – Evolution of the Fitness Function for Five Independent Runs

It can be observed that all runs exhibit a similar pattern and convergence is fairly quick, with more noticeable improvements in the first hundred iterations followed by slower convergence during the last iterations. After 500 iterations, the algorithm has practically stabilized and no significant improvement is achieved for most runs.

One typical run of the voltage control algorithm out of the five runs that were performed will be analysed in detail in order to further evaluate the performance of the algorithm. Figure 6-16 isolates the value of the objective function for one typical run of the algorithm.

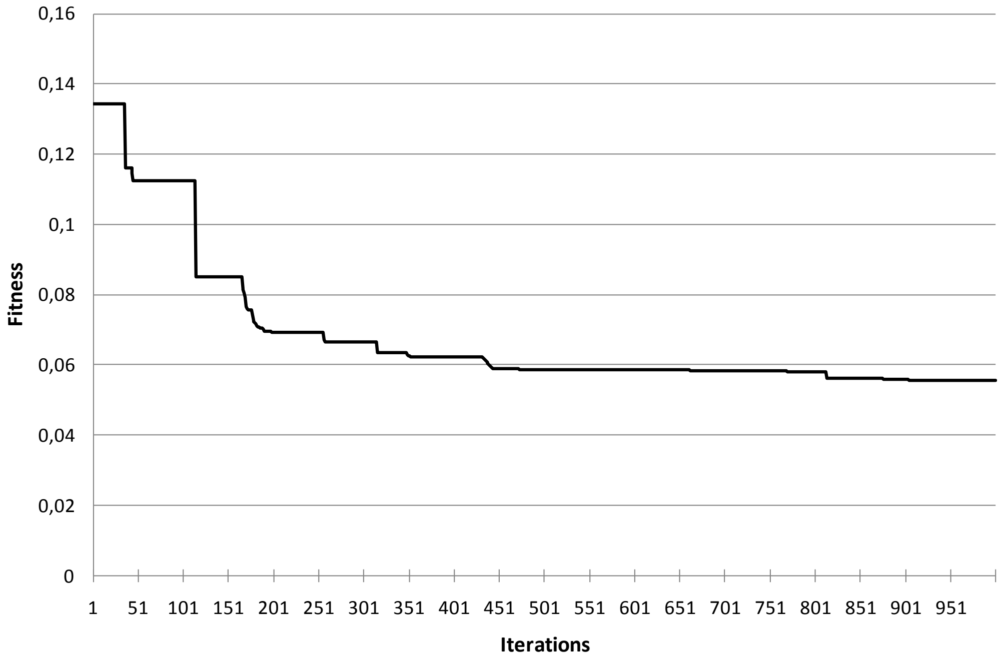

Figure 6-16 – Evolution of the Fitness Function for One Typical Run

Furthermore, in order to detail the behaviour of the algorithm, it is interesting to analyse the behaviour of the two main terms of the objective function: active power losses (shown in Figure 6-17) and microgeneration shedding (shown in Figure 6-18).

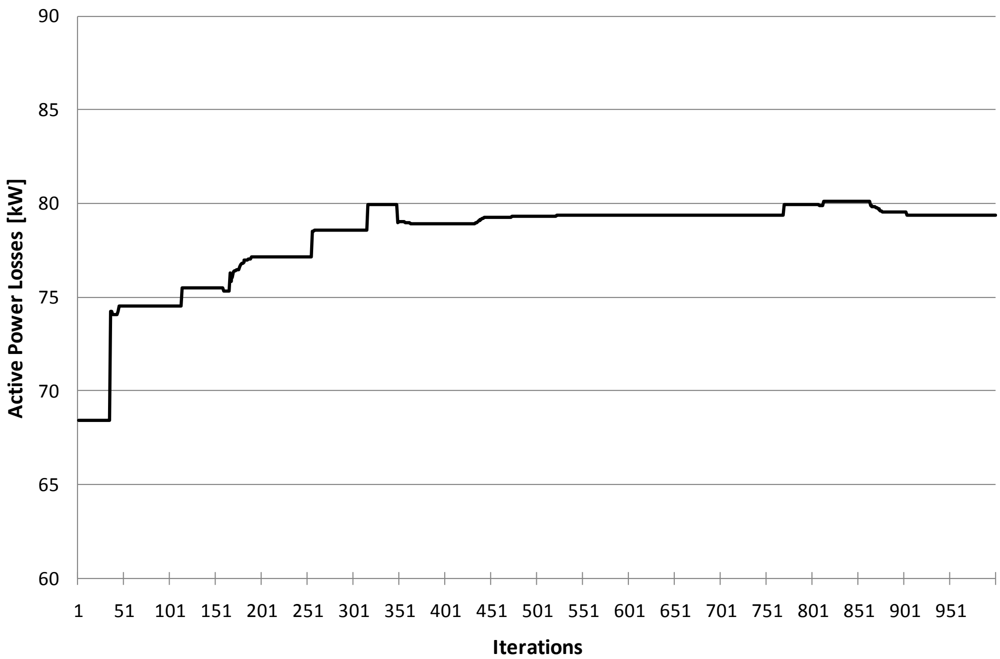

Figure 6-17 – Evolution of the Active Power Losses

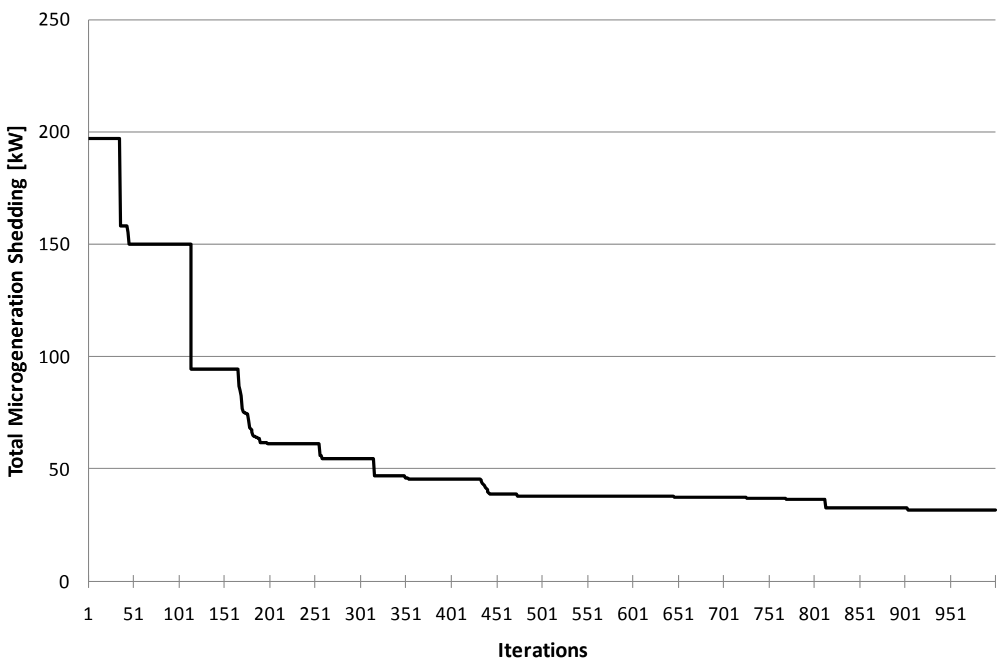

Figure 6-18 – Evolution of the Microgeneration Shedding

From Figure 6-17, it can be seen that active power losses increase slightly although loss minimization was one of the goals set in the objective function. This is due to the fact that voltage values were high above the admissible limits in the operation scenario considered here and since the algorithm succeeded in bringing down voltage profiles, currents in branches have increased and, consequently, so have active power losses.

Regarding microgeneration shedding, it can be observed from Figure 6-18 that the amount of microgeneration shedding required was reduced significantly from the initial situation up to the final solution reached after the end of 1000 iterations. The total amount of microgeneration shedding required in each LV network is presented in Table 6-4.

Table 6-4 – Microgeneration Shedding required in each LV Network

Network	Microgeneration Shedding [kW]	Microgeneration Shedding [%]
Microgrid 1	15,0	26,22
Microgrid 2	13,1	22,84
Microgrid 3	0,1	0,04
Microgrid 4	3,4	1,13
Microgrid 5	0	0
Microgrid 6	0	0

As can be observed from this table, Microgrid 1 and Microgrid 2 required some shedding of their microgeneration output in order to lower voltage values (shown in Figure 6-20).

Furthermore, the evolution of the maximum voltage value in the MV network is presented in Figure 6-19. As can be observed, the algorithm converges to a value slightly above 1,02 p.u.

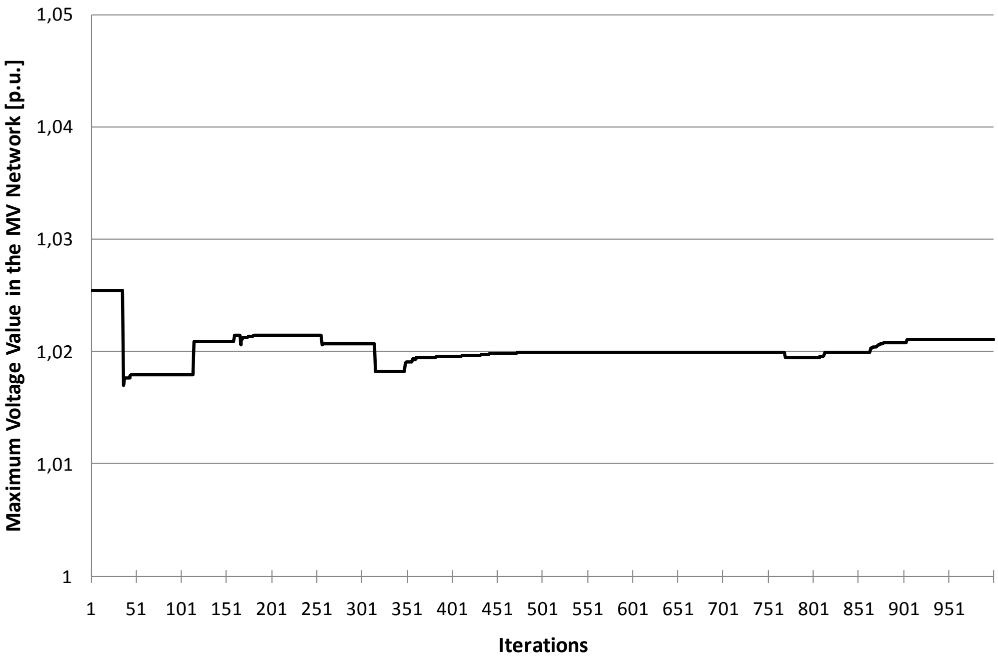

Figure 6-19 – Evolution of the Maximum Voltage in the MV Network

In addition, Figure 6-20 shows the maximum voltage value in Microgrid 1 and Microgrid 2 which are the LV networks with highest voltage profiles.

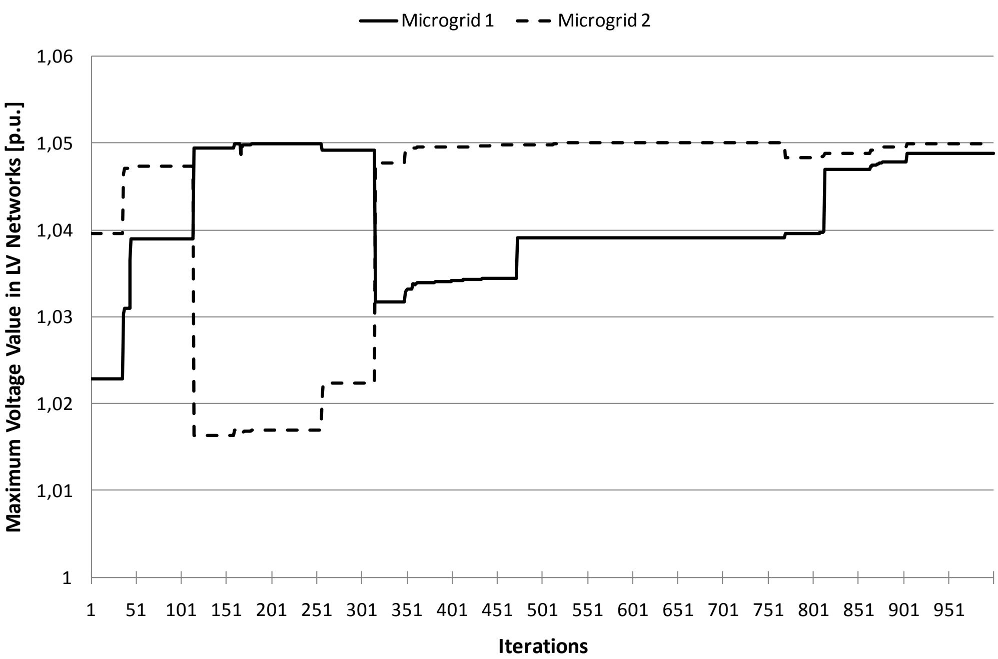

Figure 6-20 – Maximum Voltage in Microgrid 1 and Microgrid 2

As can be seen from this figure, the maximum voltage converges to a value close to the limit considered of 1,05 p.u. This is due to the fact that high DG and microgeneration penetration was considered in this operation scenario, which caused significant voltage rise. As seen in Chapter 4, above this limit a penalty for the voltage deviation is applied in order to keep voltage profiles within admissible limits. It can be seen that the algorithm was able to successfully bring voltage profiles back within admissible limits. On the other hand, the algorithm tries to minimize active power losses, which is achievable if voltage profiles are kept high enough.

A summary of the maximum voltage values in each microgrid with and without voltage control is presented in Table 6-5. As can be seen, the voltage profiles were considerably high, especially in Microgrid 1 and Microgrid 2, but the voltage control algorithm was able to bring them back into admissible limits.

Table 6-5 – Maximum Voltage Values Before and After the Voltage Control Algorithm

	Maximum Voltage [p.u.]	
	Initial	**Final**
MV Network	1,0358	1,0210
Microgrid 1	1,0874	1,0489
Microgrid 2	1,0851	1,0499
Microgrid 3	1,0644	1,0498
Microgrid 4	1,0654	1,0500
Microgrid 5	1,0385	1,0245
Microgrid 6	1,0336	1,0194

Finally, in order to further validate the results obtained, a comparison was made between the values obtained through the ANN model and using the three-phase power flow algorithm presented in Chapter 4 for the best solution achieved. The results are presented in Table 6-6.

Table 6-6 – Comparison between Three-phase Power Flow Results and ANN Results for the Best Solution Found

	Maximum Voltage [p.u.]		Error [%]
	3-phase PF	**ANN**	
Microgrid 1	1,0481	1,0489	0,001
Microgrid 2	1,0485	1,0499	0,001
Microgrid 3	1,0484	1,0498	0,001
Microgrid 4	1,0485	1,0500	0,001
Microgrid 5	1,0220	1,0245	0,002
Microgrid 6	1,0169	1,0194	0,002

As can be seen from Table 6-6, the ANN models provided good quality results when compared to the full model using the three-phase power flow routine developed.

However, when analysing the initial conditions using the three-phase power flow, it was seen that voltage values were above the limit only in one or two buses of a particular feeder while the remaining voltage values were still comparatively low. On the other hand, analysing the results obtained from the voltage control algorithm revealed that voltage profiles were too low in some buses which had no prior voltage problems. This suggested that the algorithm was curtailing more microgeneration than strictly required in order to lower the voltage profiles. Since voltage is a local problem that can be restricted to one feeder, the solution of curtailing microgeneration at the global LV network level penalizes all buses in a similar way, independent of their individual voltage values. Consequently, the approach developed resulted in excessive microgeneration curtailment based on the LV network model that was used.

In order to further develop this issue, several tests have been conducted in order to analyse in detail the behaviour of the LV networks employed. First of all, as can be seen in Section 6.1.2, the three LV networks used here have very different characteristics: LV network 1 has some generation imbalances between the feeders (and even more between phases) and some microgeneration units are connected to the end of the feeders; LV network 2 has more uniformly distributed microgeneration units; and LV network 3 has very few microgeneration units altogether.

It was seen that these differences between networks and between feeders were indeed causing the algorithm to shed more microgeneration than required for maintaining voltage profiles within admissible limits since the algorithm would affect all feeders uniformly. This revealed that using global LV network models provides pessimistic results.

Consequently, ANN models for each of the feeders of the all the LV networks employed were developed and included in the optimization algorithm, which meant passing from three ANN models (one for each LV network) to nine ANN models (one for each LV feeder, considering three feeders in LV network 1, five feeders in LV network 2 and one feeder in LV network 3).

The results obtained with this approach revealed that developing ANN models for each feeder of the LV networks is able to improve the quality of the results significantly by reducing the amount of microgeneration shedding required. Figure 6-21 shows the amount of microgeneration shedding that was required using feeder models, which is considerably lower than in the previous case (presented in Figure 6-18).

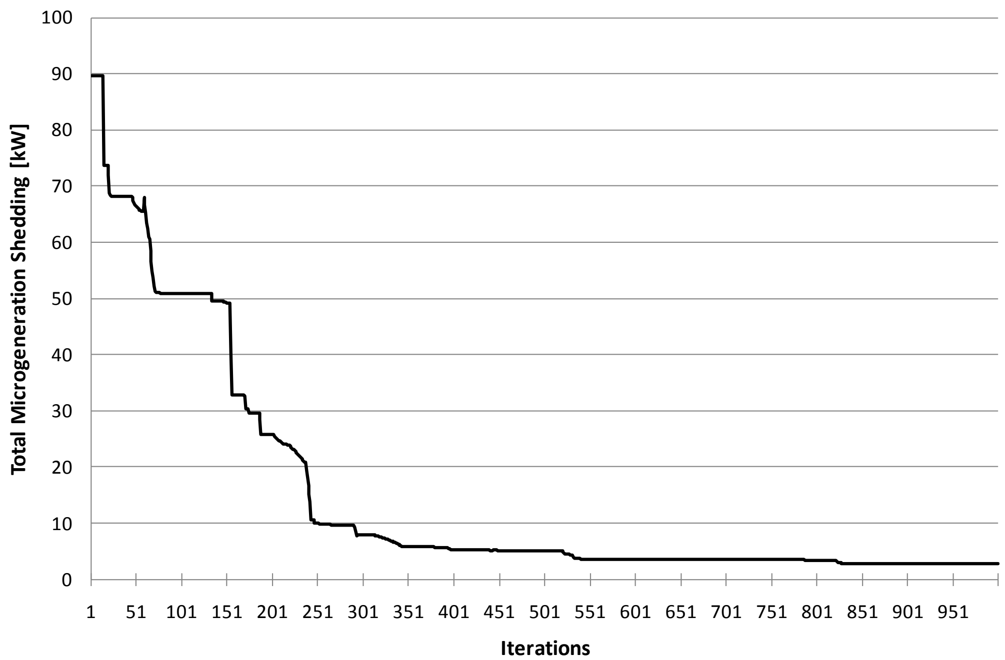

Figure 6-21 – Evolution of the Microgeneration Shedding using ANN Feeder Models

Moreover, Figure 6-22 and Figure 6-23 illustrate the maximum voltage value for each iteration for Microgrid 1 and Microgrid 2, respectively, for each of their three feeders.

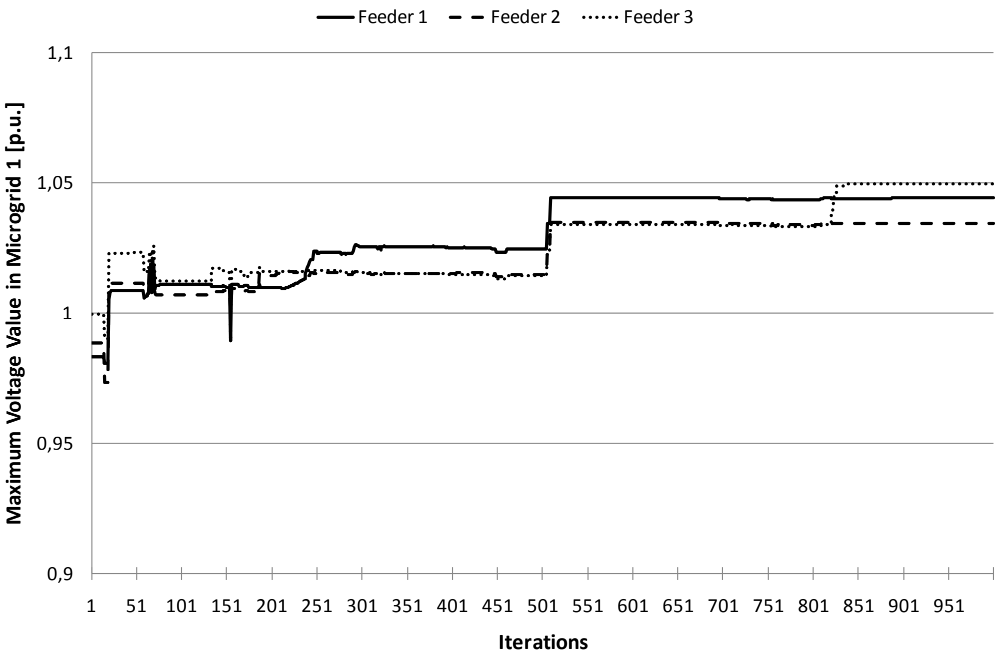

Figure 6-22 – Maximum Voltage in each Feeder of Microgrid 1 using ANN Feeder Models

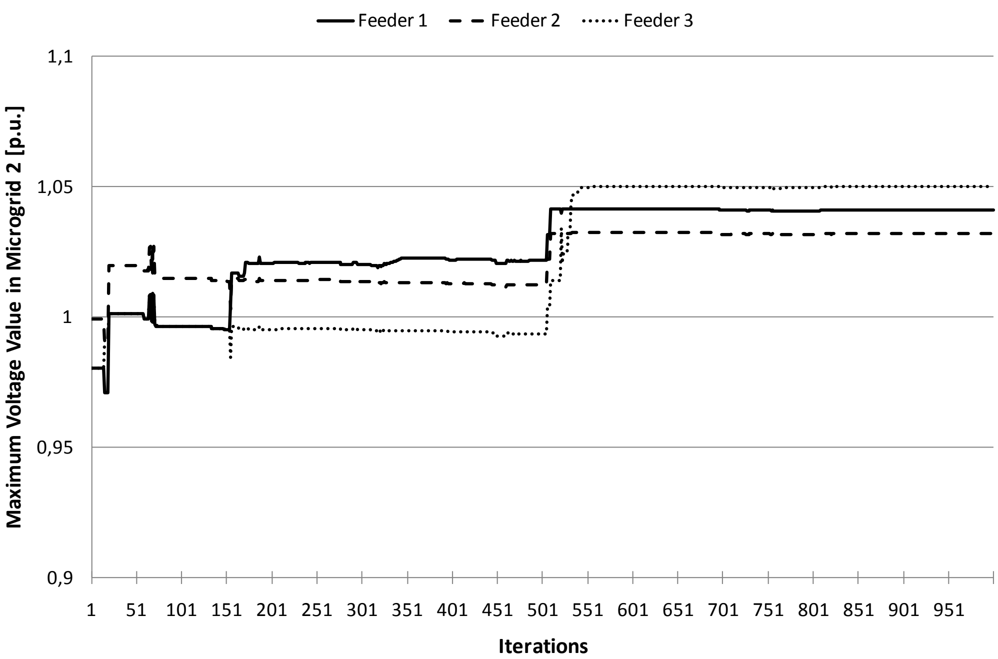

Figure 6-23 – Maximum Voltage in each Feeder of Microgrid 2 using ANN Feeder Models

It can be seen that Feeder 3 is the feeder with highest voltage profiles both in Microgrid 1 and Microgrid 2. Some microgeneration shedding was required in this feeder in order to bring voltage values back into admissible limits (*i.e.* 1,05 p.u.).

As can be observed from Table 6-7, the amount of microgeneration shedding required using the feeder models is considerably lower than in the previous case with the global network model. It must be noted that the amount of microgeneration shedding required was almost insignificant in all feeders, apart from Feeder 3 of Microgrid 1 and Microgrid 2 since they were the feeders with highest voltage values. In fact, the percentage of microgeneration shedding in Feeder 3 of Microgrid 1 and Microgrid 2 was 29,70% and 26,74%, respectively.

Table 6-7 – Microgeneration Shedding required in each LV Network using ANN Feeder Models

Network	Microgeneration Shedding [kW]	Microgeneration Shedding [%]
Microgrid 1	1,2	2,06
Microgrid 2	1,3	2,29
Microgrid 3	0	0
Microgrid 4	0,3	0,11
Microgrid 5	0	0
Microgrid 6	0	0

6.3.3.2 Results from Twenty-Four Operating Periods

In this section, results obtained from the voltage support tool are presented for a 24-hour horizon, corresponding to twenty-four consecutive operating periods. This will allow evaluating the coupling introduced by the constraint related to the maximum number of OLTC transformer tap changes allowed in two consecutive time-periods as presented in Section 4.2.5.2. The voltage control algorithm was run using ANN models for each feeder of each microgrid as discussed in Section 6.3.3.1.

For this run of simulations, it is assumed that generation scheduling data is always available for the next hour, as well as forecast information for renewable generation and for load, considering a 24-hours time horizon. The network data for the test case used here is included in Appendix B. The scenarios used in the simulation were obtained by applying the load and generation profiles to the total load installed capacity and total generation capacity, respectively. The profiles for the several generation units and for the load are included in Appendix C. The operation scenario considered is summarized in Table 6-8.

Table 6-8 – Scenario for Load and Generation

Network	Total Load Installed Capacity [MVA]	Total Generation Installed Capacity [MVA]
MV Network	17,440	4,280
Microgrid 1	0,308	0,082
Microgrid 2	0,308	0,082
Microgrid 3	1,512	0,433
Microgrid 4	1,512	0,433
Microgrid 5	0,126	0,017
Microgrid 6	0,126	0,017

For these twenty-four scenarios simulated, a value of 0,5 was given to the decision parameter α. In this section, only the results considered most relevant will be presented.

According to the objective function defined in Chapter 4, active power losses minimization was one of the goals to achieve. Figure 6-24 compares the base situation (without any type of voltage control – labelled as **Initial** in the figure) and the result obtained using the voltage support tool developed (labelled as **Final** in the figure). It can be seen that total network losses were successfully decreased during night-time but have increased slightly during day-time.

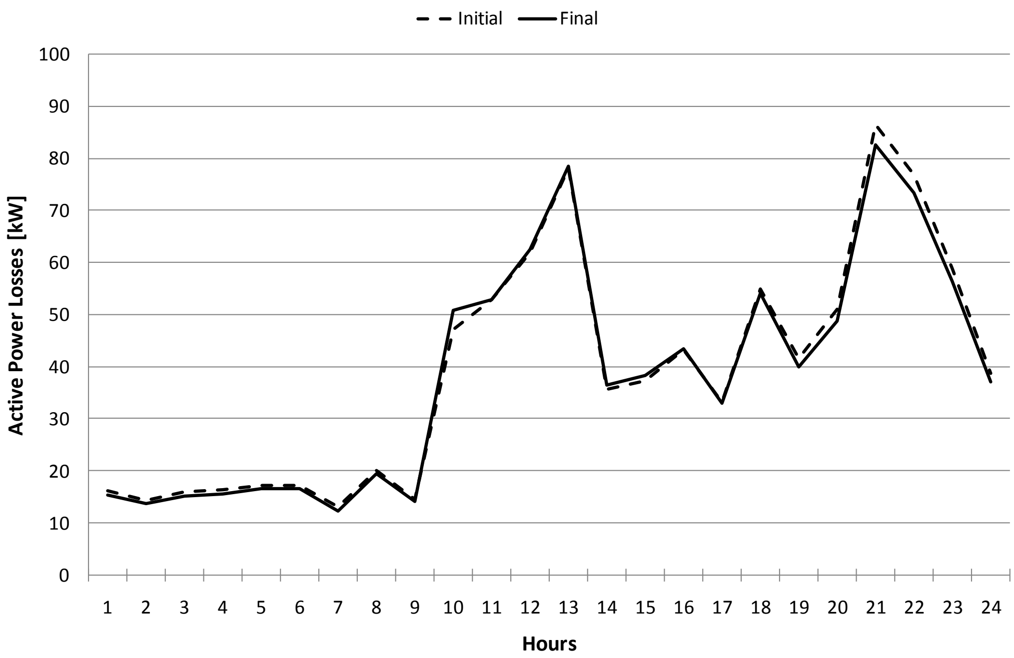

Figure 6-24 – Total Active Power Losses in the MV Network

The maximum voltage values in the MV network for a 24-hours time horizon are depicted in Figure 6-25.

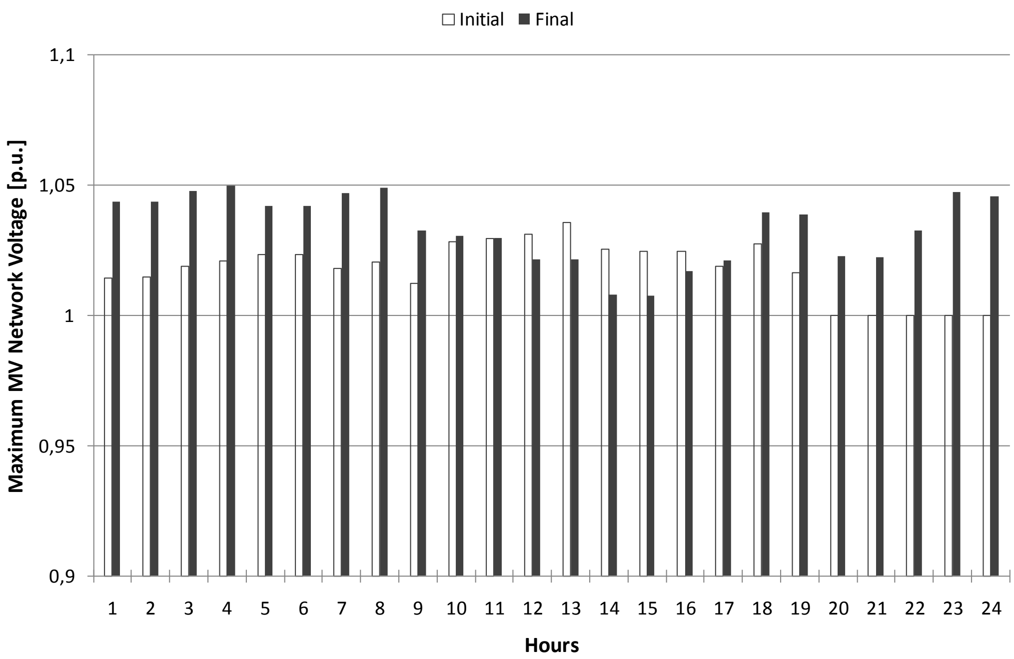

Figure 6-25 – Maximum Voltage Values in the MV Network

Concerning the voltage profiles shown for the MV network, it may be observed that voltage values were already inside an admissible range. However, it can be seen that voltage values after running the voltage control algorithm have decreased during day-time (around 13h) because voltages at the LV side were particularly high, as will be seen later. Furthermore, voltage values have increased during night-time since the algorithm was trying to reduce active power losses, which can be achieved by raising voltage levels. This behaviour is mostly due to the influence of the OLTC transformer (shown in Figure 6-26).

Figure 6-26 shows the tap values at the OLTC transformer. According to the modelling of the transformer with taps on the secondary side, tap values above 1 raise the voltage on the secondary of the transformer. Consequently, lower tap values are used when voltage profiles are typically high and higher tap values are used when voltage profiles are low. As can be observed, the constraint used for limiting the number of switching actions of the OLTC transformer was able to limit the number of tap changes in consecutive one-hour periods. In fact, only one tap change was required from one period to the other.

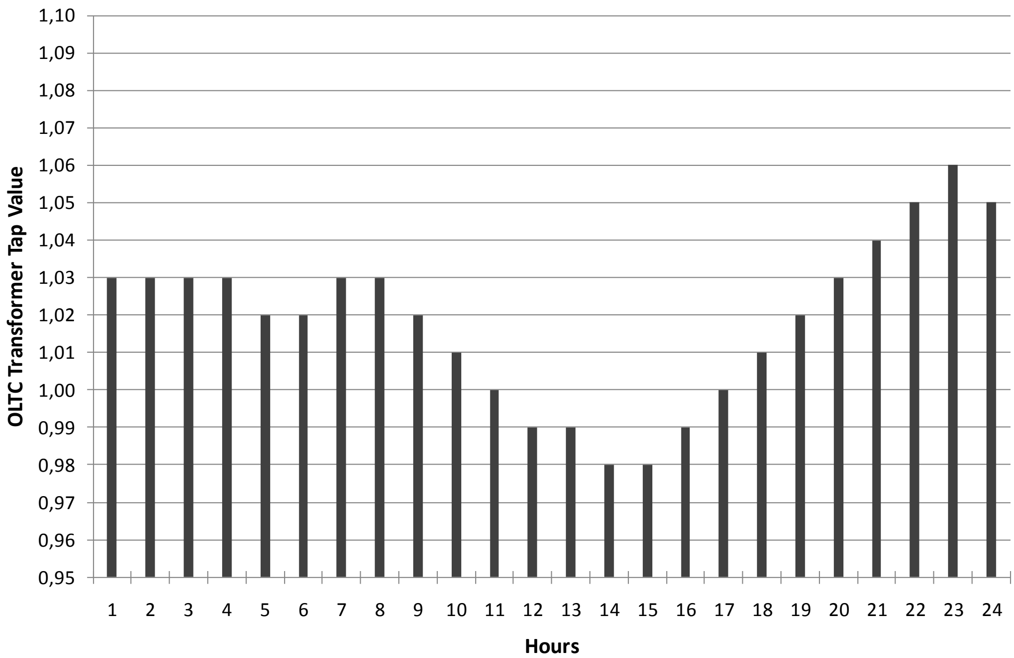

Figure 6-26 – OLTC Transformer Tap Values

Furthermore, the contribution of the MV-connected DG units for voltage support is presented in Figure 6-27 to Figure 6-29. The DG units were used to supply reactive power (positive values) or absorb reactive power (negative values), according to the operation scenario requirements. It can be observed that there are some considerable variations in the reactive power from all DG sources since no restrictions were imposed (as in the case of the OLTC transformer), although all these units exhibit a similar behaviour. The DG sources tend to absorb reactive power during day-time when generation profiles are high and voltage values are above the admissible limits. Conversely, during nigh-time, DG sources supply reactive power in order to raise voltage profiles and help in reducing active power losses.

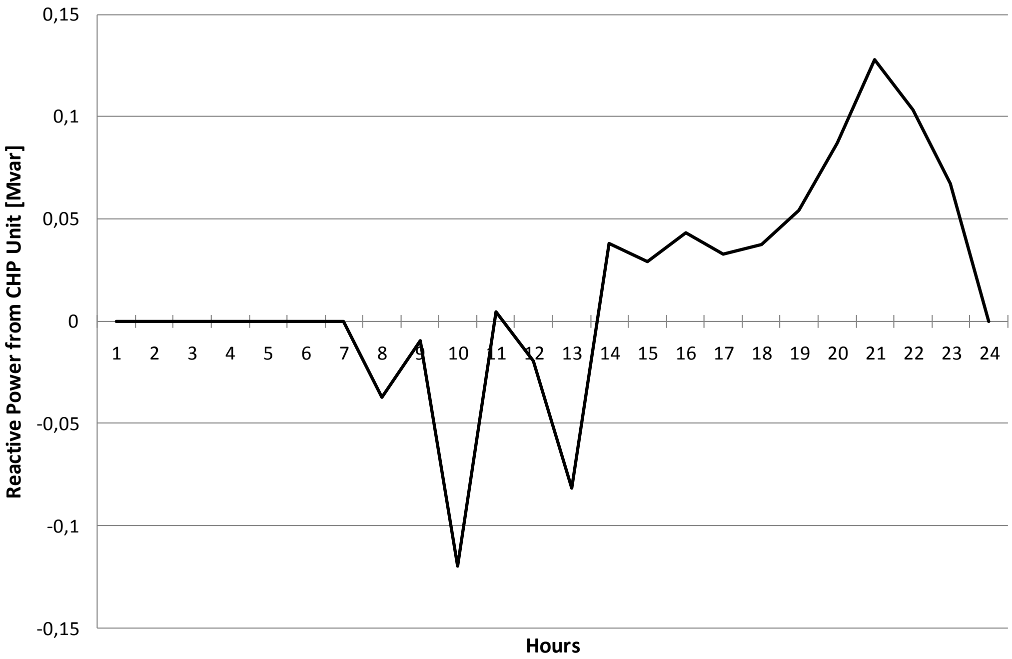

Figure 6-27 – Reactive Power from the CHP Unit

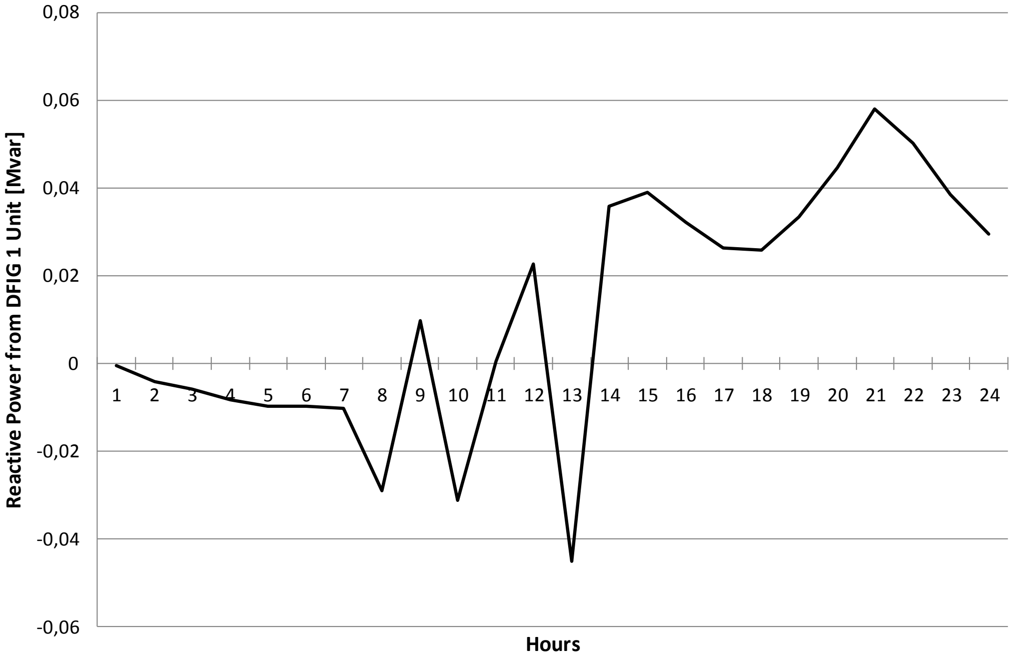

Figure 6-28 – Reactive Power from the DFIG 1 Unit

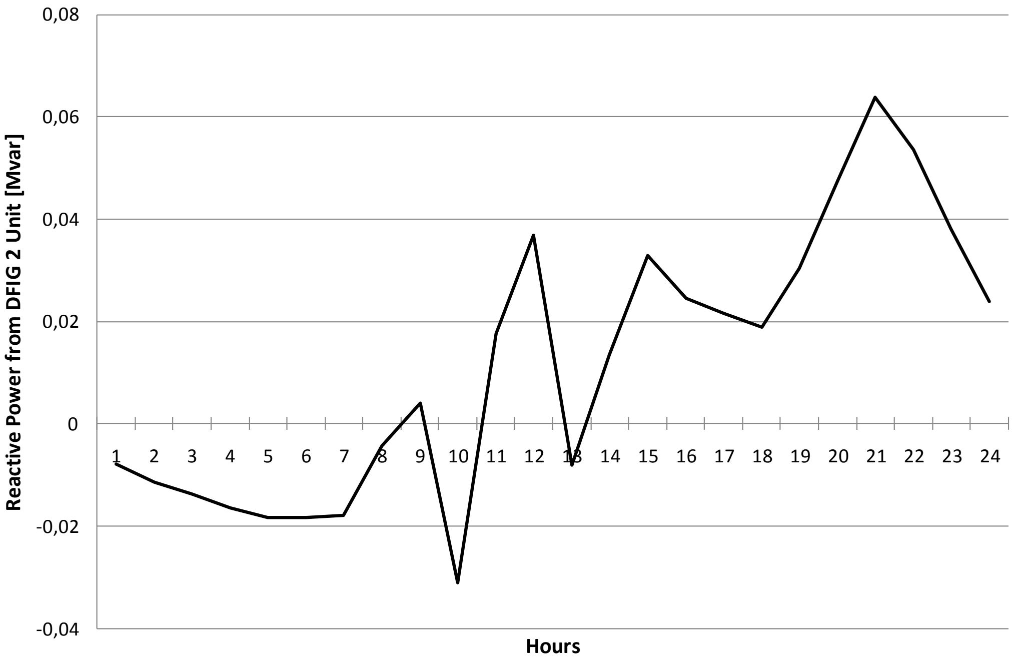

Figure 6-29 – Reactive Power from the DFIG 2 Unit

Figure 6-30 shows the maximum voltage value in Microgrid 1 for each hour of the day.

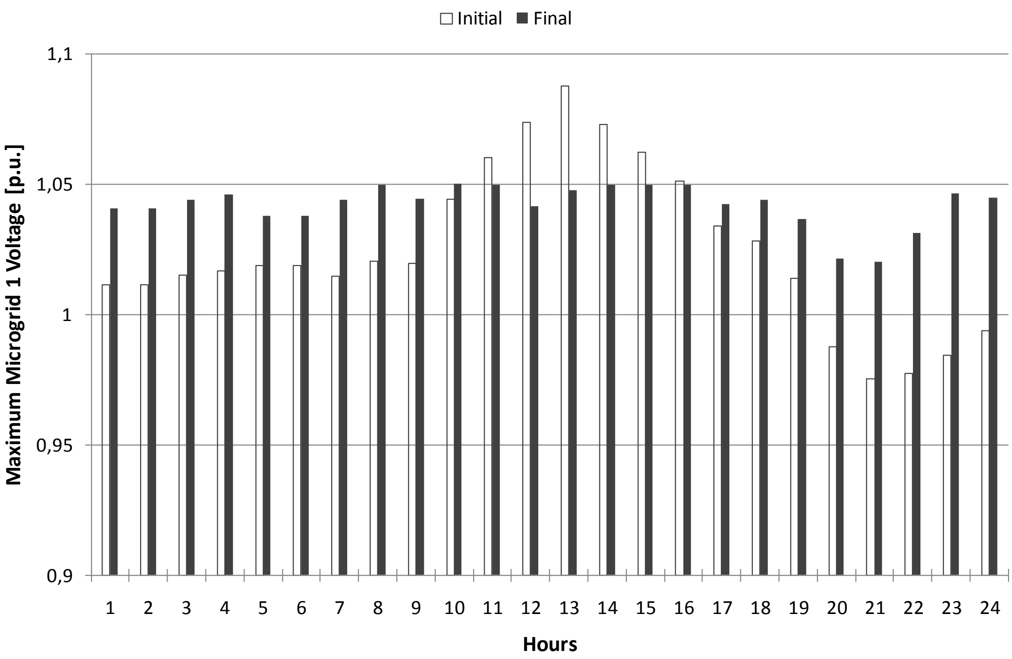

Figure 6-30 – Maximum Voltage Values in Microgrid 1

As can be observed from this figure, without voltage control, voltage values were well above the admissible range of +5% due to the massive penetration of PV-based microgeneration, especially since this particular microgrid is the one with highest microgeneration penetration. In this case, the PV panels generate power at peak capacity around 13h, which is outside the peak demand hours and therefore force excess generation through the MV/LV transformer.

Using the voltage support tool it was possible to bring these values back to an admissible range by curtailing excess microgeneration in some critical hours of the day.

Figure 6-31 to Figure 6-33 show the maximum voltage values in each of the three feeders of Microgrid 1.

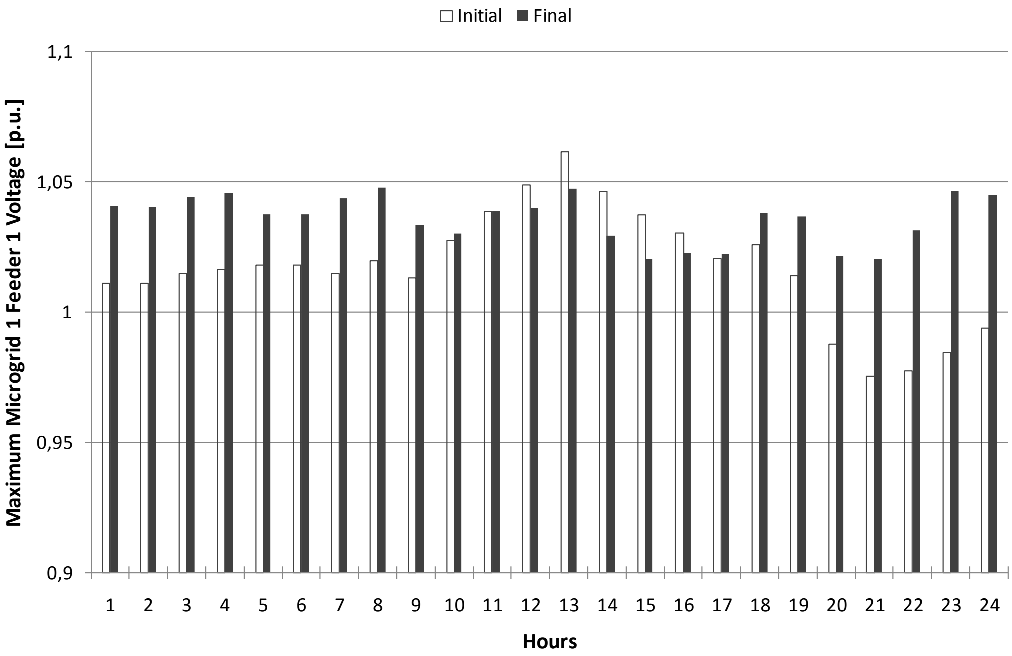

Figure 6-31 – Maximum Voltage Values in Feeder 1 of Microgrid 1

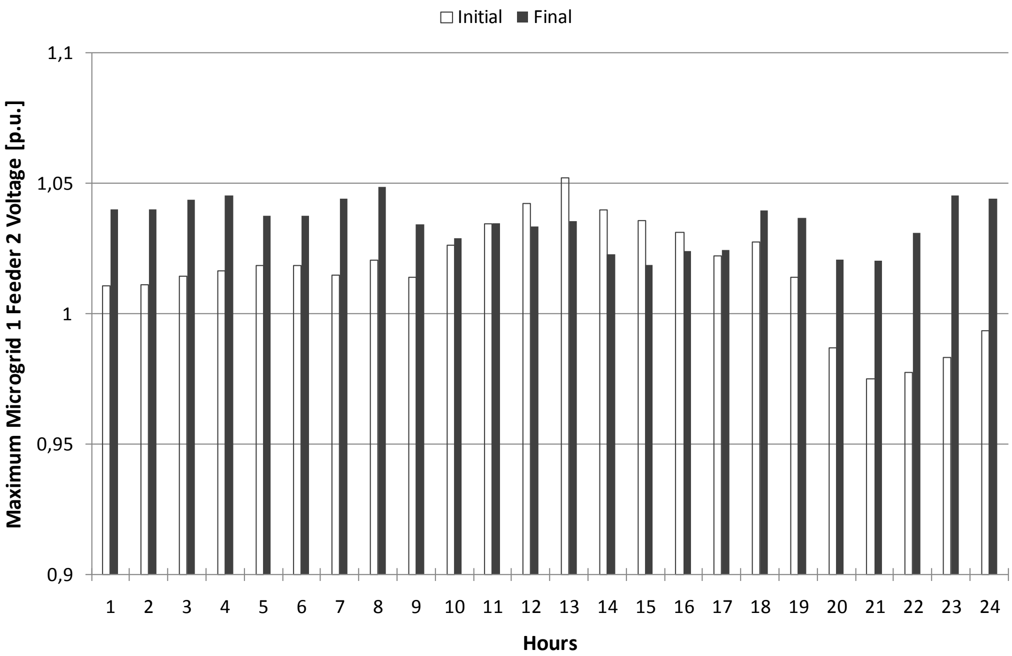

Figure 6-32 – Maximum Voltage Values in Feeder 2 of Microgrid 1

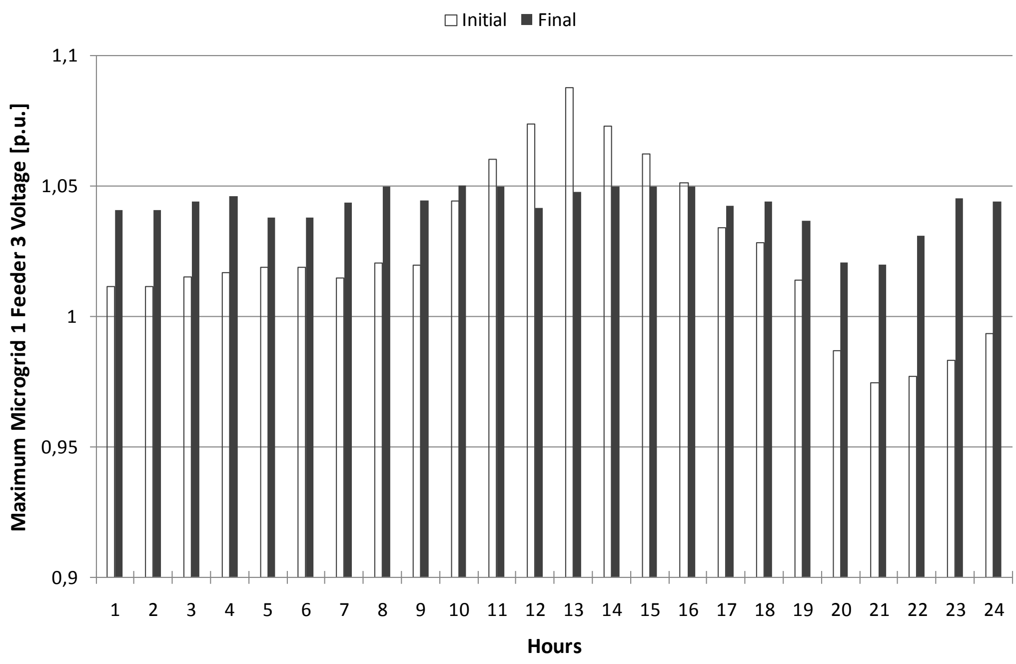

Figure 6-33 – Maximum Voltage Values in Feeder 3 of Microgrid 1

As can be observed, the critical feeder is Feeder 3 since it has the highest voltage profiles, while Feeder 1 and Feeder 2 only marginally exceed voltage limits at 13h. In fact, given that the load and generation profiles are similar in all feeders, the voltage profiles of Microgrid 1 (shown in Figure 6-30) are a replicate of the worst feeder in terms of voltage values, *i.e.* Feeder 3 (shown in Figure 6-33).

In order to be able to bring the LV voltage profiles back inside the admissible range, some microgeneration shedding was required in Microgrid 1, as can be observed from Figure 6-34.

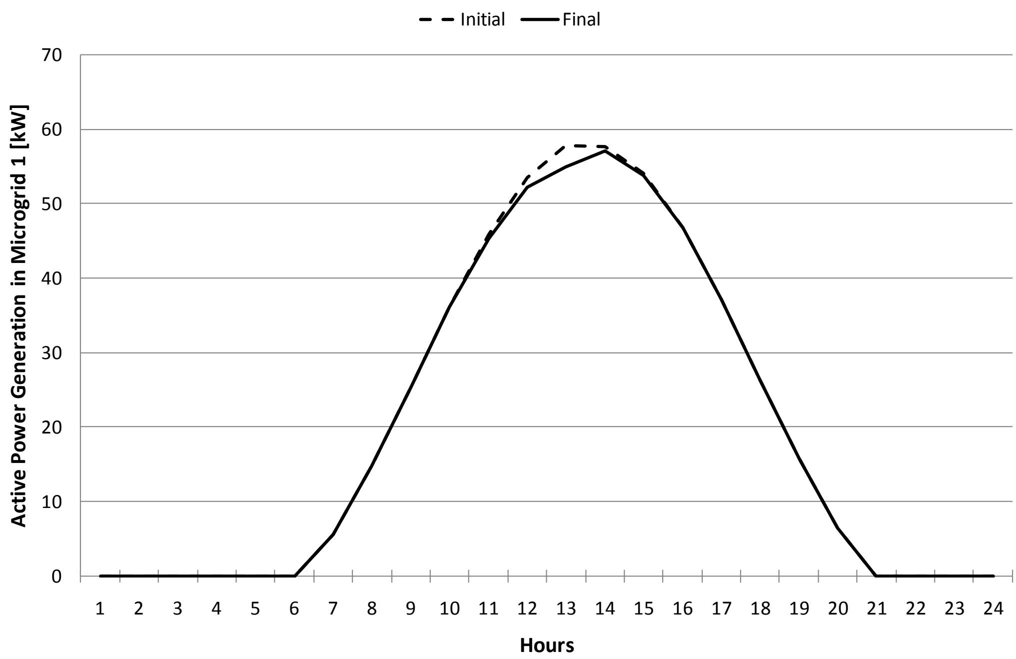

Figure 6-34 – Total Active Power Generation in Microgrid 1

The amount of microgeneration shedding required for each of the three feeders is shown in Figure 6-35 to Figure 6-37. As can be observed, the most significant amount of microgeneration shedding (in percentage) required was in Feeder 3, which is expected since it is the feeder with highest voltage profiles. In Feeder 1, a small amount of microgeneration shedding was required at 13h while in Feeder 2 no microgeneration shedding was required at all.

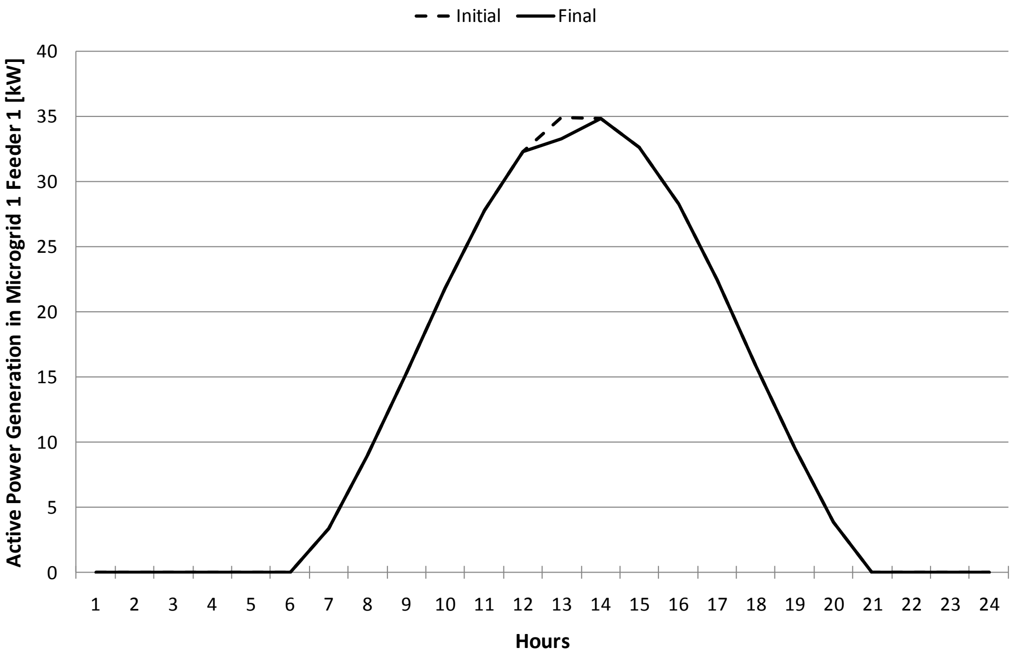

Figure 6-35 – Total Active Power Generation in Feeder 1 of Microgrid 1

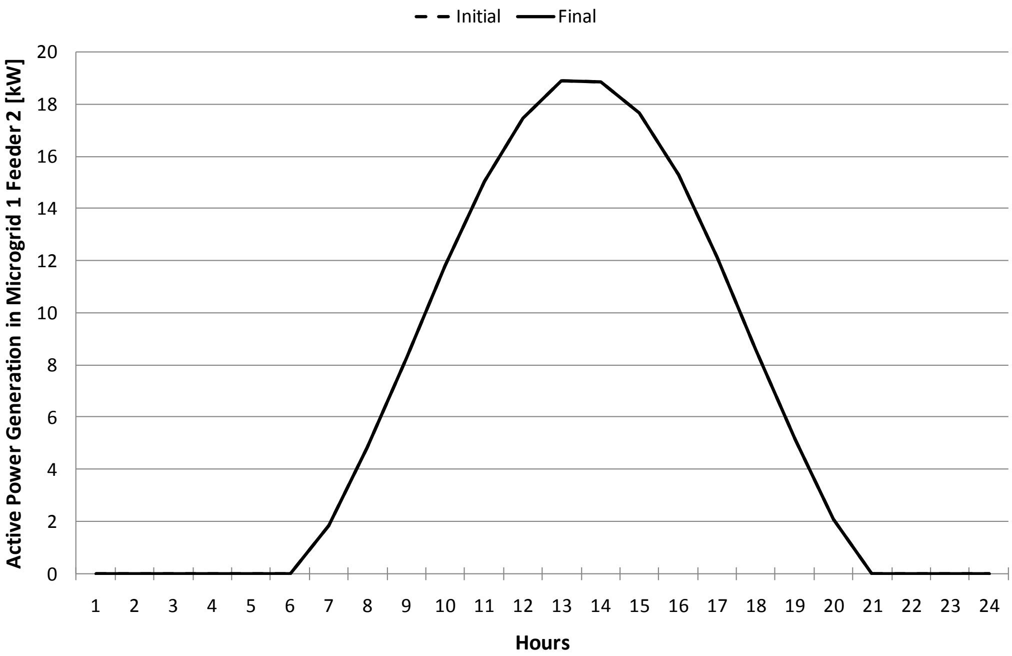

Figure 6-36 – Total Active Power Generation in Feeder 2 of Microgrid 1

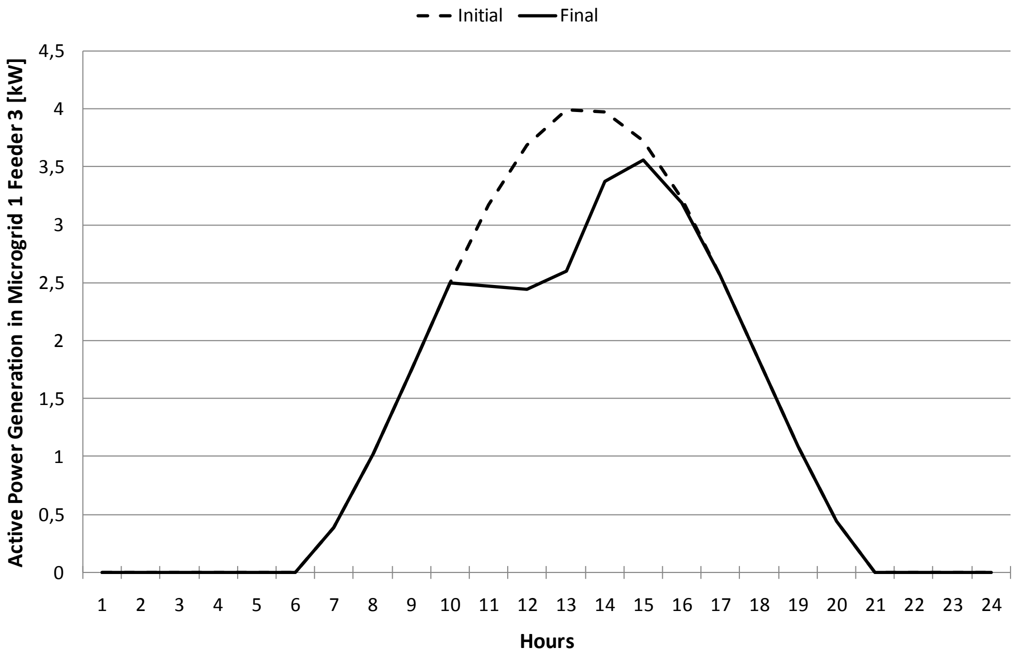

Figure 6-37 – Total Active Power Generation in Feeder 3 of Microgrid 1

Furthermore, it is interesting to note that the profile of microgeneration that was shed follows quite closely the load profile (presented in Appendix C). This effect is particularly visible in Feeder 3 (shown in Figure 6-37). This makes sense since as load increases, the imbalance between load and generation decreases, thus requiring a smaller amount of microgeneration shedding.

A similar situation can be observed in Microgrid 3. Figure 6-38 to Figure 6-42 illustrate the maximum voltage values in each of the three feeders of Microgrid 3.

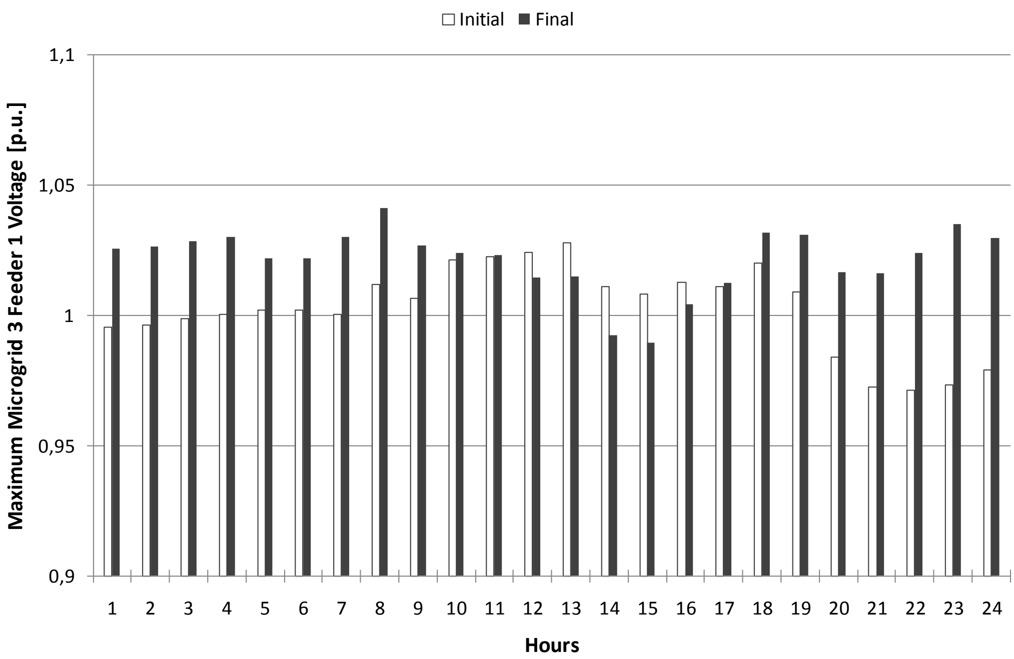

Figure 6-38 – Maximum Voltage Values in Feeder 1 of Microgrid 3

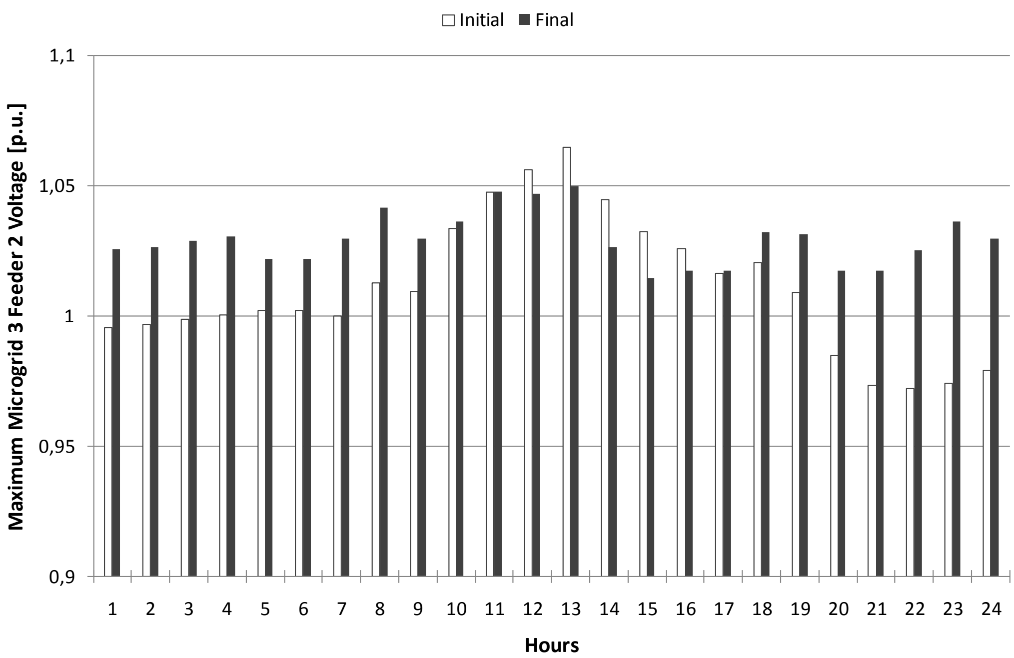

Figure 6-39 – Maximum Voltage Values in Feeder 2 of Microgrid 3

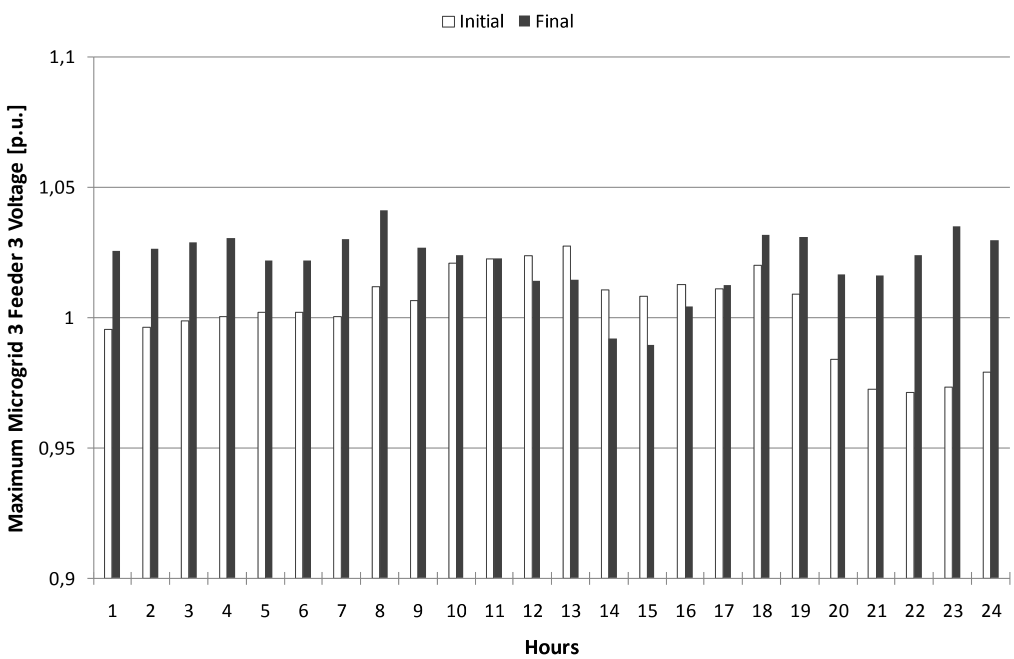

Figure 6-40 – Maximum Voltage Values in Feeder 3 of Microgrid 3

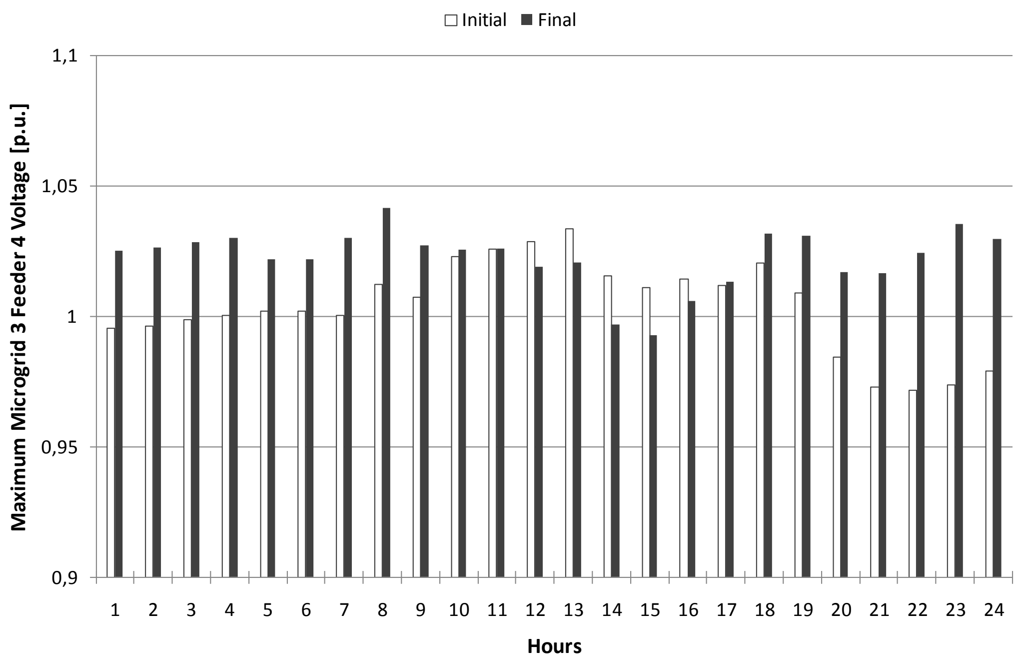

Figure 6-41 – Maximum Voltage Values in Feeder 4 of Microgrid 3

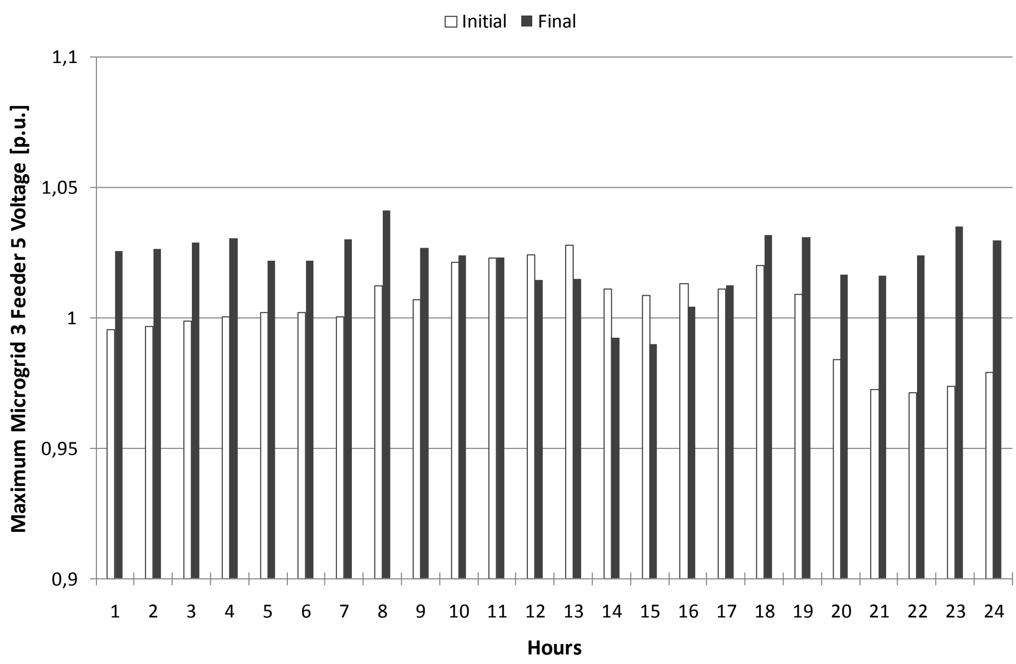

Figure 6-42 – Maximum Voltage Values in Feeder 5 of Microgrid 3

As can be observed from these figures, only Feeder 2 has voltage values outside the admissible range at 12h and 13h.

The amount of microgeneration shedding required for each of the five feeders of Microgrid 3 is shown in Figure 6-43 to Figure 6-47. As can be observed, microgeneration shedding only occurred in Feeder 2, since it is the only feeder with voltage values above the limit at around

13h. In the remaining feeders, no violations occurred and, consequently, no microgeneration shedding was required.

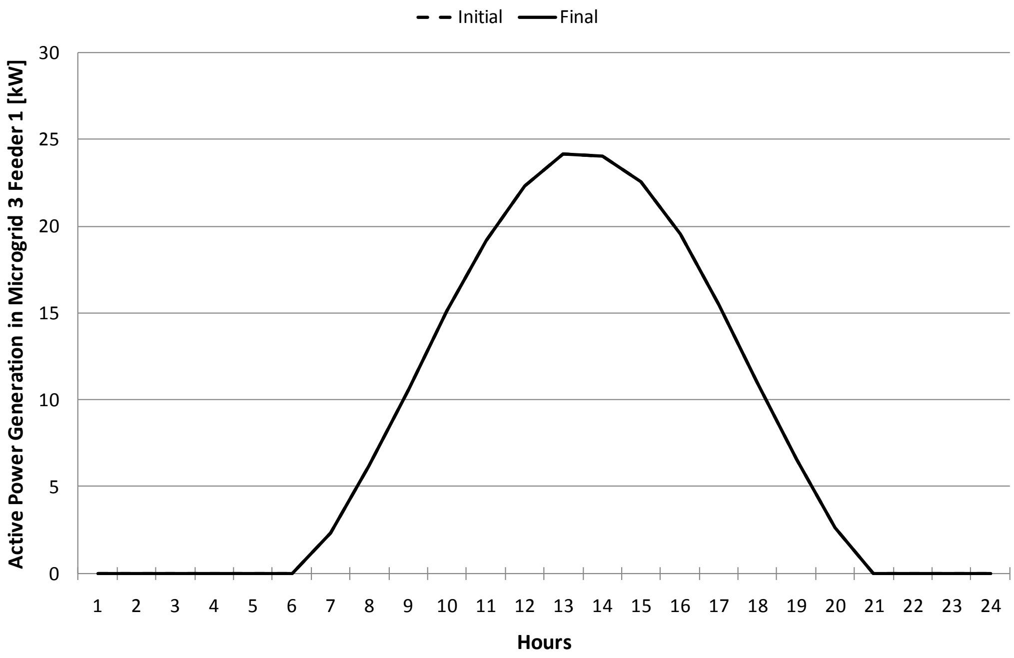

Figure 6-43 – Total Active Power Generation in Feeder 1 of Microgrid 3

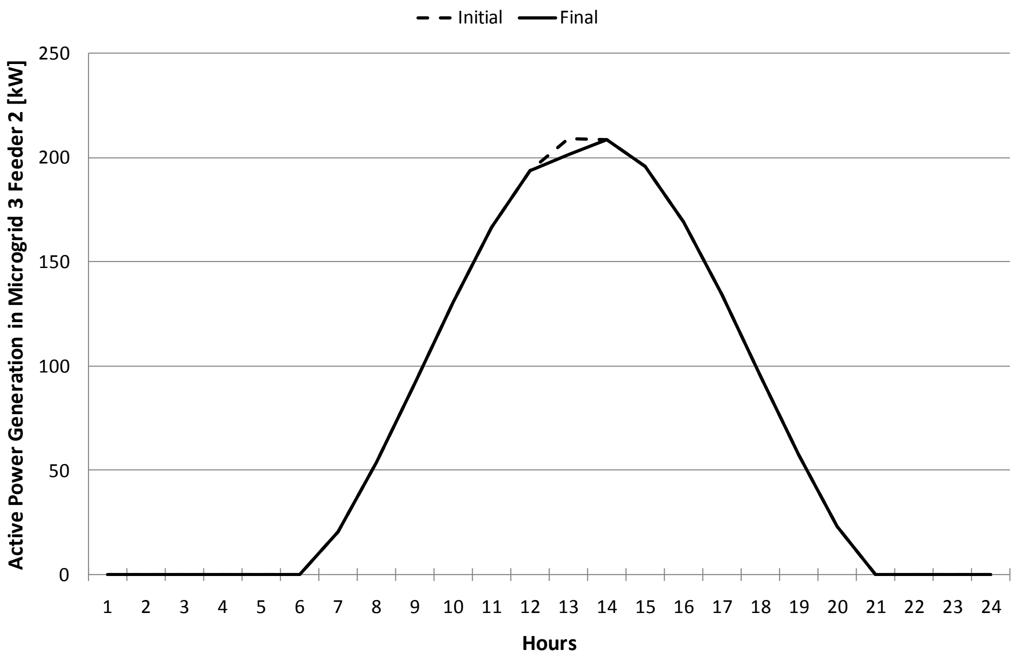

Figure 6-44 – Total Active Power Generation in Feeder 2 of Microgrid 3

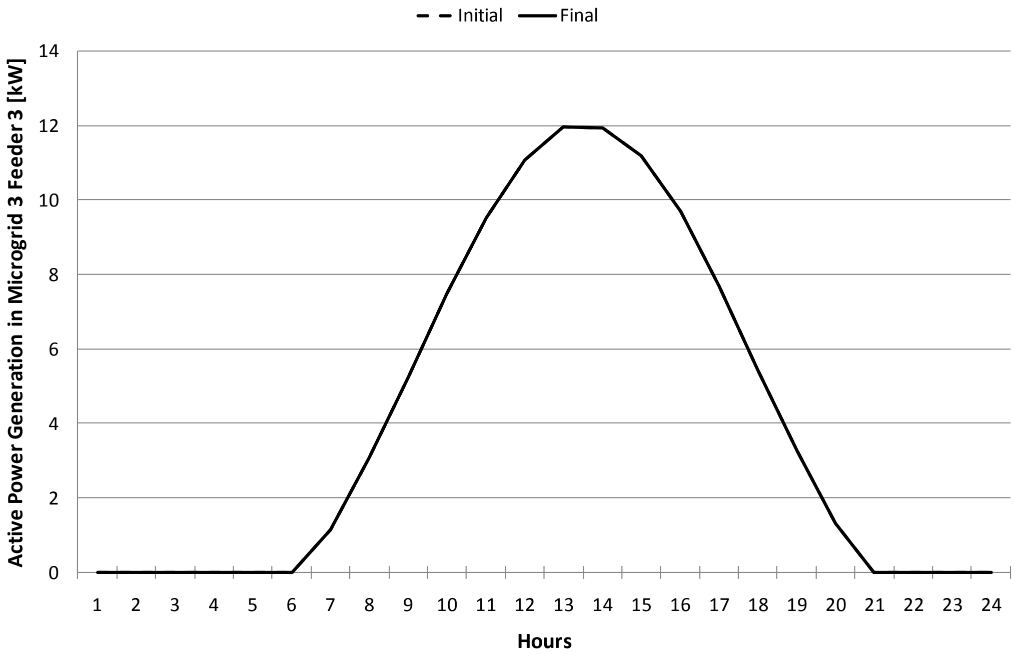

Figure 6-45 – Total Active Power Generation in Feeder 3 of Microgrid 3

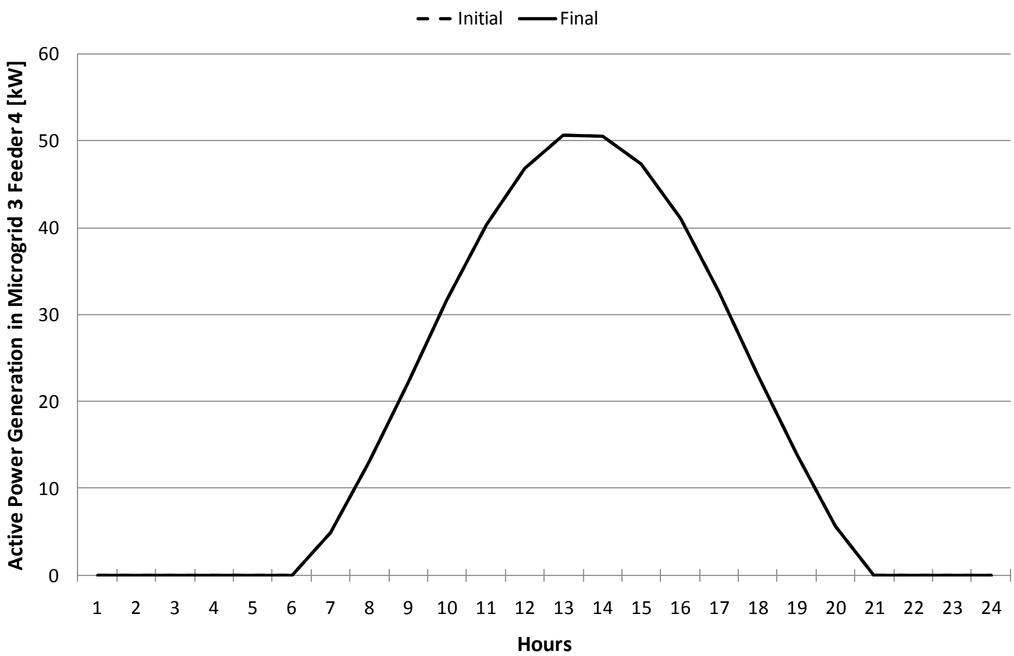

Figure 6-46 – Total Active Power Generation in Feeder 4 of Microgrid 3

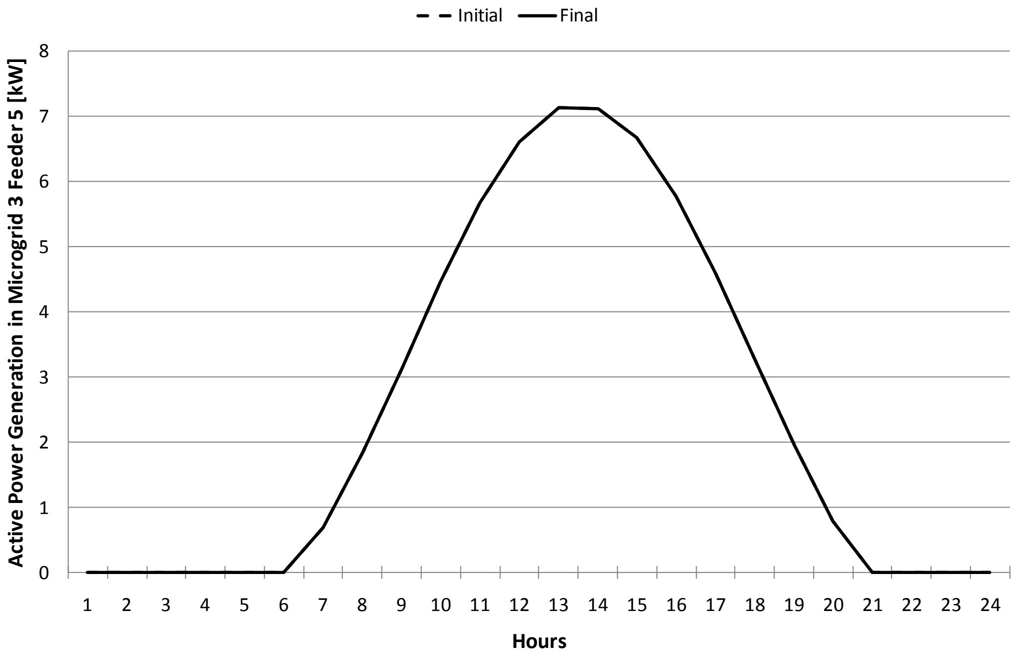

Figure 6-47 – Total Active Power Generation in Feeder 5 of Microgrid 3

Finally, the maximum voltage profiles in Microgrid 5 are shown in Figure 6-48.

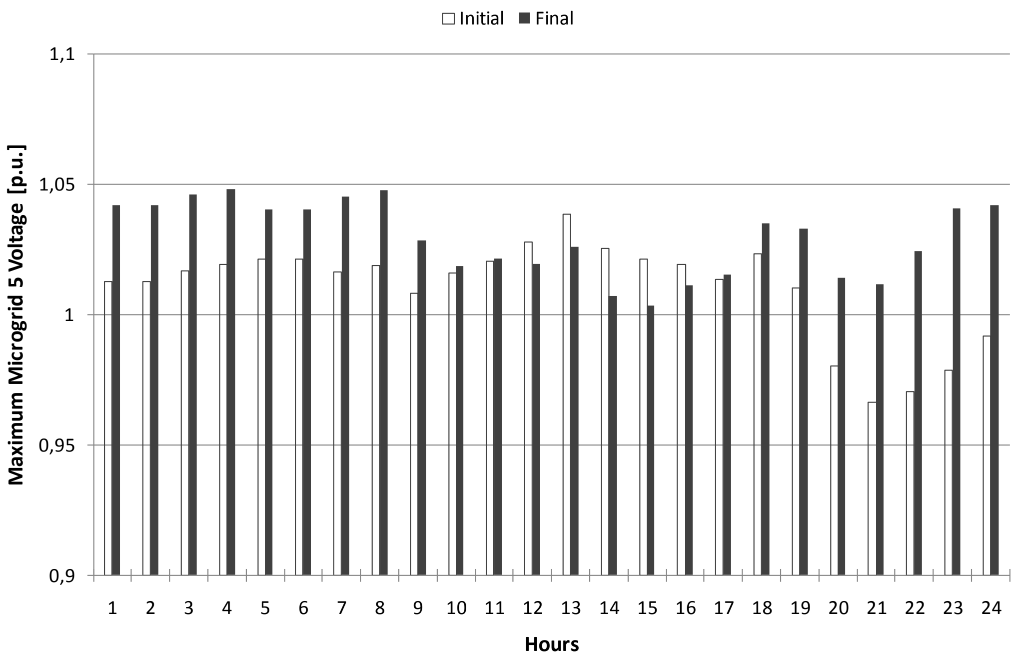

Figure 6-48 – Maximum Voltage Values in Microgrid 5

In this case, the voltage profiles are all within admissible limits and therefore no microgeneration shedding is required, as can be observed in Figure 6-49. As previously discussed, Microgrid 5 has only one feeder with very few microgeneration units and this is why there are no significant overvoltages as it happens in the case of Microgrid 1.

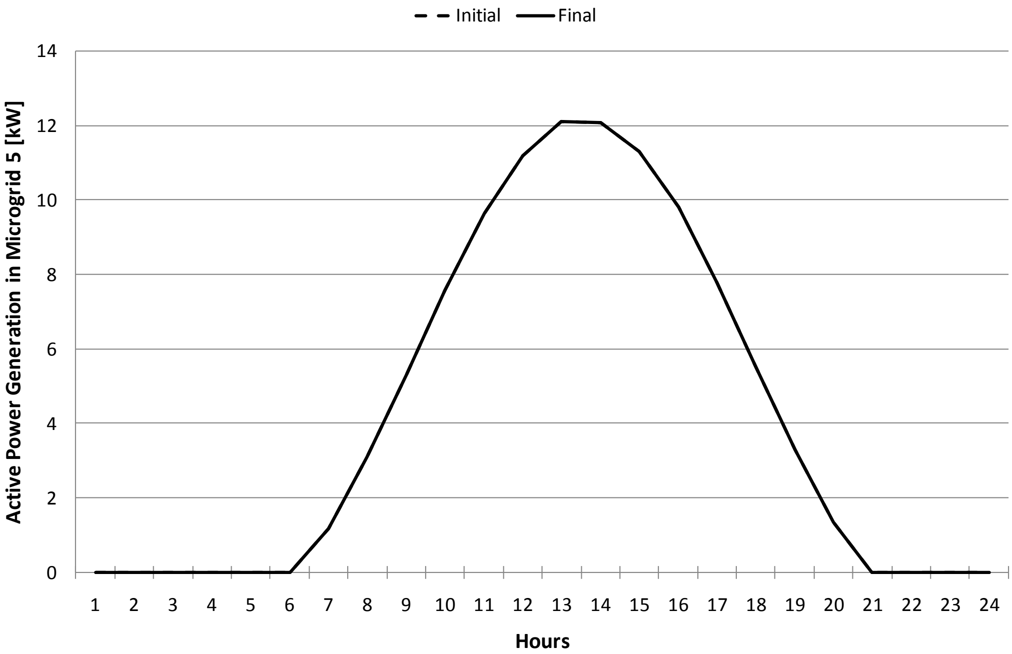

Figure 6-49 – Total Active Power Generation in Microgrid 5

6.4 Ancillary Services Market for Voltage Control

In this section, some results from the ancillary services market simulator for voltage control (as presented in Chapter 5) are presented and discussed.

6.4.1 Initial Considerations

For evaluating the performance of the ancillary services market simulator, several simulations corresponding to different operating scenarios have been performed using a test case developed specifically for this thesis. For this test case, described in the following sections, the MV network presented in Section 6.1.1.2 was used.

First of all, it was considered that the var suppliers bidding to the market are the 4 MV-connected DG sources (the CHP unit, the DFIG unit, the Diesel unit and the Hydro unit) and the 5 microgrids, shown in Figure 6-2. Although the Hydro unit is based on an induction generator, it is able to participate in the var capacity use market since it has an individual capacitor bank that is used for supplying reactive power in order to ensure the power factor required by the DSO.

The microgrids were modelled as an equivalent load (corresponding to the sum of all LV loads) and an equivalent generator (corresponding to the sum of all microgeneration units), as can be seen in Figure 6-2. Contrary to what was considered in Section 6.3, it is assumed that these microgrids have a combination of different types of microgenerators – both controllable (such as microturbines) and non-controllable (such as PV) – in order to ensure that some reactive power can be injected into the main MV network.

Furthermore, the two microgrid operation policies presented in Chapter 5 are considered here:

- Microgrid "good-citizen" policy;
- Microgrid "ideal-citizen" policy.

Despite the fact that the prices used for the var bids from the several units are not real prices, the price paid for reactive power supply for DG units in Portugal was considered as reference[41], which in the year of 2009 was around 16 €/Mvar.h. Therefore, the prices of the bids were defined with values close to this reference by introducing some variations according to the type of generating unit and the amount of reactive energy required. The amount of reactive power that can be offered to the market is defined based on the active power generation of each unit in order to guarantee an adequate power factor value.

6.4.2 Performance of the Algorithm

In this section, some results from the market settlement for a specific operation period are included.

As previously mentioned, the market simulator developed is assumed to run for the operation period of one day. The results presented next correspond to the two most extreme situations that occur in that period. The first scenario to be detailed corresponds to the hour of lowest demand (corresponding to a valley period) and the second scenario analysed corresponds to the hour of peak load (with highest demand for reactive power).

For both scenarios considered, the DSO was able to achieve the market settlement successfully, without voltage limits violations and without branch overloads.

6.4.2.1 Valley Hour

A scenario corresponding to the valley hour (characterized by reduced power consumption) is presented in order to illustrate the performance of the ancillary services market simulator for voltage control that was developed.

The scheduling for active power is assumed to have been performed with success for all generating units (including RES, based on forecast tools) for the corresponding operating period. The results from the scheduling are presented in Table 6-9. It should be stressed that in this scenario, given the low load profiles, the DG units and microgrids are able to generate the whole amount of power required. This means that no active power is imported from the upstream HV network.

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[41] According to the Portuguese tariff for selling reactive energy to final clients in the HV level, which is the price paid to DG units for supplying reactive energy.
For more information see http://www.erse.pt/pt/electricidade/tarifaseprecos/Paginas/default.aspx

Table 6-9 – Generation Scheduling for the Valley Hour

Generation Unit	P [MW]
CHP	0,734
Hydro	0,142
DFIG	0,597
Diesel	0,597
Microgrid 1	0
Microgrid 2	0,125
Microgrid 3	0,125
Microgrid 4	0,125
Microgrid 5	0,125
Total	**2,695**

The load scenario considered is presented in Appendix B. For the valley scenario, the percentage of load regarding the installed capacity is 0,3. In order to determine active and reactive power, a value of $tan(\varphi) = 0{,}27$ was considered.

The reactive power bids from the several participants in the ancillary services market for voltage control are presented in the following tables, considering both the “good-citizen” and “ideal-citizen” microgrid policies. The main difference that can be observed between the two situations is that, as previously explained, in the “good-citizen” policy the microgrids do not participate in the var capacity use market.

The reactive power bids from the several market players are based on their reactive power generation capacity considering their expected active power output.

Table 6-10 – Reactive Power Bids for the var Market (“Good-citizen”) for the Valley Hour

Generation Unit	Block Number	Quantity [Mvar.h]	Price [€/Mvar.h]
CHP	1	0,07	14
	2	0,11	15
	3	0,11	16
Hydro	1	0,008	16
	2	0,01	17
	3	0,01	18
DFIG	1	0,02	15
	2	0,04	16
	3	0,05	17
Diesel	1	0,07	14
	2	0,08	15
	3	0,08	16
HV Network	1	2	19
	2	2	19
	3	2	19

Table 6-11 – Reactive Power Bids for the var Market ("Ideal-citizen") for the Valley Hour

Generation Unit	Block Number	Quantity [Mvar.h]	Price [€/Mvar.h]
CHP	1	0,07	14
	2	0,1	15
	3	0,1	16
Hydro	1	0,008	16
	2	0,015	17
	3	0,015	18
DFIG	1	0,02	15
	2	0,04	16
	3	0,05	17
Diesel	1	0,07	14
	2	0,08	15
	3	0,08	16
HV Network	1	2	19
	2	2	19
	3	2	19
Microgrid 1	1	0.025	13
Microgrid 2	1	0.025	13
Microgrid 3	1	0.025	13
Microgrid 4	1	0.025	13
Microgrid 5	1	0.025	13

The main results from the market settlement are presented in the figures and tables below.

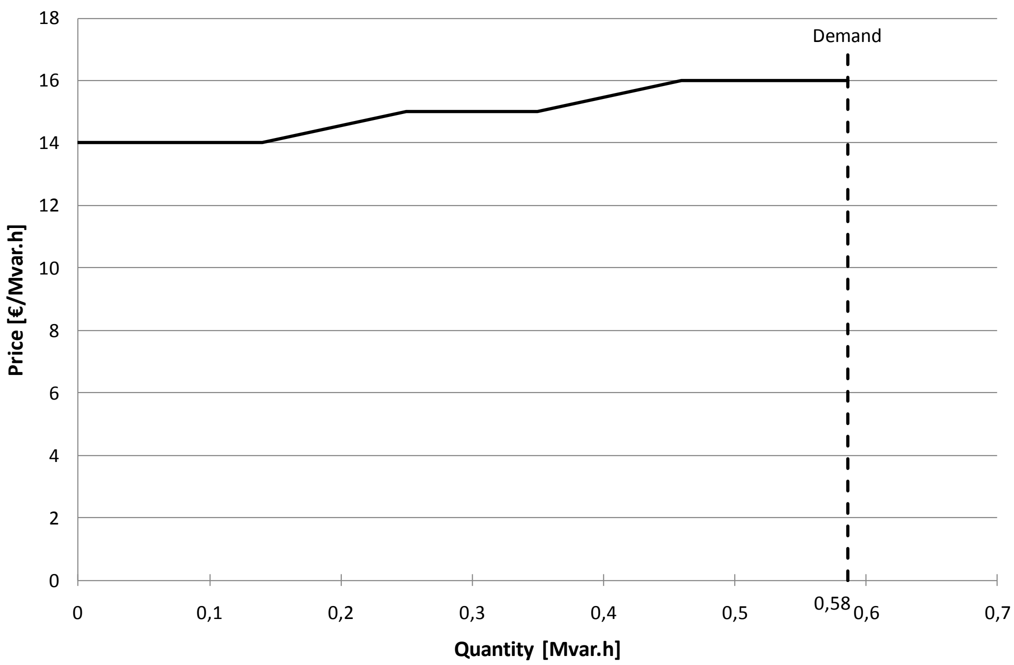

Figure 6-50 – Results from the Market Settlement ("Good-citizen" Policy) for the Valley Hour

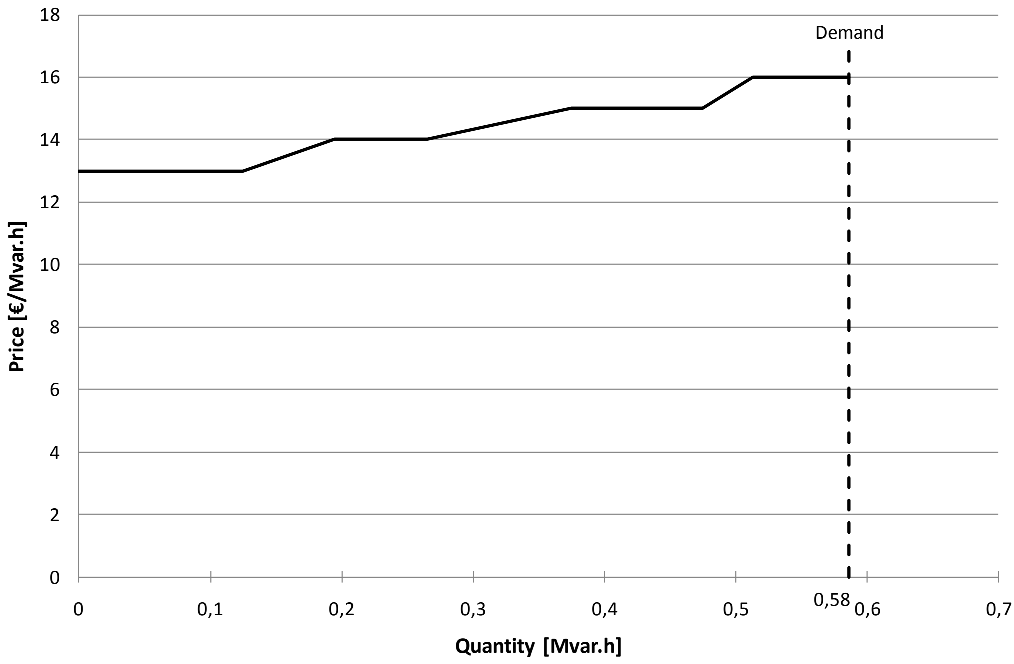

Figure 6-51 – Results from the Market Settlement ("Ideal-citizen" Policy) for the Valley Hour

Figure 6-50 and Figure 6-51 show the evolution towards market settlement considering the "good-citizen" and the "ideal-citizen" policies, respectively. As seen previously, the bid of the marginal unit defines the uniform market price. Concerning both microgrid policies, the market price is the same – 16 €/Mvar.h, so there is no particular advantage for the DSO in terms of cost minimization in this case.

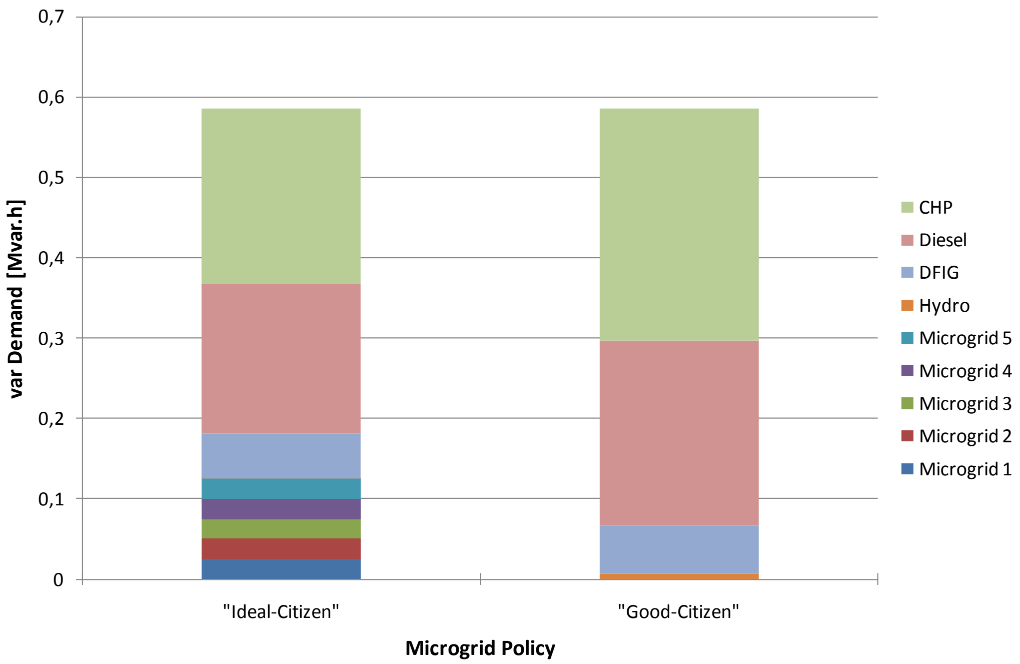

Figure 6-52 – Selected Bids ("Good-citizen" Policy vs. "Ideal-citizen" Policy) for the Valley Hour

The selected var bids per technology are presented in Figure 6-52, comparing the "good-citizen" and the "ideal-citizen" policies.

Table 6-12 and Table 6-13 show the var bids and prices after the market settlement considering the "good-citizen" and the "ideal-citizen" policies, respectively. In the "good-citizen" policy, all DG units have some of their bids cleared and there is no need for importing var from the upstream HV network in order to guarantee the reactive power needs of the MV network. In the "ideal-citizen" policy, all microgrids have their offers cleared in the var market, in addition to the DG units.

Table 6-12 – Bids and Prices ("Good-citizen") for the Valley Hour

Generation Unit	Q [Mvar.h]	Price [€/Mvar.h]	Cost [€]
CHP	0,290	16,00	4,634
Hydro	0,010	16,00	0,101
DFIG	0,006	16,00	0,960
Diesel	0,230	16,00	3,679
Total	**0,586**	**–**	**9,374**

Table 6-13 – Bids and Prices ("Ideal-citizen") for the Valley Hour

Generation Unit	Q [Mvar.h]	Price [€/Mvar.h]	Cost [€]
CHP	0,218	16,00	4,634
Hydro	0,001	16,00	0,012
DFIG	0,055	16,00	0,881
Diesel	0,187	16,00	2,988
Microgrid 1	0,025	16,00	0,400
Microgrid 2	0,025	16,00	0,400
Microgrid 3	0,025	16,00	0,400
Microgrid 4	0,025	16,00	0,400
Microgrid 5	0,025	16,00	0,400
Total	**0,586**	**–**	**9,373**

A summary of the results obtained from the OPF-like algorithm is presented in Table 6-14.

Table 6-14 – Results from the OPF-like algorithm for the Valley Hour

Maximum Voltage [p.u.]	Minimum Voltage [p.u.]	Active Energy Losses [MW.h]	Reactive Energy Losses [Mvar.h]
1,050	1,048	0,001	0,000

6.4.2.2 Peak Hour

A scenario for the peak hour (corresponding to the highest demand for energy) is also presented for illustrating the performance of the ancillary services market simulator for voltage control.

Again, the scheduling for active power is assumed to have been performed with success for all generating units (including RES, based on forecast tools) for the corresponding operating period. The results from the scheduling are presented in Table 6-15. Contrary to the previous case, in this scenario there is active power import from the upstream HV network since demand values are high.

Table 6-15 – Generation Scheduling for the Peak Hour

Generation Unit	P [MW]
CHP	1,839
Hydro	0,425
DFIG	1,313
Diesel	1,288
HV Network	0,628
Microgrid 1	0,250
Microgrid 2	0,250
Microgrid 3	0,250
Microgrid 4	0,250
Microgrid 5	0,250
Total	**6,743**

The load scenario considered is presented in Appendix B. For the peak scenario, the percentage of load regarding the installed capacity is 0,7. In order to determine active and reactive power, a value of $tan(\varphi) = 0{,}28$ was considered.

The reactive power bids from the several participants in the ancillary services market for voltage control are presented in the following tables, considering both the “good-citizen” and “ideal-citizen” microgrid policies.

Table 6-16 – Reactive Power Bids for the var Market (“Good-citizen”) for the Peak Hour

Generation Unit	Block Number	Quantity [Mvar.h]	Price [€/Mvar.h]
CHP	1	0.19	16,00
	2	0.27	17,00
	3	0.27	18,00
Hydro	1	0,02	18,00
	2	0,03	19,00
	3	0,03	20,00
DFIG	1	0,06	17,00
	2	0,10	18,00
	3	0,10	19,00
Diesel	1	0,10	16,00
	2	0,20	17,00
	3	0,20	18,00
HV Network	1	2,00	21,00
	2	2,00	21,00
	3	2,00	21,00

Table 6-17 – Reactive Power Bids for the var Market ("Ideal-citizen") for the Peak Hour

Generation Unit	Block Number	Quantity [Mvar.h]	Price [€/Mvar.h]
CHP	1	0.19	16,00
	2	0.27	17,00
	3	0.27	18,00
Hydro	1	0,02	18,00
	2	0,03	19,00
	3	0,03	20,00
DFIG	1	0,06	17,00
	2	0,10	18,00
	3	0,10	19,00
Diesel	1	0,10	16,00
	2	0,20	17,00
	3	0,20	18,00
HV Network	1	2,00	21,00
	2	2,00	21,00
	3	2,00	21,00
Microgrid 1	1	0.05	15,00
Microgrid 2	1	0.05	15,00
Microgrid 3	1	0.05	15,00
Microgrid 4	1	0.05	15,00
Microgrid 5	1	0.05	15,00

The main results from the market settlement are presented in the figures and tables shown below.

Figure 6-53 and Figure 6-54 show the evolution of the cleared bids towards market settlement considering the "good-citizen" and the "ideal-citizen" policies, respectively. It can be observed that there were different closing prices for the market settlement concerning the microgrid policy used. In his case, the "ideal-citizen" policy corresponded to a lower price (19 €/Mvar.h in opposition to 21 €/Mvar.h for the "good-citizen" policy) for the DSO in order to ensure the required var demand.

The selected var bids per technology are presented in Figure 6-55, comparing the "good-citizen" and the "ideal-citizen" policies. As can be observed, considering the "ideal-citizen" policy, the microgrids are able to bid reactive power to the market and, consequently, there is no need to import reactive power from the upstream network.

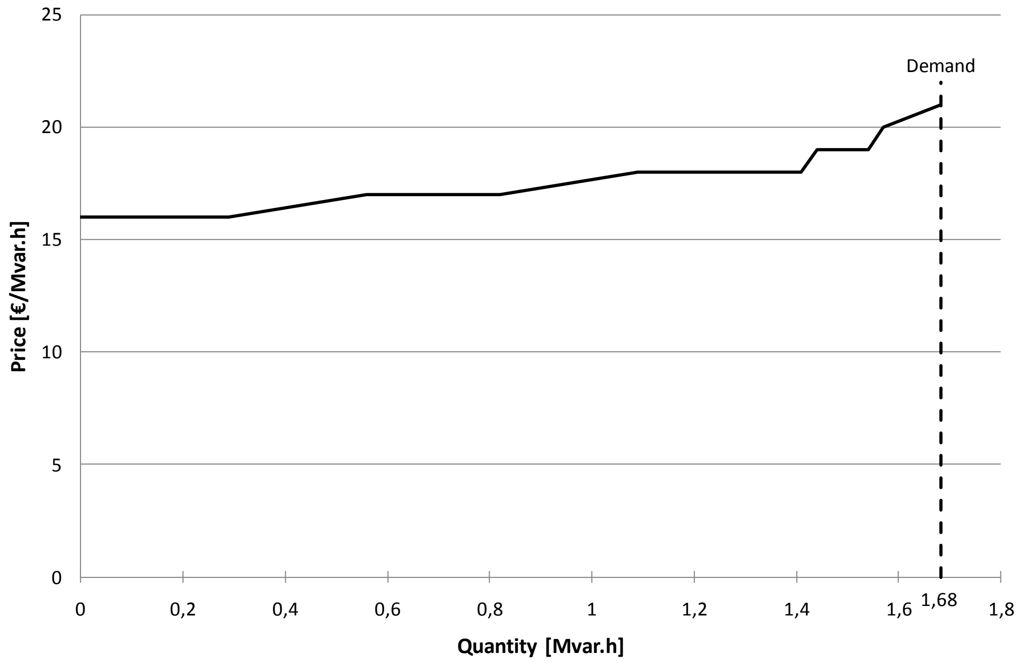

Figure 6-53 – Results from the Market Settlement (“Good-citizen” Policy) for the Peak Hour

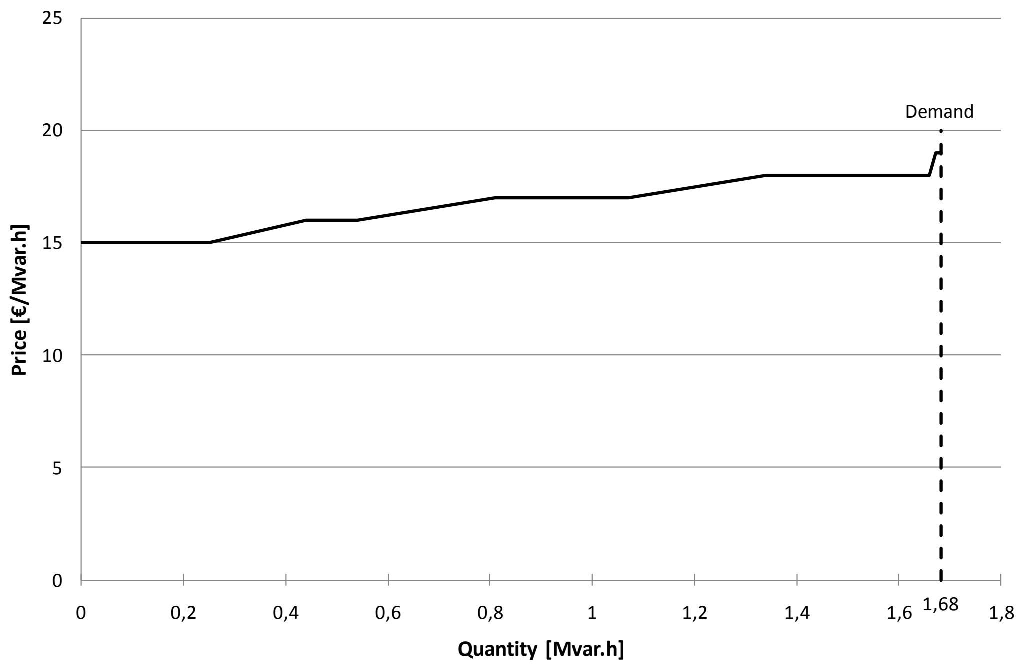

Figure 6-54 – Results from the Market Settlement (“Ideal-citizen” Policy) for the Peak Hour

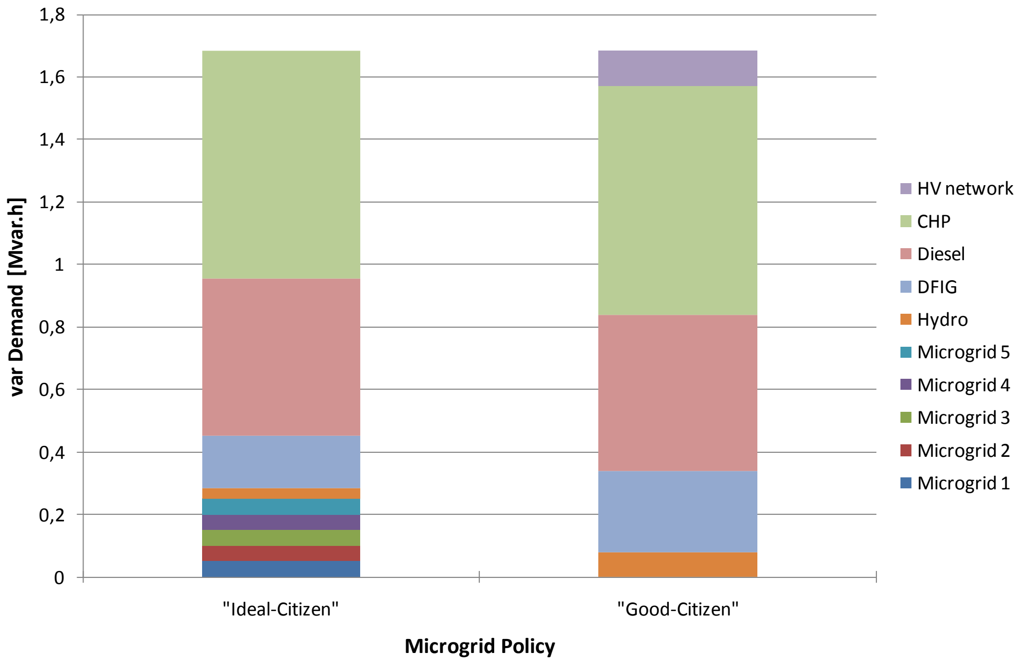

Figure 6-55 – Selected Bids ("Good-citizen" Policy vs. "Ideal-citizen" Policy) for the Peak Hour

Table 6-18 and Table 6-19 show the var bids and prices after the market settlement considering the "good-citizen" and the "ideal-citizen" policies, respectively.

Table 6-18 – Bids and Prices ("Good-citizen") for the Peak Hour

Generation Unit	Q [Mvar]	Price [€/Mvar.h]	Cost [€]
CHP	0,730	21,00	15,330
Hydro	0,080	21,00	1,680
DFIG	0,260	21,00	5,460
Diesel	0,500	21,00	10,500
HV Network	0,114	21,00	2,384
Total	**1,684**	**–**	**35,354**

Table 6-19 – Bids and Prices ("Ideal-citizen") for the Peak Hour

Generation Unit	Q [Mvar]	Price [€/Mvar.h]	Cost [€]
CHP	0,730	19,00	13,870
Hydro	0,033	19,00	0,628
DFIG	0,170	19,00	3,237
Diesel	0,500	19,00	9,500
Microgrid 1	0,05	19,00	0,950
Microgrid 2	0,05	19,00	0,950
Microgrid 3	0,05	19,00	0,950
Microgrid 4	0,05	19,00	0,950
Microgrid 5	0,05	19,00	0,950
Total	**1,683**	**–**	**31,984**

It can be seen that there is a small advantage in terms of costs for the DSO, given the reactive power bids submitted by the DG units and microgrids, which have lower values.

A summary of the results obtained from the OPF-like algorithm is presented in Table 6-20.

Table 6-20 – Results from the OPF-like algorithm for the Peak Hour

Maximum Voltage [p.u.]	Minimum Voltage [p.u.]	Active Energy Losses [MW.h]	Reactive Energy Losses [Mvar.h]
1,050	1,045	0,004	0,010

6.5 Summary and Main Conclusions

In this chapter, the performance of the voltage support tool (presented in Chapter 4) and the performance of the ancillary services market simulator for voltage control (presented in Chapter 5) have been evaluated.

In order to assess the behaviour of these algorithms, several distribution networks have been used: two MV networks and three LV networks. These networks are based on real distribution networks (except one MV test network – but real data is used) and include DG units (at the MV level) and microgeneration units (at the LV level).

First of all, concerning the voltage support tool, the performance of the ANNs that were used to replace the “active” LV networks was analysed. It was shown that the steady-state behaviour of these networks can be effectively reproduced by an ANN model with the architecture proposed in Chapter 4. It was also verified that the inclusion of these black-box models was able to significantly reduce computational time for the voltage support tool. The representation of “active” LV networks can be more accurate if a model for each feeder is used, given the possible imbalances between feeders in terms of load and generation. It was seen that this solution is able reduce the amount of microgeneration required in order to avoid overvoltages.

Furthermore, the optimization algorithm proposed (based on a meta-heuristic approach) that was adopted in order to deal with the voltage control problem in distribution systems has proved to be efficient in achieving the main objective function (minimize active power losses and minimize microgeneration curtailment) without violating the main technical and operational constraints, namely regarding voltage limits. From this procedure, several set-points are identified and sent to individual local controllers such as MGCCs, which are in charge of the “active” LV networks, MV-connected DG units and OLTC transformers.

In conclusion, the combination of the meta-heuristic optimization engine with an ANN equivalent representation of “active” LV networks allows is able to model adequately the distribution system, thus enabling the use of this approach for real-time under DMS environments.

Concerning the ancillary services market simulator for voltage control, a market approach based on reactive power use has been developed that is able to incorporate bids from several different agents (DG located at the MV level, microgrids, etc.) and distribute var between the all ancillary services providers in order to minimize the total cost to the DSO. Two different scenarios have been presented for illustrating the performance of the var market simulator: peak hour and valley hour.

Moreover, two policies for microgrid participation were modelled: “good-citizen” and “ideal-citizen”. It was seen that the “ideal-citizen” policy for microgrids is able to increase efficiency by avoiding the need for importing reactive power from the upstream HV network and take full profit of the resources available locally (MV-connected DG and microgrids). Furthermore, as it was considered that importing var from the HV network is more expensive, this policy was able to reduce the total costs to the DSO in the peak hour scenario.

"I have come to believe that the whole world is an enigma, a harmless enigma that is made terrible by our own mad attempt to interpret it as though it had an underlying truth."

Umberto Eco (b. 1932)

Chapter 7 – Conclusion

In this chapter, the main contributions of this thesis for the overall coordinated and optimized management of distribution networks with a massive penetration of DG and microgrids are clearly identified. Furthermore, the perspectives for future work to be developed are envisaged, especially regarding the algorithm developed for coordinated voltage support (presented in Chapter 4) and the conceptual framework ancillary services markets for voltage control (presented in Chapter 5).

7.1 Main Contributions of the Thesis

The advent of DER in distribution networks is fundamentally altering the paradigm concerning power system operation. In particular, large scale deployment of DG sources, especially the ones based on RES, can pose several technical, economical and regulatory challenges (as seen in Chapter 1) that must be efficiently tackled in order to fully integrate these resources in the distribution system.

Rising to these challenges, the main concern of the work implied in this thesis was the development of concepts and methodologies capable of supporting the coordinated and optimized management of future distributions networks with large scale integration of DG at the MV level and microgeneration at the LV level. In order to achieve large scale integration of this type of units a new operational philosophy is required that goes way beyond the traditional "fit-and-forget" policy used in the early days of the DG paradigm.

The work developed here is related to a new operational paradigm for "active" distribution networks, based on the development and extension of the microgrid concept as previously defined. According to this concept, a microgrid can be regarded as an active cell of the distribution system that can be fully involved in network operation.

The integration of multiple DG units and microgrids in the distribution system, together with dispersed storage devices and controllable loads, leads to the definition of a new higher order structure formed at the MV level: **the multi-microgrid**. In order to be able to manage efficiently all these DER, a hierarchical control architecture is proposed that includes an additional control level. This new control level is headed by the CAMC, a controller located at the HV/MV substation, which will be in charge of the whole MV distribution network. Furthermore, control functionalities that were originally performed by the central DMS need now to be adapted to this concept and additional functionalities must be developed.

A control architecture such as the one proposed must rely on an efficient communication scheme that can be based on a smart metering infrastructure. In fact, it is believed that the deployment of a smart metering infrastructure will be vital in order to fully implement advanced control and management functionalities, paving the way for the implementation of the smartgrid concept.

The development of a hierarchical control architecture such as the one proposed in Chapter 3 is essential in order to be able to manage the several DER in a coordinated and efficient way, thus maximizing the integration of DG and microgeneration. Current distribution systems are able to accommodate these resources without requiring any special measures, considering low and moderate penetration scenarios for DG and microgeneration. However, in order to achieve massive DG and microgeneration penetration levels (especially for technologies based on RES), several technical challenges arise especially in terms of network operation, which requires the development of specific control and management tools. In this context, voltage control emerges as a vital issue that must be addressed.

Consequently, the main contributions of this thesis are thought to be:

- The **definition of a distributed control architecture** for distribution systems in order to integrate efficiently the several DER such as DG units, controllable loads and storage devices, particularly at the MV and LV levels (Chapter 3);
- The **proposal of an ancillary services market for voltage control**, mainly at a conceptual level, based on technical and economic criteria, integrating all DER available at the MV level (Chapter 5);
- The **demonstration of the possible contribution from microgrids as aggregators of DER** at the LV level for ancillary services markets, that otherwise would not be able to participate (Chapter 5);
- The **development of an ANN model able to emulate the steady-state behaviour of microgrids** or "active" LV feeders to be included in the voltage control algorithm (Chapter 4);
- The **development of a multi-objective algorithm for voltage control integrating the MV and LV levels**, by exploiting DER in a coordinated way in order to support distribution network operation (Chapter 4).

In conclusion, the work presented in this thesis focused on the development of innovative control and management strategies and algorithms for dealing with large scale integration of DG at the MV level and microgeneration at the LV level in order to integrate efficiently these new DER in the distribution system. This required the development of solutions for the voltage control problem in the context of future distribution systems, namely a methodology designed to integrate a tool able to support network operation and a proposal for an ancillary services market for voltage control. The solutions developed were implemented and tested in a MATLAB© simulation environment with good results.

It must be noted that the approaches developed in this thesis were designed exclusively for normal interconnected operation of the multi-microgrid system. In fact, dealing with emergency operation (particularly islanding and islanded operation) requires an altogether different approach since the main priority in this situation is not the optimization of operation conditions or the fulfilment of any economical criteria but rather the survival of the MV system itself.

7.2 Future Perspectives

First of all, given the fact that most of the work presented in this thesis was developed under the framework of the European project More Microgrids, it must be understood that the main research line was *ab initio* somewhat conditioned and oriented, which brought many important advantages together with some mild drawbacks.

In the course of the present work, several issues have arisen that, for one reason or the other, were not fully addressed in this thesis. The options that had to be made along the way were assumed based on the direction intended for the research work, trying not to drift away from the main ultimate focus and, of course, taking into account the inherent time constraints of this thesis. However, some of these issues can be particularly relevant to the subject under analysis and therefore may contribute to further improve the methodologies that have been presented in this thesis. Some suggested developments for the work developed are detailed in the paragraphs below.

In this thesis, the problem of voltage control was addressed from a steady-state perspective (*i.e.* under stationary conditions). Nevertheless, it would also be convenient to assess the dynamic behaviour of DG and microgeneration units regarding voltage control. In this case, specific models for these units, including the specific characteristics of the technology used, have to be developed. This suggestion comes also from the development of other PhD theses, namely one by Nuno Gil [126] regarding coordinated frequency support in dynamic regime, that have been recently published.

Furthermore, the use of a decentralized control architecture such as the one proposed here may be suitable for exploiting decentralized computing techniques such as intelligent agents. In fact, several applications of MAS to electrical power systems are being developed right now for implementing control algorithms and simulating market structures. It is believed that such a technological approach could be implemented with good results for the issues addressed in this thesis, under essentially the same underlying principles.

Another major improvement that can be anticipated regarding the voltage support tool presented in Chapter 4 is the possibility of avoiding the spillage of excess generation from microsources that is necessary in order to maintain voltage profiles within admissible limits. This can be achieved by including dispersed storage devices in the LV network in order to be able to store the excess energy from microgeneration units based on RES such as PV panels, especially in situations of low energy consumption. Consequently, it will be possible to utilize this stored energy during peak demand hours, thus contributing to “smoother” generation profiles and increased global efficiency.

Two main issues must be taken into account when addressing the possibility of including dispersed storage solutions in distribution networks:

- **Siting** – the location of the devices in the LV network must be carefully planned in order to select efficiently the most adequate sites to maximize the energy to be stored.
- **Sizing** – the definition of the "size" of the storage devices is critical, particularly in face of the adequate power *vs.* energy characteristics for the technology to be used for storage.

Several technologies may be employed such as flywheels, super capacitors, vanadium fuel cells or batteries. Each technology has its own advantages and drawbacks, particularly in terms of power capacity and energy that can be supplied. Moreover, with the foreseen integration of electric vehicles in the distribution system it is expected that these units may participate in network operation not only by providing energy but also ancillary services following a vehicle-to-grid (V2G) approach. A fleet of electric vehicles can then be regarded as dispersed storage unit that may contribute to voltage control, even if only using a local control strategy.

Concerning the optimization algorithm to be used in the voltage control algorithm which was developed, it may be interesting to try out other optimization approaches that may prove to be more suitable than the one used in this thesis. Namely, the use of methods based on Pareto multi-objective optimization can be a good choice for the voltage control algorithm since they are able to adapt meta-heuristic algorithms (such as EPSO, used in this case) to solving multi-objective problems. Such an approach would facilitate the inclusion of other objectives based, for instance, on economic criteria. For solving problems with multiple conflicting objectives, creating a single optimization function (as was done in this thesis) may become no longer acceptable since the decision-maker may wish to know all possible efficient solutions concerning all objectives – a type of trade-off analysis. These methods that concurrently optimize the different objectives allow defining the Pareto front and offers solutions consisting of a set of trade-offs.

For the ANN model used for replacing the "active" LV networks, it is believed that it may be possible to further improve the approach presented by developing single-phase models of the LV feeders to include in the voltage control algorithm. This will enable the use of more accurate models that can contribute to reduce the amount of microgeneration shedding required for maintaining the voltage profiles within admissible limits, especially in the case of LV networks with high voltage imbalances. This option may, however, require longer simulation times so that a compromise between the complexity of the model and the performance of the algorithm must be achieved.

Concerning ancillary services markets for voltage control, a long-term market for reactive power capacity may also be implemented, similar to proposals designed for the transmission system. This will allow the owners of reactive power compensation devices to see their investment costs recovered.

Since reactive power and voltage control are predominantly local requirements, a market for reactive power should be regarded as a local/regional market, rather than a system-wide market. Therefore, the definition of voltage-control areas may support the development of localized competitive markets for reactive power. These areas may be defined using concepts such as electrical distance, similarly to what is done at the transmission level.

Furthermore, one improvement that can be made to the ancillary services market proposal presented in this thesis is to model price-sensitive loads. In the work presented in this thesis, demand is regarded as inelastic. By considering elasticity in the demand, it will be possible to disconnect some non-essential loads especially when market prices are high.

In addition, there is also the possibility of having bilateral contracts that co-exist with the market mechanism. This requires the modelling of an additional constraint ensuring that the bilateral transactions are within pre-specified limits.

Regarding the OPF-like approach used for the ancillary services market simulator, it may be interesting to use a different type of algorithm such as a security-constrained OPF. This type of OPF allows assessing the operation of the system considering not only normal operating conditions but also violations following contingencies. This would require defining a new objective function including the operating cost of the system and identifying the main contingencies that can affect the system. The algorithm would then be able to change the system pre-contingency operating point so that the total cost is minimized, and at the same time no security limit is violated if any contingency occurs.

Finally, on a more general note, it is assumed that a detailed and thorough analysis of technical specifications related to control requirements and particularly communication requirements is crucial in order to be able to implement this type of strategies.

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Appendix A – Power Flow in Four-Wire Distribution Networks

In the three-phase power flow algorithm, each node or line section in the network is numbered by a single index, regardless of the number of phases of this node or line section. Figure A-1 represents the line section between nodes i and j with shunt admittances and loads attached to the nodes.

Based on Figure A-1, a 5 x 5 matrix can represent the series impedance Z_l of the line section l.

$$Z_l = \begin{bmatrix} Z_{aa} & Z_{ab} & Z_{ac} & Z_{an} & Z_{ag} \\ Z_{ab} & Z_{bb} & Z_{bc} & Z_{bn} & Z_{bg} \\ Z_{ac} & Z_{bc} & Z_{cc} & Z_{cn} & Z_{cg} \\ Z_{an} & Z_{bn} & Z_{cn} & Z_{nn} & Z_{ng} \\ Z_{ag} & Z_{bg} & Z_{cg} & Z_{ng} & Z_{gg} \end{bmatrix} \quad \text{(A-1)}$$

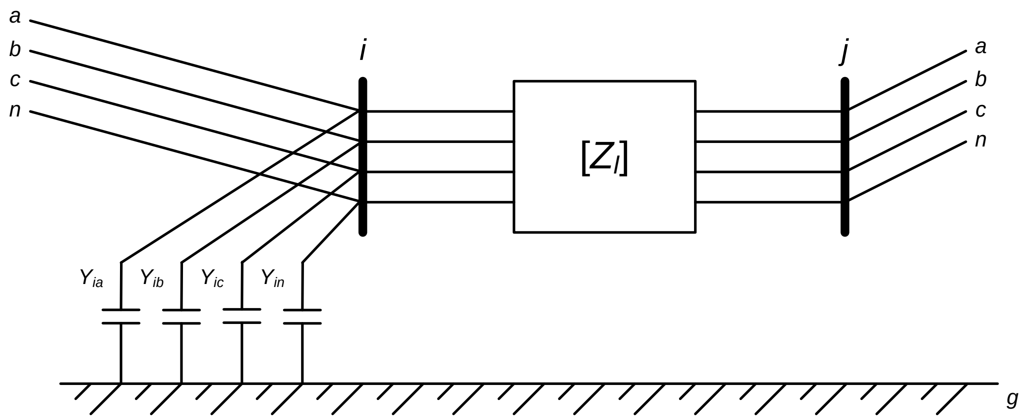

Figure A-1 – Three-phase Four-wire Line Section (adapted from [125])

Where

a, b, c are the phase lines
n is the neutral wire
g is the ground

If any phase, neutral wire, or grounding of the line section does not exist, the corresponding row and column in this matrix will all contain zero entries. The shunt capacitance part of LV lines can be neglected. Branches are numbered according to the procedure described in [124].

The model of a three-phase four-wire multi-grounded distribution line is shown in Figure A-2.

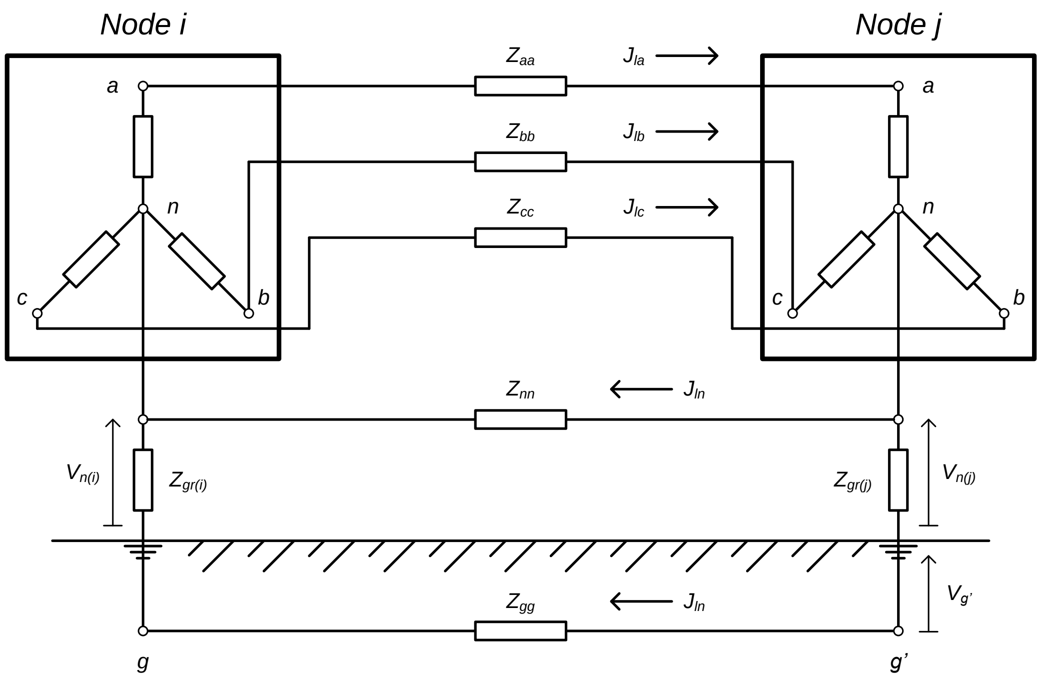

Figure A-2 – Model of the Three-phase Four-wire Multi-grounded Distribution Line (adapted from [125])

Assuming that the root node is the slack node with known voltage magnitude and angle, this iterative procedure consists of three simple steps [125].

At iteration k:

Step 1 – Nodal current calculation

$$\begin{bmatrix} \mathrm{I_{ia}} \\ \mathrm{I_{ib}} \\ \mathrm{I_{ic}} \\ \mathrm{I_{in}} \\ \mathrm{I_{ig}} \end{bmatrix} = \begin{bmatrix} \left(\dfrac{\mathrm{S_{ia}}}{\mathrm{V_{ia}}}\right)^{(\mathrm{k}-1)^*} \\ \left(\dfrac{\mathrm{S_{ib}}}{\mathrm{V_{ib}}}\right)^{(\mathrm{k}-1)^*} \\ \left(\dfrac{\mathrm{S_{ic}}}{\mathrm{V_{ic}}}\right)^{(\mathrm{k}-1)^*} \\ -\dfrac{\mathrm{Z_{gi}}}{\mathrm{Z_{nni}} + \mathrm{Z_{gi}}} \cdot \left(\mathrm{I_{ia}^{(k)}} + \mathrm{I_{ib}^{(k)}} + \mathrm{I_{ic}^{(k)}}\right) \\ -\dfrac{\mathrm{Z_{nni}}}{\mathrm{Z_{nni}} + \mathrm{Z_{gi}}} \cdot \left(\mathrm{I_{ia}^{(k)}} + \mathrm{I_{ib}^{(k)}} + \mathrm{I_{ic}^{(k)}}\right) \end{bmatrix} - \begin{bmatrix} \mathrm{Y_{ia}} & & & & \\ & \mathrm{Y_{ib}} & & & \\ & & \mathrm{Y_{ic}} & & \\ & & & \mathrm{Y_{in}} & \\ & & & & 0 \end{bmatrix} \cdot \begin{bmatrix} \mathrm{V_{ia}} \\ \mathrm{V_{ib}} \\ \mathrm{V_{ic}} \\ \mathrm{V_{in}} \\ \mathrm{V_{ig}} \end{bmatrix}^{(\mathrm{k}-1)} \qquad \textbf{(A-2)}$$

Where

$I_{ia}, I_{\mathrm{ib}}, I_{ic}, I_{in}, I_{ig}$	are the current injections at node i
$S_{ia}, S_{ib}, S_{ic}, S_{in}, S_{ig}$	are the scheduled (known) power injections at node i
$V_{ia}, V_{ib}, V_{ic}, V_{in}, V_{ig}$	are the voltages at node i
$Y_{ia}, Y_{ib}, Y_{ic}, Y_{in}, Y_{ig}$	are the admittances of all shunt elements at node i
Z_{gri}	is the grounding impedance at node i $\left(Z_{gi} = Z_{gri} + Z_{ggi}\right)$

Step 2 – Backward sweep – Section current calculation

Starting from the line section in the last layer and moving toward the root node, the current in line section l is given by:

$$\begin{bmatrix} J_{la} \\ J_{lb} \\ J_{lc} \\ J_{ln} \\ J_{lg} \end{bmatrix}^{(k)} = -\begin{bmatrix} I_{ja} \\ I_{jb} \\ I_{jc} \\ I_{jn} \\ I_{jg} \end{bmatrix}^{(k)} + \sum_{m \in M} \begin{bmatrix} J_{ma} \\ J_{mb} \\ J_{mc} \\ J_{mn} \\ J_{mg} \end{bmatrix}^{(k)} \tag{A-3}$$

Where

$J_{la}, J_{lb}, J_{lc}, J_{ln}, J_{lg}$	are the current flows on line section l
M	is the set of line sections connected downstream to node j

Step 3 – Forward sweep – Nodal voltage calculation

Starting from the first layer and moving toward the last layer, the voltage at node j is given by:

$$\begin{bmatrix} V_{ja} \\ V_{jb} \\ V_{jc} \\ V_{jn} \\ V_{jg} \end{bmatrix}^{(k)} = \begin{bmatrix} V_{ia} \\ V_{ib} \\ V_{ic} \\ V_{in} \\ V_{ig} \end{bmatrix}^{(k)} - \begin{bmatrix} Z_{aa} & Z_{ab} & Z_{ac} & Z_{an} & Z_{ag} \\ Z_{ab} & Z_{bb} & Z_{bc} & Z_{bn} & Z_{bg} \\ Z_{ac} & Z_{bc} & Z_{cc} & Z_{cn} & Z_{cg} \\ Z_{an} & Z_{bn} & Z_{cn} & Z_{nn} & Z_{ng} \\ Z_{ag} & Z_{bg} & Z_{cg} & Z_{ng} & Z_{gg} \end{bmatrix} \cdot \begin{bmatrix} J_{la} \\ J_{lb} \\ J_{lc} \\ J_{ln} \\ J_{lg} \end{bmatrix}^{(k)} \tag{A-4}$$

Voltage correction in the nodes with grounded neutral and downstream nodes should be performed. Voltage in the nodes with neutral grounded at iteration k is as follows:

$$V_{in}^{(k)} = Z_{gri} \cdot J_{lg}^{(k)}, i \in \{Grounded\ nodes\} \tag{A-5}$$

Concerning the convergence criteria, after these steps are executed in each iteration, the power mismatches at each node for all phases are calculated as follows:

$$\Delta S_{ia}^{(k)} = V_{ia}^{(k)} \cdot \left(I_{ia}^{(k)}\right)^* - Y_{ia}^* \cdot \left|V_{ia}^{(k)}\right|^2 - S_{ia} \tag{A-6}$$

$$\Delta S_{ib}^{(k)} = V_{ib}^{(k)} \cdot \left(I_{ib}^{(k)}\right)^* - Y_{ib}^* \cdot \left|V_{ib}^{(k)}\right|^2 - S_{ib} \tag{A-7}$$

$$\Delta S_{ic}^{(k)} = V_{ic}^{(k)} \cdot \left(I_{ic}^{(k)}\right)^* - Y_{ic}^* \cdot \left|V_{ic}^{(k)}\right|^2 - S_{ic} \tag{A-8}$$

$$\Delta S_{in}^{(k)} = V_{in}^{(k)} \cdot \left(I_{in}^{(k)}\right)^{*} - Y_{in}^{*} \cdot \left|V_{in}^{(k)}\right|^{2} \tag{A-9}$$

$$\Delta S_{ig}^{(k)} = V_{ig}^{(k)} \cdot \left(I_{ig}^{(k)}\right)^{*} \tag{A-10}$$

If the real or imaginary part of any of the power mismatches is greater than a given convergence criterion, steps 1-3 are repeated until convergence is achieved.

The initial voltage for all nodes should be equal to the root node voltage (flat start) as follows:

$$\begin{bmatrix} V_{ia} \\ V_{ib} \\ V_{ic} \\ V_{in} \\ V_{ig} \end{bmatrix}^{(0)} = \begin{bmatrix} V_{ref} \\ a^2 \cdot V_{ref} \\ a^2 \cdot V_{ref} \\ 0 \\ 0 \end{bmatrix}, a = e^{j\frac{2\pi}{3}} \tag{A-11}$$

Equations for calculation of the impedance matrix in a 5 x 5 representation are given in [125].

Note that in this work the shunt capacitances of the lines were neglected since this method will be employed in a LV network. Also, the grounding was not considered, thus the corresponding row and column in the matrix Z_l all contained zero entries.

Appendix B – Test Network Data

In this appendix, the full data concerning all test networks presented in Chapter 6 is given. In particular, transformer and branch data, as well as load and generation data are provided for the two MV network and the three LV networks used in this thesis.

B-1 Medium Voltage Network 1

As previously seen, MV Network 1 is a real Portuguese distribution network from a typical rural area. The scheme of this network is presented in Figure B-1.

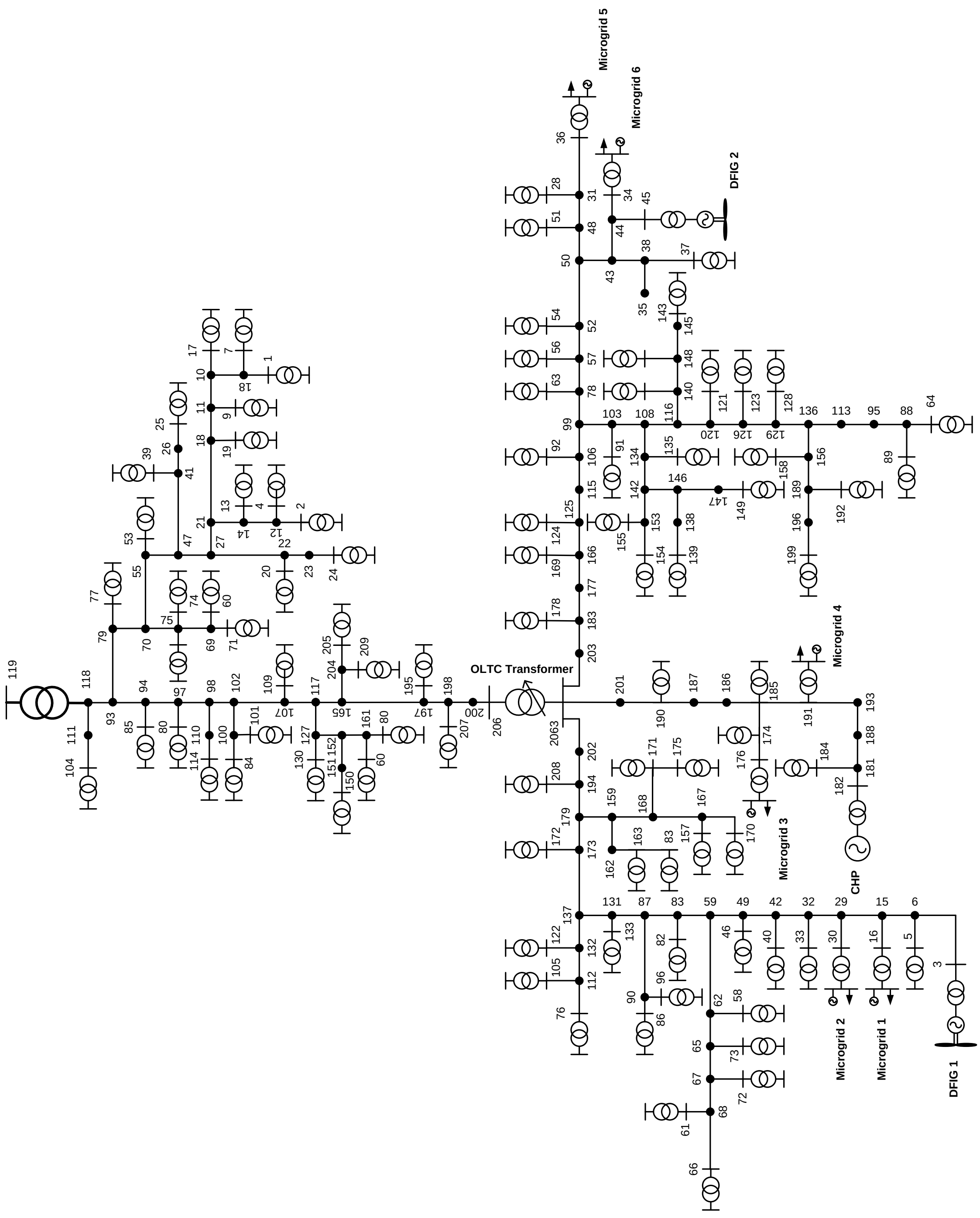

Figure B-1 – MV Network 1

The line data for this network is presented in Table B-1.

Table B-1 – Line Data for MV Network 1

Branch Number	From Bus	To Bus	Resistance [Ω]	Reactance [Ω]	Shunt Susceptance [Ω]
1	1	8	0,2047	0,1103	7,0E-05
2	2	12	0,1268	0,0683	4,0E-05
3	3	6	0,1415	0,0763	0,0E+00
4	4	12	0,1814	0,0978	6,0E-05
5	5	6	0,2068	0,0699	0,0E+00
6	6	15	0,2170	0,1984	1,0E-05
7	7	8	0,0055	0,0019	0,0E+00
8	8	10	0,0676	0,0228	1,0E-05
9	9	11	0,0553	0,0298	2,0E-05
10	10	11	0,0396	0,0134	1,0E-05
11	10	17	0,0518	0,0279	2,0E-05
12	11	18	0,1462	0,0494	3,0E-05
13	12	14	0,0268	0,0145	1,0E-05
14	13	14	0,0013	0,0004	0,0E+00
15	14	21	0,0794	0,0428	3,0E-05
16	15	16	0,0068	0,0037	0,0E+00
17	15	29	0,4408	0,4030	2,0E-05
18	18	19	0,0750	0,0405	2,0E-05
19	18	21	0,0780	0,0263	2,0E-05
20	20	22	0,0416	0,0177	1,0E-05
21	21	27	0,1462	0,0494	3,0E-05
22	22	23	0,1090	0,0277	2,0E-05
23	22	27	0,1424	0,0606	4,0E-05
24	23	24	0,0963	0,0245	1,0E-05
25	25	26	0,0001	0,0000	0,0E+00
26	26	41	0,2183	0,1177	7,0E-05
27	27	47	0,3495	0,1487	9,0E-05
28	28	31	0,1930	0,1040	0,0E+00
29	29	30	0,1049	0,0566	0,0E+00
30	29	32	0,0948	0,0866	0,0E+00
31	31	36	0,3823	0,2061	1,0E-05
32	31	48	1,1241	0,6059	2,0E-05
33	32	33	0,0835	0,0450	0,0E+00
34	32	42	0,1740	0,1591	1,0E-05
35	34	44	0,2061	0,1111	0,0E+00
36	35	38	0,0448	0,0242	0,0E+00
37	37	38	0,1453	0,0362	0,0E+00
38	38	43	0,1039	0,0560	0,0E+00
39	39	41	0,0314	0,0080	0,0E+00
40	40	42	0,0039	0,0021	0,0E+00
41	41	47	0,2609	0,0664	4,0E-05
42	42	49	0,4222	0,3860	2,0E-05
43	43	44	0,3860	0,1304	0,0E+00
44	43	50	0,4990	0,2690	1,0E-05
45	44	45	0,3469	0,1172	0,0E+00
46	46	49	0,2259	0,1218	0,0E+00
47	47	55	0,2067	0,0880	5,0E-05
48	48	50	0,5840	0,3148	1,0E-05
49	48	51	0,2461	0,1327	0,0E+00

Branch Number	From Bus	To Bus	Resistance [Ω]	Reactance [Ω]	Shunt Susceptance [Ω]
50	49	59	0,3764	0,3441	1,0E-05
51	50	52	0,0663	0,0357	0,0E+00
52	52	54	0,1428	0,0482	0,0E+00
53	52	57	0,2855	0,1539	1,0E-05
54	53	55	0,0988	0,0533	3,0E-05
55	55	70	0,1623	0,0691	4,0E-05
56	56	57	0,2525	0,0853	0,0E+00
57	57	78	0,4794	0,2584	1,0E-05
58	58	62	0,1962	0,1058	0,0E+00
59	59	62	0,1475	0,0795	0,0E+00
60	59	83	0,2648	0,2421	1,0E-05
61	60	69	0,0997	0,0537	3,0E-05
62	61	68	0,1803	0,0972	0,0E+00
63	62	65	0,1788	0,0964	0,0E+00
64	63	78	1,0034	0,2554	1,0E-05
65	64	88	0,5042	0,2718	1,0E-05
66	65	67	0,1230	0,0663	0,0E+00
67	65	73	0,2771	0,0936	0,0E+00
68	66	68	0,2173	0,1171	0,0E+00
69	67	68	0,0570	0,0307	0,0E+00
70	67	72	0,0789	0,0426	0,0E+00
71	69	71	0,0067	0,0036	0,0E+00
72	69	75	0,0688	0,0371	2,0E-05
73	70	75	0,0379	0,0204	1,0E-05
74	70	79	0,0618	0,0263	2,0E-05
75	74	75	0,0176	0,0095	1,0E-05
76	75	81	0,0324	0,0175	1,0E-05
77	76	112	1,6337	0,4159	1,0E-05
78	77	79	0,0037	0,0020	0,0E+00
79	78	99	0,4483	0,2416	1,0E-05
80	79	93	0,1407	0,0599	4,0E-05
81	80	97	0,0866	0,0467	3,0E-05
82	82	83	0,5953	0,3209	1,0E-05
83	83	87	0,0980	0,0896	0,0E+00
84	84	100	0,0817	0,0440	3,0E-05
85	85	94	0,0577	0,0311	2,0E-05
86	86	90	0,0528	0,0285	0,0E+00
87	87	90	0,1284	0,0692	0,0E+00
88	87	131	0,6507	0,5949	2,0E-05
89	88	89	0,0041	0,0022	0,0E+00
90	88	95	0,1258	0,0678	0,0E+00
91	90	96	0,2214	0,1194	0,0E+00
92	91	103	0,4638	0,1181	0,0E+00
93	92	106	0,5553	0,1876	1,0E-05
94	93	94	0,0681	0,0501	3,0E-05
95	93	118	0,2905	0,2138	1,3E-04
96	94	97	0,0637	0,0469	3,0E-05
97	95	113	0,3209	0,1730	1,0E-05
98	97	98	0,0035	0,0026	0,0E+00
99	98	102	0,1530	0,1126	7,0E-05
100	98	110	0,0891	0,0379	2,0E-05
101	99	103	0,4853	0,2616	1,0E-05
102	99	106	0,2313	0,1247	0,0E+00

Branch Number	From Bus	To Bus	Resistance [Ω]	Reactance [Ω]	Shunt Susceptance [Ω]
103	100	101	0,0014	0,0005	0,0E+00
104	100	102	0,0083	0,0045	0,0E+00
105	102	107	0,0486	0,0357	2,0E-05
106	103	108	0,3099	0,1671	1,0E-05
107	104	111	0,0171	0,0062	2,3E-04
108	105	112	0,2902	0,0739	0,0E+00
109	106	115	0,3037	0,1637	1,0E-05
110	107	109	0,0013	0,0004	0,0E+00
111	107	117	0,0880	0,0648	4,0E-05
112	108	116	0,8409	0,4533	2,0E-05
113	108	134	1,2249	0,3118	1,0E-05
114	110	114	0,0001	0,0001	0,0E+00
115	111	118	0,0754	0,0321	2,0E-05
116	112	132	1,3514	0,3440	1,0E-05
117	113	136	1,0006	0,5394	2,0E-05
118	115	125	0,4096	0,2208	1,0E-05
119	116	120	0,5514	0,2972	1,0E-05
120	116	140	0,8183	0,2764	1,0E-05
121	117	127	0,0978	0,0330	2,0E-05
122	117	165	0,2989	0,2200	1,4E-04
123	118	119	0,0487	0,0359	2,0E-05
124	120	121	0,0064	0,0016	0,0E+00
125	120	126	0,2964	0,1598	1,0E-05
126	122	132	0,2456	0,1324	0,0E+00
127	123	126	0,0543	0,0292	0,0E+00
128	124	125	0,0158	0,0053	0,0E+00
129	125	166	0,7455	0,4019	1,0E-05
130	126	129	0,3266	0,0831	0,0E+00
131	127	130	0,0226	0,0076	0,0E+00
132	127	152	0,1983	0,0670	4,0E-05
133	128	129	0,1443	0,0488	0,0E+00
134	129	136	0,1918	0,0488	0,0E+00
135	131	133	0,0088	0,0048	0,0E+00
136	131	137	0,1223	0,1119	0,0E+00
137	132	137	0,3695	0,0941	0,0E+00
138	134	135	0,0625	0,0211	0,0E+00
139	134	142	0,3531	0,0899	0,0E+00
140	136	156	0,9744	0,2480	1,0E-05
141	137	173	0,6280	0,5741	2,0E-05
142	138	139	0,0088	0,0017	1,0E-05
143	138	146	0,2060	0,1110	0,0E+00
144	140	148	0,2126	0,0718	0,0E+00
145	140	154	0,4309	0,1456	1,0E-05
146	141	148	0,1800	0,0608	0,0E+00
147	142	146	0,1286	0,0328	0,0E+00
148	142	153	0,3278	0,1767	1,0E-05
149	143	145	0,0333	0,0112	0,0E+00
150	144	162	0,7668	0,1952	1,0E-05
151	145	148	0,0318	0,0108	0,0E+00
152	146	147	0,0486	0,0124	0,0E+00
153	147	149	0,0065	0,0037	0,0E+00
154	150	151	0,0040	0,0009	3,0E-05
155	151	152	0,0303	0,0102	1,0E-05

Branch Number	From Bus	To Bus	Resistance [Ω]	Reactance [Ω]	Shunt Susceptance [Ω]
156	152	161	0,0703	0,0238	1,0E-05
157	153	155	0,1286	0,0434	0,0E+00
158	153	164	0,2271	0,1224	0,0E+00
159	156	158	0,4256	0,2294	1,0E-05
160	156	189	1,1513	0,2931	1,0E-05
161	157	167	0,2284	0,1231	0,0E+00
162	159	162	0,0523	0,0282	0,0E+00
163	159	168	0,2601	0,0662	0,0E+00
164	159	179	0,3629	0,1956	1,0E-05
165	160	161	0,0013	0,0004	0,0E+00
166	161	180	0,1066	0,0360	2,0E-05
167	162	163	0,0341	0,0184	0,0E+00
168	165	197	0,1210	0,0891	6,0E-05
169	165	204	0,1680	0,0906	5,0E-05
170	166	169	0,0200	0,0067	0,0E+00
171	166	177	0,1472	0,0793	0,0E+00
172	167	168	0,2711	0,0916	0,0E+00
173	167	170	0,0296	0,0100	0,0E+00
174	168	171	0,2323	0,0591	0,0E+00
175	171	175	0,0585	0,0103	4,0E-05
176	172	173	0,0714	0,0241	0,0E+00
177	173	179	0,0665	0,0608	0,0E+00
178	174	176	0,0706	0,0221	9,0E-05
179	174	185	0,1267	0,0262	8,0E-05
180	175	176	0,0130	0,0041	2,0E-05
181	176	182	0,0730	0,0128	5,0E-05
182	177	183	0,0634	0,0342	0,0E+00
183	178	183	0,0336	0,0114	0,0E+00
184	179	194	0,1142	0,1044	0,0E+00
185	181	184	0,0222	0,0070	3,0E-05
186	181	188	0,0931	0,0083	2,0E-05
187	182	184	0,0341	0,0107	4,0E-05
188	183	203	0,6081	0,3278	1,0E-05
189	185	186	0,0193	0,0043	2,0E-05
190	185	191	0,0631	0,0123	4,0E-05
191	186	187	0,0032	0,0007	0,0E+00
192	187	190	0,0377	0,0084	4,0E-05
193	188	193	0,1864	0,0242	8,0E-05
194	189	192	0,0715	0,0182	0,0E+00
195	189	196	0,2876	0,0972	0,0E+00
196	190	201	0,4383	0,2363	1,0E-05
197	191	193	0,0111	0,0025	1,0E-05
198	194	202	0,2091	0,1911	1,0E-05
199	194	208	0,9957	0,2481	1,0E-05
200	195	197	0,0008	0,0004	0,0E+00
201	196	199	0,1212	0,0235	7,0E-05
202	197	198	0,0056	0,0041	0,0E+00
203	198	200	0,0473	0,0348	2,0E-05
204	198	207	0,0989	0,0533	3,0E-05
205	200	2063	0,0386	0,0284	2,0E-05
206	201	206	0,0102	0,0032	1,0E-05
207	202	206	0,0098	0,0031	1,0E-05
208	203	206	0,0072	0,0023	1,0E-05

Branch Number	From Bus	To Bus	Resistance [Ω]	Reactance [Ω]	Shunt Susceptance [Ω]
209	204	205	0,0033	0,0018	0,0E+00
210	204	209	0,0498	0,0268	2,0E-05

The transformer data for this network is presented in Table B-2.

Table B-2 – Transformer Data for MV Network 1

Branch Number	From Bus	To Bus	Rated Power [MVA]	Primary Voltage [kV]	Secondary Voltage [kV]	Reactance [%]
1	206	2063	5	30	15	5,79

The load data for this network is presented in Table B-3.

Table B-3 – Load Data for MV Network 1

Bus Number	Load Installed Capacity [kVA]
1	100
2	100
3	160
4	100
5	160
7	100
9	100
13	100
16	100
17	50
19	100
20	1200
24	100
25	630
28	50
30	100
33	100
34	100
36	100
37	15
39	25
40	50
45	25
46	100
51	160
53	160
54	250
56	250
58	100
60	100
61	160
63	160
64	50
66	200
71	160

Bus Number	Load Installed Capacity [kVA]
72	50
73	100
74	160
76	100
77	50
80	100
81	250
82	100
84	50
85	100
86	25
89	100
91	100
92	250
96	75
101	50
104	0
105	100
109	100
114	1335
121	100
122	50
123	160
124	100
128	100
130	100
133	100
135	50
139	1000
141	50
143	500
144	100
149	500
150	630
154	100
155	0
157	100
158	100
160	100
163	100
164	100
169	50
170	200
171	100
172	100
174	400
175	160
176	630
178	50
180	100
182	125
184	400
185	250

Bus Number	Load Installed Capacity [kVA]
190	630
191	630
192	100
195	25
199	160
205	250
207	100
208	30
209	100

The generation data for this network is presented in Table B-4.

Table B-4 – Generation Data for MV Network 1

Bus Number	Generation Installed Capacity [MVA]
3	1
16	0,1
30	0,1
34	0,1
36	0,1
45	1
176	0,63
182	2
191	0,63

B-2 Medium Voltage Network 2

As previously seen, MV Network 2 is a test network using real data considering two distinct areas: an urban feeder on the left-hand side and a rural feeder on the right-hand side. The scheme of this network is presented in Figure B-2.

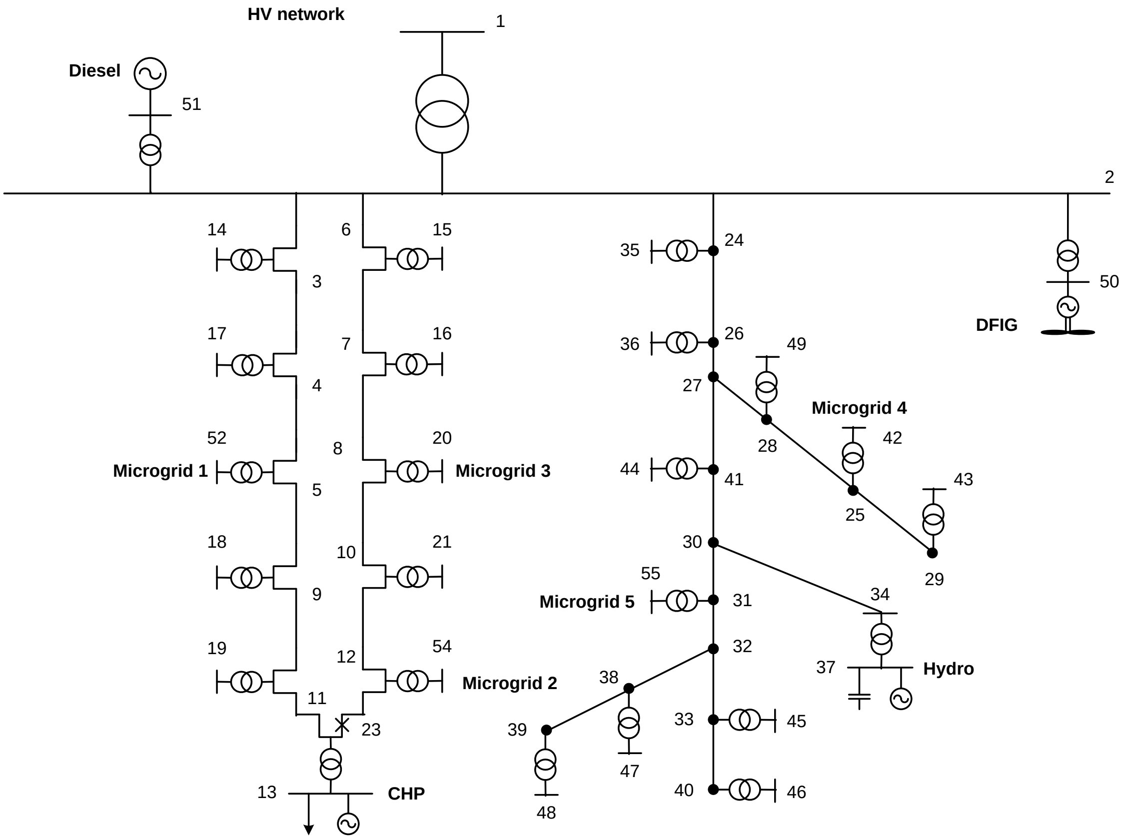

Figure B-2 – MV Network 2

The line data for this network is presented in Table B-5.

Table B-5 – Line Data for MV Network 2

Branch Number	From Bus	To Bus	Resistance [Ω]	Reactance [Ω]	Shunt Susceptance [Ω]
1	3	2	0,0204	0,0151	2,76E-05
2	4	3	0,0204	0,0151	2,76E-05
3	5	4	0,0204	0,0151	2,76E-05
4	6	7	0,0204	0,0151	2,76E-05
5	6	2	0,0204	0,0151	2,76E-05
6	7	8	0,0204	0,0151	2,76E-05
7	8	10	0,0204	0,0151	2,76E-05
8	9	5	0,0204	0,0151	2,76E-05
9	10	12	0,0204	0,0151	2,76E-05
10	11	9	0,0204	0,0151	2,76E-05
11	11	23	0,0204	0,0151	2,76E-05
12	12	23	0,0204	0,0151	2,76E-05
13	24	26	0,2924	0,1576	2,90E-06
14	24	2	0,2924	0,1576	2,90E-06
15	25	29	0,2924	0,1576	2,90E-06
16	26	27	0,2924	0,1576	2,90E-06

Branch Number	From Bus	To Bus	Resistance [Ω]	Reactance [Ω]	Shunt Susceptance [Ω]
17	27	28	0,2924	0,1576	2,90E-06
18	27	41	0,2924	0,1576	2,90E-06
19	28	25	0,2924	0,1576	2,90E-06
20	30	31	0,2924	0,1576	2,90E-06
21	30	34	0,2924	0,1576	2,90E-06
22	31	32	0,2924	0,1576	2,90E-06
23	32	33	0,2924	0,1576	2,90E-06
24	32	38	0,2924	0,1576	2,90E-06
25	33	40	0,2924	0,1576	2,90E-06
26	38	39	0,2924	0,1576	2,90E-06
27	41	30	0,2924	0,1576	2,90E-06
28	53	1	0,0017	0,0058	9,50E-04

The transformer data for this network is presented in Table B-6.

Table B-6 – Transformer Data for MV Network 2

Branch Number	From Bus	To Bus	Rated Power [MVA]	Primary Voltage [kV]	Secondary Voltage [kV]	Reactance [%]
1	1	2	20	150	15	5
2	2	22	2	15	0,4	5
3	2	50	10	15	0,4	5
4	3	14	1,26	15	0,4	5
5	4	17	1,26	15	0,4	5
6	6	15	1,26	15	0,4	5
7	7	16	1,26	15	0,4	5
8	8	20	0,4	15	0,4	5
9	9	18	0,63	15	0,4	5
10	10	21	0,63	15	0,4	5
11	11	19	0,63	15	0,4	5
12	12	54	0,63	15	0,4	5
13	23	13	2	15	0,4	5
14	24	35	0,4	15	0,4	5
15	25	42	0,25	15	0,4	5
16	26	36	0,25	15	0,4	5
17	28	49	0,4	15	0,4	5
18	29	43	0,16	15	0,4	5
19	31	55	0,4	15	0,4	5
20	33	45	0,25	15	0,4	5
21	37	34	2,5	15	0,4	5
22	40	46	0,16	15	0,4	5
23	41	44	0,4	15	0,4	5
24	47	38	0,25	15	0,4	5
25	48	39	0,16	15	0,4	5
26	51	2	4	15	0,4	5
27	52	5	0,4	15	0,4	5

The load data for this network is presented in Table B-7.

Table B-7 – Load Data for MV Network 2

Bus Number	Load Installed Capacity [MVA]
13	n/a
14	1,26
15	1,26
16	1,26
17	1,26
18	0,63
19	0,63
21	0,63
35	0,4
36	0,25
42	0,25
43	0,16
44	0,4
45	0,25
46	0,16
47	0,25
48	0,16

The generation data for this network is presented in Table B-8.

Table B-8 – Generation Data for MV Network 2

Bus Number	Generation Installed Capacity [MVA]
13	2,2
20	0,25
37	2,9
49	0,25
50	9
51	1,5
52	0,25
53	60
54	0,25
55	0,25

B-3 Low Voltage Network 1

As previously mentioned, LV Network 1 is a 100 kVA distribution grid from a rural environment. A one-line diagram of this network is presented in Figure B-3.

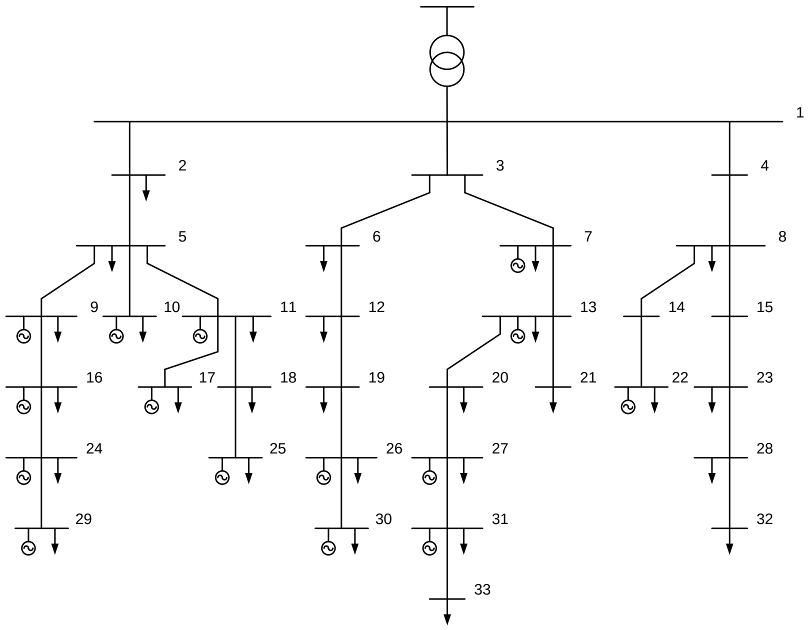

Figure B-3 – LV Network 1

The line data for this network is presented in Table B-9.

Table B-9 – Line Data for LV Network 1

Branch Number	From Bus	To Bus	Phase Resistance [Ω]	Phase Reactance [Ω]	Neutral Resistance [Ω]
1	1	2	0,0567	5,7E-06	5,7E-06
2	1	3	0,0190	1,9E-06	1,9E-06
3	1	4	0,0367	3,7E-06	3,7E-06
4	2	5	0,0310	3,1E-06	3,1E-06
5	3	6	0,0769	1,2E-05	1,2E-05
6	3	7	0,0700	7,0E-06	7,0E-06
7	4	8	0,0667	6,7E-06	6,7E-06
8	5	9	0,0467	4,7E-06	4,7E-06
9	5	10	0,1040	1,6E-05	1,6E-05
10	5	11	0,2187	2,2E-05	2,2E-05
11	6	12	0,2917	2,9E-05	2,9E-05
12	7	13	0,0233	2,3E-06	2,3E-06
13	8	14	0,1989	3,0E-05	3,0E-05
14	8	15	0,1242	1,9E-05	1,9E-05
15	9	16	0,0233	2,3E-06	2,3E-06
16	11	17	0,2496	3,7E-05	3,7E-05
17	11	18	0,0955	1,4E-05	1,4E-05
18	12	19	0,0381	3,8E-06	3,8E-06
19	13	20	0,1528	2,3E-05	2,3E-05
20	13	21	0,4841	7,3E-05	7,3E-05
21	14	22	1,2121	1,8E-04	1,8E-04
22	15	23	0,2674	4,0E-05	4,0E-05
23	16	24	0,0467	4,7E-06	4,7E-06

Branch Number	From Bus	To Bus	Phase Resistance [Ω]	Phase Reactance [Ω]	Neutral Resistance [Ω]
24	18	25	0,1614	2,4E-05	2,4E-05
25	19	26	0,0238	2,4E-06	2,4E-06
26	20	27	0,1875	1,9E-05	1,9E-05
27	23	28	0,9345	9,3E-05	9,3E-05
28	24	29	0,1844	2,8E-05	2,8E-05
29	26	30	0,0533	5,3E-06	5,3E-06
30	27	31	0,2142	3,2E-05	3,2E-05
31	28	32	0,3227	4,8E-05	4,8E-05
32	31	33	0,1614	2,4E-05	2,4E-05

The load data for this network is presented in Table B-10. In order to compute active and reactive power, a value of $\tan\varphi$ = 0,4 was used.

Table B-10 – Load Data for LV Network 1

Bus Number	Load Installed Capacity [kVA]		
	Phase A	Phase B	Phase C
2	3,45	3,45	0
5	0	0	3,45
6	1,15	0	0
7	10,35	0	0
8	3,45	3,45	3,45
9	6,9	3,45	3,45
10	3,45	13,8	0
11	3,45	0	6,9
12	3,45	3,45	0
13	6,9	3,45	3,45
16	0	6,9	0
17	13,8	0	0
18	0	3,45	3,45
19	3,45	3,45	0
20	0	3,45	3,45
22	10,35	3,45	3,45
23	0	0	3,45
24	20,7	17,25	20,7
25	0	3,45	13,8
26	0	13,8	0
27	6,9	3,45	3,45
29	3,45	3,45	10,35
30	0	0	13,8
31	0	6,9	0
32	0	3,45	3,45
33	0	0	3,45

The generation data for this network is presented in Table B-11.

Table B-11 – Generation Data for LV Network 1

Bus Number	Generation Installed Capacity [kVA]		
	Phase A	Phase B	Phase C

7	5,175	0	0
9	3,45	0	0
10	0	5,75	0
11	0	0	3,45
13	3,45	0	0
16	0	3,45	0
17	5,75	0	0
22	5,175	0	0
24	5,75	5,75	5,75
25	0	0	5,75
26	0	5,75	0
27	3,45	0	0
29	0	0	5,175
30	0	0	5,75
31	0	3,45	0

B-4 Low Voltage Network 2

As previously mentioned, LV Network 2 is a 630 kVA distribution grid from a semi-urban environment. A one-line diagram of this network is presented in Figure B-4.

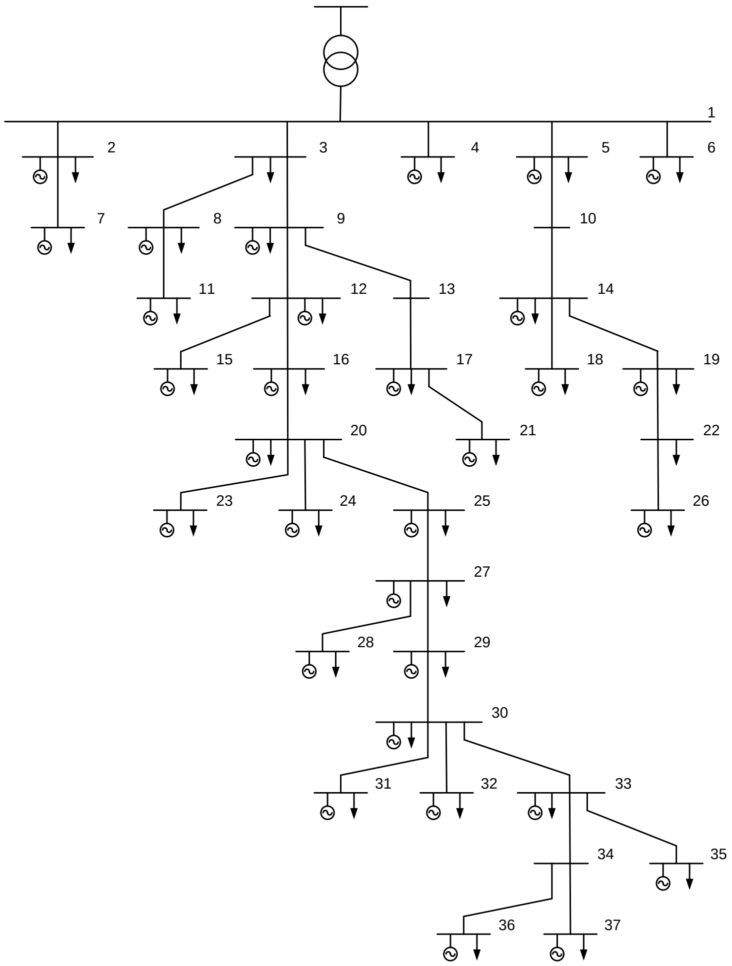

Figure B-4 – LV Network 2

The line data for this network is presented in Table B-12.

Table B-12 – Line Data for LV Network 2

Branch Number	From Bus	To Bus	Phase Resistance [Ω]	Phase Reactance [Ω]	Neutral Resistance [Ω]
1	1	2	0,0115	6,4E-03	1,1E-02
2	1	3	0,0099	5,5E-03	9,9E-03
3	1	4	0,0011	6,3E-04	1,1E-03
4	1	5	0,0061	3,4E-03	6,1E-03
5	1	6	0,0185	5,3E-03	1,9E-02
6	2	7	0,0051	2,3E-03	5,1E-03
7	3	8	0,0042	1,9E-03	4,2E-03
8	3	9	0,0096	4,3E-03	9,6E-03
9	5	10	0,0018	3,8E-04	1,8E-03
10	8	11	0,0017	7,5E-04	1,7E-03
11	9	12	0,0050	7,5E-04	5,0E-03
12	9	13	0,0337	5,1E-03	3,4E-02
13	10	14	0,0125	1,9E-03	1,3E-02

Branch Number	From Bus	To Bus	Phase Resistance [Ω]	Phase Reactance [Ω]	Neutral Resistance [Ω]
14	12	15	0,0167	1,3E-03	1,7E-02
15	12	16	0,0228	3,4E-03	2,3E-02
16	13	17	0,0217	3,3E-03	2,2E-02
17	14	18	0,0300	2,3E-03	3,0E-02
18	14	19	0,0367	5,5E-03	3,7E-02
19	16	20	0,0058	8,8E-04	5,8E-03
20	17	21	0,0383	5,8E-03	3,8E-02
21	19	22	0,0117	1,8E-03	1,2E-02
22	20	23	0,0167	1,3E-03	1,7E-02
23	20	24	0,0133	1,0E-03	1,3E-02
24	20	25	0,0050	7,5E-04	5,0E-03
25	22	26	0,0469	2,3E-03	4,7E-02
26	25	27	0,0108	1,6E-03	1,1E-02
27	27	28	0,0100	1,5E-03	1,0E-02
28	27	29	0,0067	1,0E-03	6,7E-03
29	29	30	0,0083	1,3E-03	8,3E-03
30	30	31	0,0117	8,8E-04	1,2E-02
31	30	32	0,0067	5,0E-04	6,7E-03
32	30	33	0,0050	7,5E-04	5,0E-03
33	33	34	0,0083	0,0006	8,3E-03
34	33	35	0,0092	0,0014	9,2E-03
35	34	36	0,0067	0,0005	6,7E-03
36	34	37	0,0667	0,0050	6,7E-02

The load data for this network is presented in Table B-13. In order to compute active and reactive power, a value of tan φ = 0,4 was used.

Table B-13 – Load Data for LV Network 2

Bus Number	Load Installed Capacity [kVA]		
	Phase A	Phase B	Phase C
2	23	23	21,85
3	5,75	5,75	5,75
4	29	29	29
5	24,2	24,2	24,2
6	6,9	6,9	6,9
7	31,05	31,05	34,5
8	13,8	13,8	13,8
9	6,9	3,45	0
11	16,1	16,1	23
12	48,3	48,3	48,3
14	0	6,9	0
15	12,65	9,2	9,2
16	26,45	28,75	28,75
17	29,9	23	23
18	19,55	19,55	23
19	20,7	27,6	24,15
20	16,1	9,2	16,1
21	14,95	18,4	14,95
22	0	3,45	0
23	12,65	5,75	5,75

Bus Number	Load Installed Capacity [kVA]		
	Phase A	Phase B	Phase C
24	10,35	10,35	10,35
25	8,05	11,5	14,95
26	13,8	13,8	13,8
27	9,2	11,5	8,05
28	6,9	3,45	10,35
29	17,25	24,15	17,25
30	11,5	4,6	10,35
31	10,35	13,8	10,35
32	9,2	5,75	2,3
33	3,45	6,9	10,35
35	25,3	25,3	21,85
36	9,2	9,2	12,65
37	12,65	12,65	5,75

The generation data for this network is presented in Table B-14.

Table B-14 – Generation Data for LV Network 2

Bus Number	Generation Installed Capacity [kVA]		
	Phase A	Phase B	Phase C
2	5,75	5,75	5,75
4	5,75	5,75	5,75
5	5,75	5,75	5,75
6	3,45	3,45	3,45
7	5,75	5,75	5,75
8	5,75	5,75	5,75
9	3,45	0	0
11	5,75	5,75	5,75
12	5,75	5,75	5,75
14	0	3,45	0
15	5,75	4,6	4,6
16	5,75	5,75	5,75
17	5,75	5,75	5,75
18	5,75	5,75	5,75
19	5,75	5,75	5,75
20	5,75	4,6	5,75
21	5,75	5,75	5,75
23	5,75	0	0
24	5,175	5,175	5,175
25	4,025	5,75	5,75
26	5,75	5,75	5,75
27	4,6	5,75	4,025
28	3,45	0	5,175
29	5,75	5,75	5,75
30	5,75	0	5,175
31	5,175	5,75	5,175
32	4,6	0	0
33	0	3,45	5,175
35	5,75	5,75	5,75
36	4,6	4,6	5,75
37	5,75	5,75	0

B-5 Low Voltage Network 3

As previously mentioned, LV Network 3 is a 100 kVA distribution grid from a rural environment. A one-line diagram of this network is presented in Figure B-5.

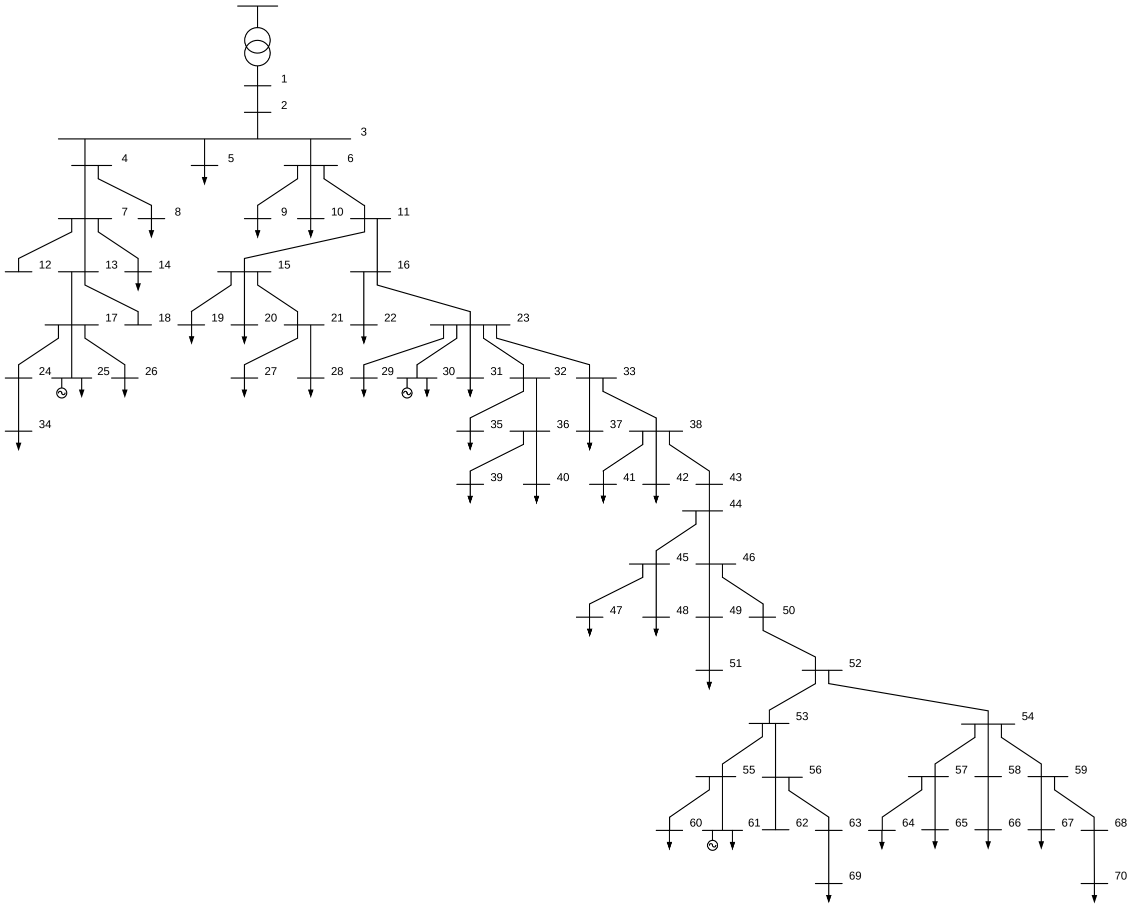

Figure B-5 – LV Network 3

The line data for this network is presented in Table B-15.

Table B-15 – Line Data for LV Network 3

Branch Number	From Bus	To Bus	Phase Resistance [Ω]	Phase Reactance [Ω]	Neutral Resistance [Ω]
1	1	2	0,0027	6,3E-04	2,7E-03
2	2	3	0,0174	3,6E-03	2,4E-02
3	3	4	0,0247	3,8E-03	2,5E-02
4	3	5	0,0240	1,2E-03	2,4E-02
5	3	6	0,0189	2,9E-03	1,9E-02
6	4	7	0,0274	4,2E-03	2,7E-02
7	4	8	0,0261	3,7E-04	2,6E-02
8	6	9	0,0288	4,0E-04	2,9E-02
9	6	10	0,0133	6,7E-04	1,3E-02
10	6	11	0,0195	3,0E-03	2,0E-02
11	7	12	0,0183	2,8E-03	1,8E-02
12	7	13	0,0110	1,4E-03	1,1E-02
13	7	14	0,0144	7,3E-04	1,4E-02
14	11	15	0,0123	1,5E-03	1,2E-02

Branch Number	From Bus	To Bus	Phase Resistance [Ω]	Phase Reactance [Ω]	Neutral Resistance [Ω]
15	11	16	0,0159	2,4E-03	1,6E-02
16	13	17	0,0143	1,8E-03	1,4E-02
17	13	18	0,0064	3,3E-04	6,4E-03
18	15	19	0,0078	4,0E-04	7,8E-03
19	15	20	0,0116	5,9E-04	1,2E-02
20	15	21	0,0111	1,4E-03	1,1E-02
21	16	22	0,0315	1,6E-03	3,1E-02
22	16	23	0,0149	2,3E-03	1,5E-02
23	17	24	0,0282	3,5E-03	2,8E-02
24	17	25	0,0212	1,1E-03	2,1E-02
25	17	26	0,0170	8,6E-04	1,7E-02
26	21	27	0,0180	9,1E-04	1,8E-02
27	21	28	0,0097	4,9E-04	9,7E-03
28	23	29	0,0184	9,3E-04	1,8E-02
29	23	30	0,0029	1,5E-04	2,9E-03
30	23	31	0,0221	1,1E-03	2,2E-02
31	23	32	0,0133	1,7E-03	1,3E-02
32	23	33	0,0195	3,0E-03	1,9E-02
33	24	34	0,0340	0,0017	3,4E-02
34	32	35	0,1147	0,0058	1,1E-01
35	32	36	0,0118	0,0015	1,2E-02
36	33	37	0,0118	0,0006	1,2E-02
37	33	38	0,0284	0,0043	2,8E-02
38	36	39	0,0220	0,0011	2,2E-02
39	36	40	0,0207	0,0003	2,1E-02
40	38	41	0,0832	0,0007	8,3E-02
41	38	42	0,0159	0,0008	1,6E-02
42	38	43	0,1456	0,0222	1,5E-01
43	43	44	0,0067	0,0016	6,7E-03
44	44	45	0,0306	0,0015	3,1E-02
45	44	46	0,0109	0,0026	1,1E-02
46	45	47	0,0071	0,0001	7,1E-03
47	45	48	0,0067	0,0001	6,7E-03
48	46	49	0,0537	0,0027	5,4E-02
49	46	50	0,0129	0,0030	1,3E-02
50	49	51	0,0034	0,0001	3,4E-03
51	50	52	0,0220	0,0034	2,2E-02
52	52	53	0,0175	0,0027	1,7E-02
53	52	54	0,0334	0,0042	3,3E-02
54	53	55	0,0142	0,0007	1,4E-02
55	53	56	0,0248	0,0031	2,5E-02
56	54	57	0,0072	0,0009	7,2E-03
57	54	58	0,0385	0,0059	3,9E-02
58	54	59	0,0514	0,0078	5,1E-02
59	55	60	0,0043	0,0001	4,3E-03
60	55	61	0,0098	0,0005	9,8E-03
61	56	62	0,0055	0,0003	5,5E-03
62	56	63	0,0141	0,0018	1,4E-02
63	57	64	0,0050	0,0003	5,0E-03
64	57	65	0,0245	0,0012	2,4E-02
65	58	66	0,0147	0,0001	1,5E-02
66	59	67	0,0123	0,0001	1,2E-02

Branch Number	From Bus	To Bus	Phase Resistance [Ω]	Phase Reactance [Ω]	Neutral Resistance [Ω]
67	59	68	0,0593	0,0090	5,9E-02
68	63	69	0,0129	0,0007	1,3E-02
69	68	70	0,0173	0,0009	1,7E-02

The load data for this network is presented in Table B-16. In order to compute active and reactive power, a value of tan φ = 0,4 was used.

Table B-16 – Load Data for LV Network 3

Bus Number	Load Installed Capacity [kVA]		
	Phase A	Phase B	Phase C
5	3,45	0	0
8	0	3,45	0
9	0	0	3,45
10	3,45	0	0
14	0	3,45	0
19	0	0	6,9
20	3,45	0	0
22	0	3,45	0
25	6,9	0	0
26	0	3,45	0
27	0	0	3,45
28	0	3,45	0
29	0	0	3,45
30	10,35	0	0
31	0	1,15	0
34	0	0	3,45
35	0	3,45	0
37	0	0	3,45
39	0	3,45	0
40	0	0	3,45
41	3,45	0	0
42	0	3,45	0
47	0	0	3,45
48	3,45	0	0
51	0	1,15	0
60	0	0	3,45
61	0	2,3	0
64	0	0	3,45
65	0	10,35	0
66	0	0	3,45
67	3,45	0	0
69	3,45	0	0
70	1,15	0	0

The generation data for this network is presented in Table B-17.

Table B-17 – Generation Data for LV Network 3

Bus Number	Generation Installed Capacity [kVA]		
	Phase A	Phase B	Phase C
19	0	0	3,45
25	3,45	0	0
30	5,175	0	0
65	0	5,175	0

Appendix C – Load and Generation Scenarios

In this appendix, the profiles for generation and load concerning the 24-hours of a day used in Section 6.3.3.2 are presented. These profiles were based on real data, using typical curves for each generation technology and a typical load profile for a predominantly residential area.

C-1 Combined Heat and Power Generation Unit Profile

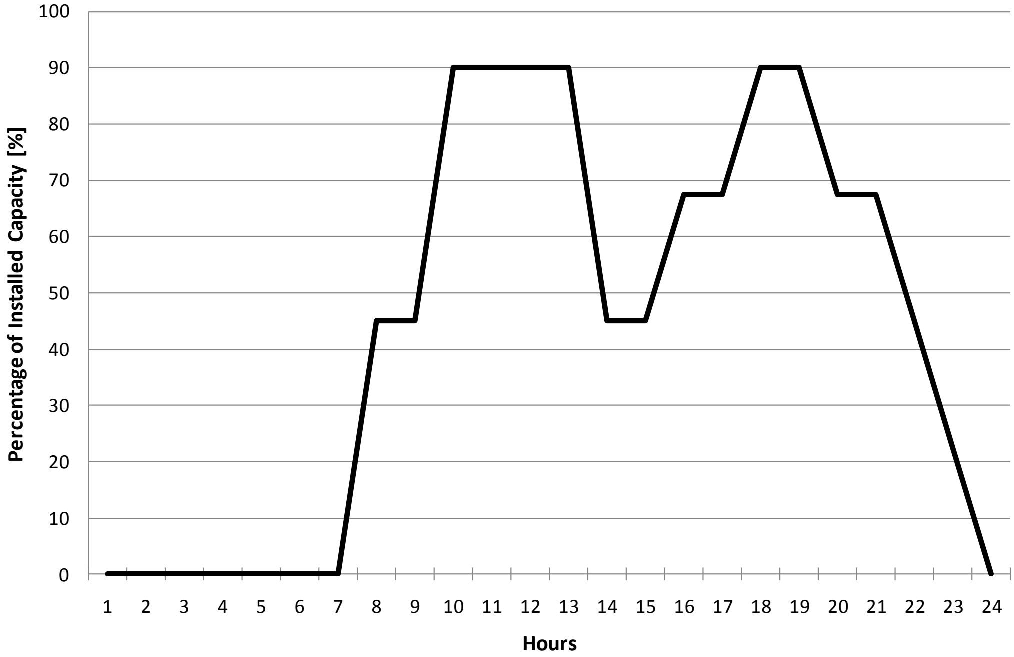

Figure C-1 – 24-hours Generation Profile for CHP Unit

C-2 Doubly-Fed Induction Generators Profile

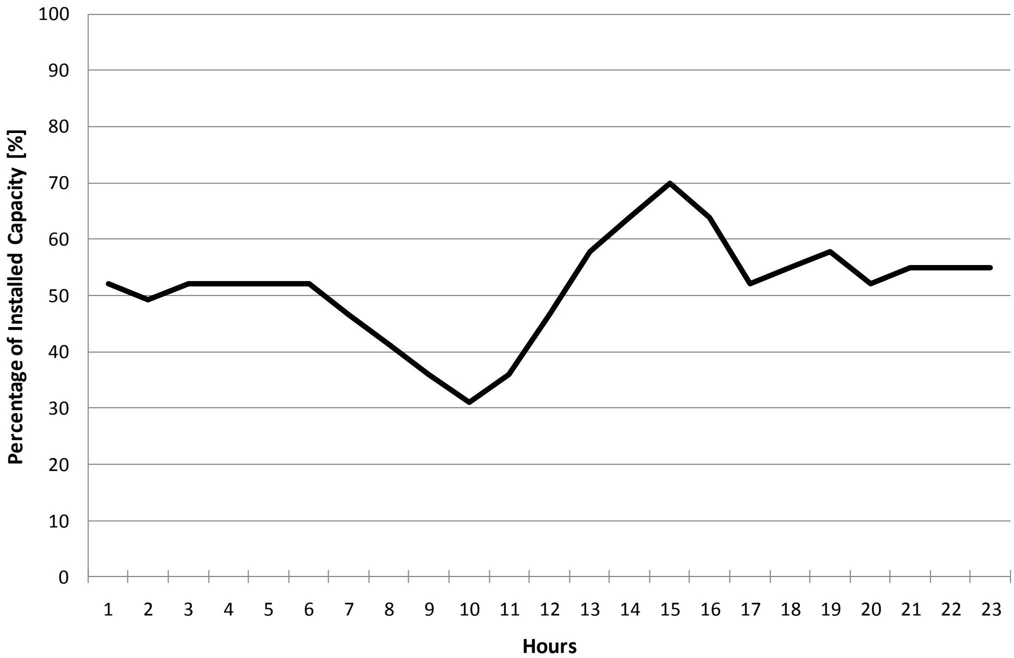

Figure C-2 – 24-hours Generation Profile for DFIG Unit

C-3 Photovoltaic Microgeneration Units Profile

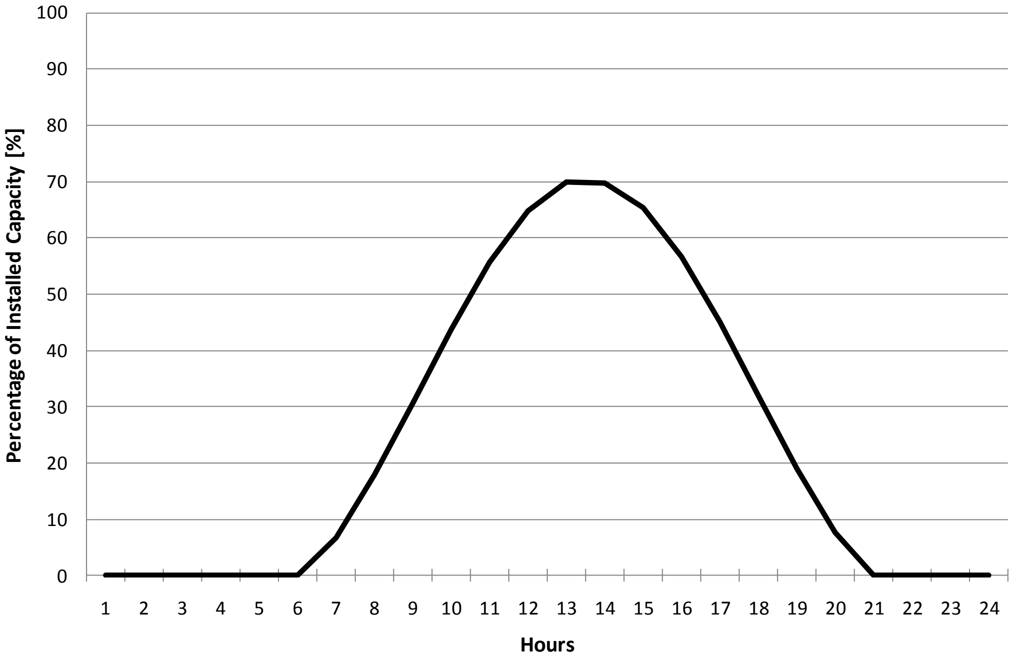

Figure C-3 – 24-hours Generation Profile for PV Unit

C-4 Load Profile

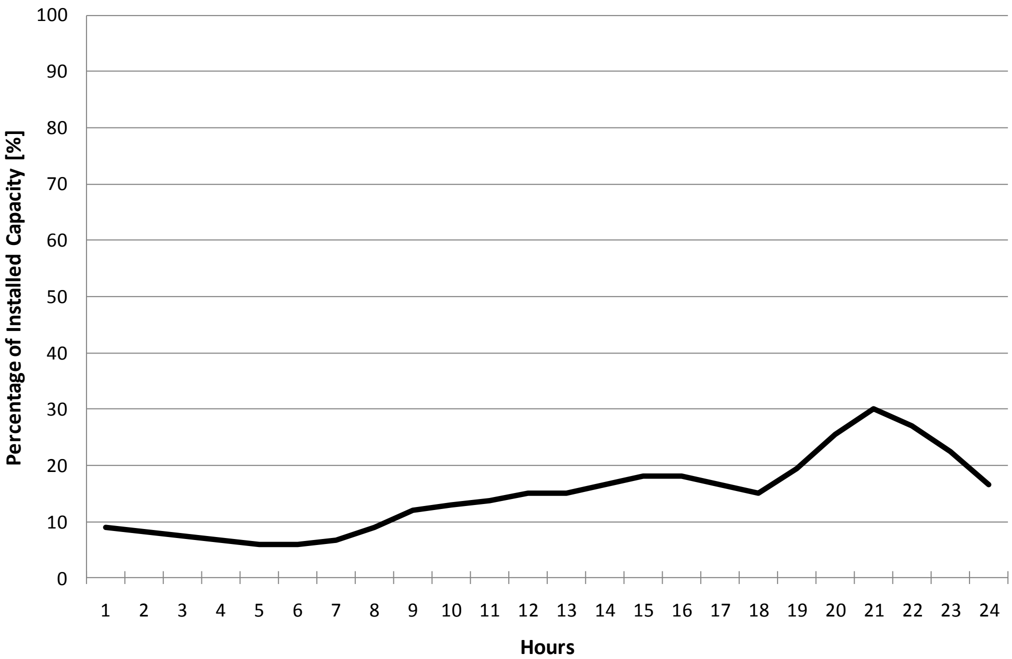

Figure C-4 – 24-hours Generation Profile for Residential Load