Operational Voltage Control of Future Distribution Networks

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A thesis presented in fulfilment of the requirements for the degree of Doctor of Philosophy

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Signed: Date:

To my Father CAO Wen

&

In loving memory of my Mother LIANG ShuYing

Abstract

Voltages in distribution networks are subject to variations primarily due to varying demand and the intermittent nature of growing renewable generation. Conventionally voltages are regulated only at certain locations such as distribution substations with some fixed settings for control equipment such as voltage targets or tap changers of under-load tap changing (ULTC) transformers and switching status of shunt capacitors. These settings are normally determined by operators in control rooms and are changed on the condition that power supply cannot be adequately delivered. A fixed constant setting for the controllable devices may not guarantee secured voltage profiles for all load centres at all times during the course of a day and may lead to frequent operations due to fluctuations in generation and demand profiles, which will eventually lead to wear on the control equipment.

This thesis investigates the operational control of voltages on distribution networks and proposes a control strategy that manages voltage control devices from an operational planning perspective in order to maintain a desired level of voltage security by applying the most cost-effective control actions. The proposed methodology integrates power system sensitivity analysis and an artificial intelligence (AI) planning approach to schedule voltage control actions for a given electrical system across a specific planning time period based on known generation and demand profiles. The concept of a failsafe mode is incorporated into the proposed control strategy to deal with the potential loss of data communication or ultimate failure of the planned solutions. A typical radial distribution network model was studied under a range of scenarios and the simulation results demonstrated that the proposed methodology was capable of automatically planning control settings for ULTC transformers and MSCs to maintain requisite voltage limits and outperformed the conventional methods by eliminating the number of voltage violations and also reducing the number of control operations. The flexibility of the proposed methodology allows it to be integrated to the existing software platforms used by some of the UK distribution network operators (DNOs).

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List of Abbreviations, Symbols & Nomenclatures

The following are the abbreviations, symbols and nomenclatures used throughout this thesis.

Abbreviations

ACO	Ant colony optimisation
AI	Artificial Intelligence
AGC	Automatic Generation Control
ANM	Active Network Management
ANN	Artificial Neural Network
ARS	Automatic Reactive Switching
AVC	Automatic Voltage Control
AVR	Automatic voltage regulator
BETTA	British Electricity Trading & Transmission Arrangements
CCC	Circulating current compensation
CHP	Combined Heat and Power
CI	Customer interruptions
CML	Customer minutes lost
CSV	Comma separated value
DA	Distribution Automation
DB	Deadband
DAR	Delayed auto-reclose
DC	Direct current
DFIG	Doubly fed induction generator
DG	Distributed Generator
DisCo	Distribution Company
DMS	Distribution Management System
DNO	Distribution Network Operator
DP	Dynamic Programming
DPCR	Distribution Price Control Review

DSO	Distribution System Operator
DUKES	Digest of United Kingdom Energy Statistics
EHV	Extra-high voltage
EMS	Energy Management System
ENA	Energy Network Association
ENSG	Electricity Networks Strategy Group
ER	Engineering Recommendations
FACTS	Flexible AC transmission systems
FDLF	Fast Decoupled Load Flow
FITs	Feed-in Tariffs
FRC	Fully rated converter
FSIG	Fixed speed induction generator
G-S	Gauss Seidel
GB	Great Britain
GenCo	Generation Company
GSA	Gravitational search algorithm
GSP	Grid Supply Point
HiDEF	Highly Distributed Energy Future
HMI	Human-machine interface
HV	High Voltage
IC	Internal combustion
IED	Intelligent electronic device
IFI	Innovation Funding Incentive
IPM	Interior point method
IPSA	Interactive Power System Analysis (a commercial software tool)
LCNF	Low Carbon Networks Fund
LDC	Line drop compensation
LFC	Load Frequency Control
LP	Linear programming
LV	Low Voltage
MAS	Multi-agent systems
MD	Maximum demand
MSC	Mechanically switched capacitor
MSR	Mechanically switched reactor
MV	Medium Voltage

MW	Megawatt
MWh	Megawatt-hour
NETA	New Electricity Trading Arrangements (BETTA's predecessor)
NGET	National Grid Electricity Transmission
N-R	Newton Raphson
NLP	Nonlinear programming
NOP	Normally open point
NSGA	Non-dominance Sorting Genetic Algorithm
Ofgem	Office of Gas and Electricity Markets
OHL	Overhead line
OPF	Optimal Power Flow
OOP	Object oriented programming
PFC	Power factor control
PLC	Programming logic controller
PSO	Particle swarm optimisation
PV	Photovoltaic
RIIO	Revenue = Incentives + Innovation + Outputs
RO	Renewable Obligation
RPD	Reactive power dispatch
RPP	reactive power planning
RPZ	Registered Power Zone
RTU	Remote terminal unit
QP	Quadratic programming
SCADA	Supervisory Control and Data Acquisition
SGT	Supergrid transformer
SHETL	Scottish Hydro Electricity Transmission Limited
SO	System Operator
SOA	Seeker optimisation algorithm
SP	Scottish Power
SPEN	Scottish Power Energy Networks
SPTL	Scottish Power Transmission Limited
SQSS	Security and Quality of Supply Standard
SVC	Static VAr Compensator
TAPP	Transformer Automatic Paralleling Package
TranCo	Transmission Company

TSO	Transmission System Operator
UGC	Underground cable
UK	United Kingdom
UKWED	UK Wind Energy Database
ULTC	Under-load tap-changing (transformer)
UPF	Unity power factor
VAR	Volt ampere reactive
VCR	Voltage control relay
VOLTS	Variable on-line transformer scheduling

Symbols and nomenclatures

Δt	Transformer tap step change
ΔV	Voltage change
ΔP, ΔQ	Active and reactive power change
$\mathit{\Delta}$	Voltage phase angle
Θ	Admittance phase angle
J	Jacobian matrix
I	Current
N_{max}	Maximum number of iterations/operations
p.f.	Power factor
p.u.	Per unit
P, Q	Active and reactive power
P_g	Active power generation
Q_{gmax}, Q_{gmin}	Upper and lower limits for reactive power generation
P_d, Q_d	Active and reactive power demand
V	Voltage magnitude
V_{max}, V_{min}	Maximum and minimum voltage
V_0	Reference or target voltage for tap-changing transformers
V_b	Bandwidth/DB setting for tap-changing transformers
Re, Im	Real and Imaginary part of a complex number
S_d	Apparent power demand

S_{xu}	Sensitivity matrix
R, X	Resistance and reactance
G, B	Conductance and susceptance
Z, Y	Impedance and admittance

1. Introduction

This chapter lays out an overview of this thesis including its background, research motivations, overall objectives and the importance of the work. Original contributions from this work are highlighted and an outline of the chapter structures is illustrated. Also included in this chapter are a list of associated publications and presentations.

1.1 Thesis Background

In this section, the history and development of the electricity industry is introduced along with the different roles the major participants play and the fundamental principles concerning the operation and control of power systems. The management of distribution networks is discussed and the future trend of the electric industry and associated rising challenges are highlighted, followed by the introduction of the concept of smart grid.

1.1.1 History and Development of Power Systems

Electricity, as a commodity, is essential for keeping industries of all fields in regular service and households' demand satisfied. It is one of the most principal resources in modern society and plays a vital part in maintaining economic prosperity. In the early 1880s, electric power was first generated by direct current (DC) generators that were powered by steam engines and the power was delivered for incandescent lighting at 110V to a number of customers located within the vicinity of one square-mile; it is often deemed as the starting point for the electric utility industry. Driven by the growing need for electricity, three-wire 220V DC systems were developed and expanded at a rapid pace, but the maximum power delivery distance and capacity were limited and could not keep up with the growing demand due to long-distance voltage drops. These drawbacks of DC transmission systems were then overcome by the development of power transformers designed to elevate voltage levels to allow more power to be transmitted to wider geographical areas [1]. Meanwhile, alternating current (AC) single phase transmission lines were developed and used alongside AC power transformers, which made AC transmission systems become a viable alternative to DC systems. The use of AC systems then became more favourable than DC systems owing to the capability to deliver power at high voltages with smaller amount of current and lower voltage drops over long distances. The development of three phase systems prompted AC systems to be even more prevalent due to the simplicity and cost-effectiveness of the design. As a result, AC systems became the standardised system for power industry by the turn of the 19th century [2].

To better utilise various energy resources amongst different countries, international interconnections were developed swiftly, which prompted system frequency to be standardised in late 1890s and early 1900s. The typical standard frequencies used in electricity generation, transmission and distribution in the world are 60 Hz and 50 Hz [1]. A variety of voltage levels were used in many countries throughout 1990s and finally became standardised at national levels in late 1990s. In the United Kingdom (UK), the standards are 132, 275 and 400kV for high voltage (HV) levels; 3.3, 11, 33 and 66kV for medium voltage (MV) levels; 230 and 400V for low voltage (LV) levels. [1] As the demand for electricity kept growing, the capacity of generating units accordingly developed and expanded at a fast pace. Power generation, transmission, distribution and utilisation together constitute an electrical power system. Electricity generation normally involves the conversion of energy from other forms into the electrical form, using steam-powered, water-powered and internal-combustion engines that are primarily fuelled by coal, gas, oil and uranium. Electric power is conventionally generated at LV levels ranging from 11kV to 35kV, transmitted via transmission systems at HV levels and supplied through distribution systems at MV levels and delivered to a variety of users at MV and LV levels.

In some countries, there exists a vertically integrated utility that has the ownership of generation, transmission and sometimes distribution systems, centrally controlling the entire power delivery process and electricity trading. Although this highly

[1] The voltage level of 132kV is regarded as transmission system in Scotland but as distribution system in England and Wales.

centralised regulating mechanism is likely to ensure the overall safety of power grid operation, its natural monopoly nature places users in a passive position with little or even no choice of electricity suppliers and there is a lack of incentives upon improvement of services or technology innovation. Competition has been introduced to electricity markets in many countries in order to grant consumers with choices on electricity suppliers; this in turn spurs opportunities for devising incentives on cost and price reduction by improving the efficiency of power generation and transmission with technological innovation [3]. Hence in these countries electricity market structures have become reformed with the ownership of different sectors privatised. The traditional vertically integrated utility structure became vertically unbundled, i.e. divided into generation owned by generation companies (GenCo), transmission by Transmission Companies (TranCo), distribution by Distribution Companies (DisCo) and retail sectors who sell electricity to customers; an independent entity, known as the system operator (SO), is held primarily responsible for maintaining the security of power system operation and a market operator is the entity that regulates the trading environment for power exchange [4]. [2]

In the UK, the deregulation of power industry was initially encouraged by the Energy Act established in 1983 and the actual market privatisation and liberalisation began in 1990 when the Electricity Pool was set up for the trading of electricity. Presently in the UK, National Grid Electricity Transmission (NGET) is the electricity and gas SO who also owns England and Wales transmission systems and is therefore also a transmission system operator (TSO); the TSOs managing the Scottish transmission systems are Scottish Power Transmission Limited (SPTL) and Scottish Hydro Electric Transmission Limited (SHETL) Companies. There are 14 licensed DNOs responsible for providing electrical services at distribution networks throughout the UK. The Electricity Pool was initially superseded by New Electricity Trading Arrangements (NETA) in 2001 and extended to be the British Electricity Trading & Transmission Arrangements (BETTA) in 2005, enabling the open access to transfer

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[2] One company may have several roles to play in power industry. For instance, Scottish Power (SP) Ltd, has several divisions: SP Power Systems Ltd is a DNO; SP Generation Holdings Ltd does power generation and energy retail business.

electricity across the borders between England and Scotland [5]. BETTA primarily involves the bilateral trading of electricity on a half-hourly basis amongst market participants such as generator owners, energy suppliers and customers. The electricity and gas trading market is regulated by the Office for Gas and Electricity Market (Ofgem), an independent party, to protect the interests of consumers [6]. An overview of the electricity market under BETTA is illustrated in Figure 1-1. It can be seen from the figure that the trading of electricity involves several stages over time: the trading of electricity initially takes place at the forward or future contract market 24 hours before the delivery and at the short term bilateral market 1-24 hours prior to delivery, followed by the Balancing Mechanism executed by the SO from Gate Closure (1 hour prior to delivery) to real-time delivery in order to continuously match demand and generation.

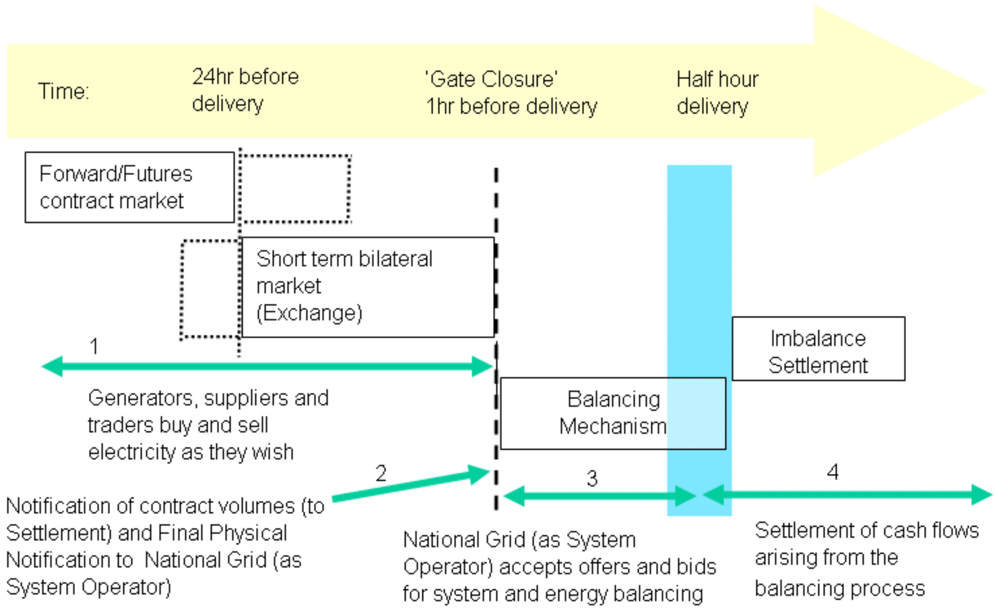

Figure 1-1 BETTA Market Structure ([6])

In 1998 the UK government passed a legally binding legislation under the Kyoto protocol, the aim of which was to reduce greenhouse gas emissions by 12.5% from the 1990 levels by 2008-2012 [7]. The Climate Change Act 2008 accelerated the pace by setting out a plan to further cut the emissions by 80% below the 1990 levels by 2050 [7]. Of the seven gases included in the Protocol, carbon dioxide is widely recognised for its greenhouse effect; it contributed to around 82% of the total UK greenhouse gas emissions in 2012 [8]. The primary sources of carbon emissions in power industry are from the production of electricity through combustion of fossil fuels and from the consumption of energy via household heating and cooling.

The UK government has put forward a range of incentives and policies to cut down electricity demand by households and to reduce the use of fossil fuels by resorting to renewable energy resources such as wind power, solar photovoltaic (PV), hydro power and domestic scaled micro-combined heat and power (CHP). Considering that renewable technologies are normally much more expensive than fossil fuel technologies, the Renewable Obligation (RO) was introduced in 2002 as a major financial incentive to promote the utilisation of renewable sources for electricity generation. Specifically, Renewables Obligation Certificates (ROCs) are issued by Ofgem to provide premium financial rates to generators for their available renewable power generation; energy suppliers must make sure that there is a required annual increase in the proportion of electricity generation from renewable sources by purchasing ROCs from generators [9]. Furthermore, the Feed-in Tariffs (FITs) scheme was initiated in 2010 to promote the connection and operation of small-scale low-carbon power generation whose capacities are less than 5 megawatt (MW) [10]. All these incentives and policies have led to a significant increase in the penetration of stochastic and intermittent renewable power in electrical supply networks at transmission systems and distribution networks, bringing in new challenges to the way TSOs and DNOs manage power systems. According to the Digest of UK energy statistics (DUKES), the percentage of electricity generation from renewable sources rose steadily from 2.8% in 2002 to 11.3% in 2012, shown in Figure 1-2 [11]. In addition to low-carbon electricity generation, the UK government also set up the Carbon Plan in 2011 [12] to place emphasis on other areas that can potentially contribute to carbon emissions including promoting cleaner transport by using ultra-low carbon vehicles (such as electric vehicles) as well as improving the household energy efficiency via enhanced insulation and sustainable heating systems. However, the potential impact of increasing use of electric vehicles on power grid operation is still being investigated [13]–[15].

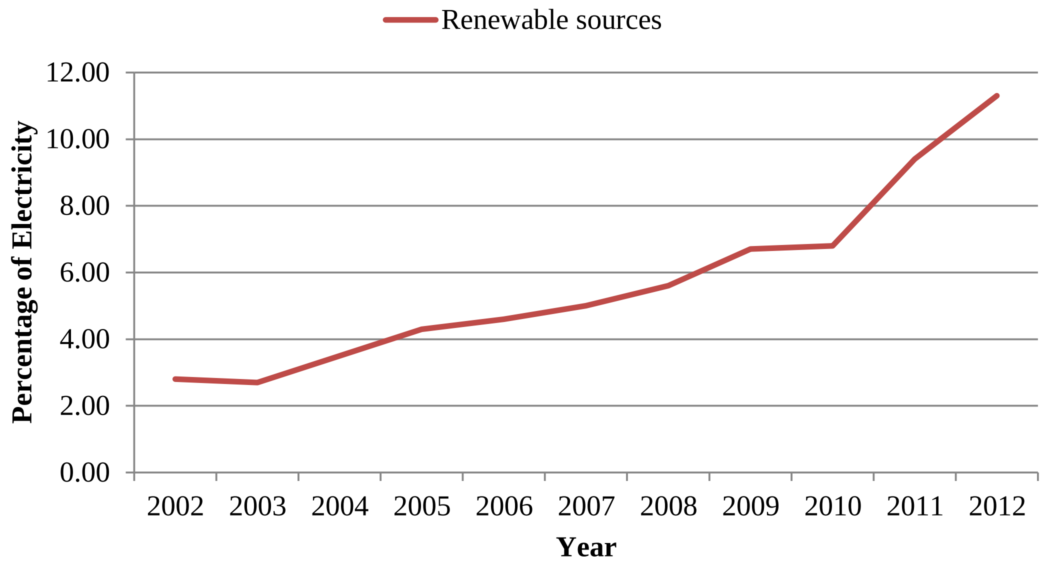

Figure 1-2 Growth of renewable electricity in total generation since 2002 ([11])

1.1.2 Operators' Responsibilities

Owing to the overall increasing world population and fast evolution of power generation and transmission technologies, a rapid growth in the overall demand and a dramatic change in generation composition have been seen in the global electricity sector during the last few decades, bringing unheralded challenges to SOs whose major responsibility is matching the changing demand with generation while coordinating different control mechanisms to ensure that power systems operate in a safe and reliable manner. Meanwhile, the decentralisation of the electricity sector, the growth of power utilities and the increase of network interconnections together have posed a challenging task to SOs in terms of effective operation of future power systems. Therefore SOs have had no option but to take a responsive approach to deliver their system operation objectives, in answer to a sector evolving to meet the demands of 21st century society [16].

Since power quality is inherently characterised by a desired level of frequency and voltage constancy, there are specific requirements on system frequency and voltages. TSOs and DNOs are normally responsible for controlling, regulating and maintaining power systems to comply with the requisite limits in a safe, economic and clean manner. In Great Britain (GB) power systems, such specifications are described in "Security and Quality of Supply Standard" (SQSS) [17] and the Grid Code [18] for transmission systems and in the Distribution Code [19] for distribution systems. Guidelines set by the Engineering Recommendations (ER) [20] are also often followed by TSOs and DNOs. In the UK, the DNOs are required to meet the standards specified in the Electricity Regulations covering supply restoration and voltage quality [21]; the performance of DNOs is reviewed in the following major areas: reliability and availability; customer satisfaction; connections; and environment [21]. While TSOs are normally capable of dispatching generation and managing storage and some responsive consumers under certain agreements, DNOs can only manage networks where demand and generation are non-flexible. Therefore, compared with TSOs, DNOs plays a relatively more passive role. Some DNOs such as UK Power Networks are seeking to participate more actively in grid control and to move towards the role of a distribution system operator (DSO), who has the capability to regulate responsive demand, storage and generators at distribution networks and can actively control the voltage levels and power flows with more flexibility [22]. The following challenges are to be dealt with by the SOs, TSOs and DNOs in the coming future [23]:

- Security of supply is subject to assessment due to growing intermittent renewable power in distribution and transmission systems as well as the continuous shutdown of large conventional power plants;
- The electricity sector is anticipated to go through unprecedented technical and commercial changes as the UK moves towards a low carbon future with the deployment of low carbon vehicles and energy saving product;
- Demand for electricity is forecasted to continuously rise in the coming decades due to electrification of transport and space heating propelled by the ambition to use lower carbon sources of energy and the fact that electricity is considered to be the most cost-effective energy vector;
- Environmental policies and incentives may result in rising electricity bills owing to the high investment costs of renewable generation technologies, expensive gas and oil prices and potential network upgrading or investment.

1.1.3 Management of Distribution Networks

As hardware and software technologies evolve, distribution automation (DA) has been developed and implemented with deployment of distribution Supervisory Control and Data Acquisition (SCADA) in some countries since as early as 1970s [24]. DA programmes have enabled DNOs to react to changing operating conditions while ensuring sufficient profit for shareholders with the following essential advantages [24]: reduced operation and maintenance costs; capacity project deferrals; improved reliability and power quality; better information for engineering and planning. Distribution automation and control functions that have been implemented in some countries are listed as follows [24]:

- SCADA
- Communicating relays in distribution substations
- Remotely controlled disconnecting switches
- Remote meter reading functions
- Fault location function with distribution management systems
- Actuation of controllable equipment such as circuit breakers and transformers
- Load management functions: discretionary load switching; load shedding; cold load pickup
- Real-time operational management functions: load reconfiguration; voltage regulation; transformer load management

However, surveys conducted from 1988 to 2000 indicated that a limited number of utilities in the world adopted DA while many did not due to high costs and lack of necessity. DA is applied to different levels of distribution networks with a systematic control hierarchy, from control centres to controllable equipment or devices such as generators, circuit breakers and transformer tap changers that are fitted with actuators or mechanisms designed to execute mechanical opening and closing operation or mechanical movement of tap positions [24]. The operation on these controllable devices is dependent upon communication links with control centres and intelligent electronic device (IED) which serve as the interface between the controllable equipment and the communication system. The Distribution

Management System (DMS) is frequently referred to within the DA domain; it addresses control functions performed in control rooms. The DMS coordinates real-time functions with non-real-time information such as manual operation of devices under both normal and emergency operating states. The practical management of distribution networks differs from that of transmission systems in a number of aspects. The key differences between transmission systems and distribution systems are summarised in section 2.3.1.

In recent decades, as the number of distributed generators (DGs) increase, management of distribution networks has proven to be more complicated due to the stochastic intermittent nature of renewable resources.[3] Other contributing factors involve the growing uptake of electric vehicles and implementation of energy efficient measures. The potential impacts of growing DG penetration upon traditional distribution networks without active controllers can be briefly summarised as [25]: increased fault levels and voltage levels; increased power flows through equipment; changing power flows along distribution feeders. In addition to these technical challenges, there are also regulatory and commercial imperatives to encourage DNOs to investigate innovative techniques for active network management or 'intelligent' networks in order to maximise the utilisation of existing assets and to defer network investment. For example, in the UK, Ofgem put forward two incentives in 2005 namely the Innovation Funding Incentive (IFI) and Registered Power Zones (RPZ). The IFI funds DNOs for delivering innovative solutions to supply customers effectively and the RPZ scheme promotes DNOs to cut down the costs of reinforcements and connect generation innovatively. As a result, a number of projects have been initiated such as the collaborative Autonomous Regional Active Network Management System (Aura-NMS™) project. The Aura-NMS project encompassed a wide range of control: automatic restoration, steady-state voltage control, power flow management and network losses minimisation [26]. Plans for deploying Aura-NMS were brought up in [27] but none of the controls has been practically implemented up to date. Besides, the robustness of some of the control strategies was yet to be addressed. Some innovative products have also been

[3] DGs normally refer to the generators that are connected to distribution networks.

developed such as the GenAVC™ system that has been applied to a generation project on a UK distribution substation [28]. The RPZ scheme has seen Active Network Management (ANM) systems by Smarter Grid Solutions deployed in Orkney Islands, also known as the Orkney Smart Grid [29]. The Orkney ANM system is deployed to alleviate thermal constraints on local overhead lines and subsea cables so that more renewable generation can be exported. The system has been operational since 2009 and manages more than 20 megawatt (MW) of renewable generation, including a 2MW energy storage system. The deployment of the ANM system to the Orkney Islands is an example of how Smart Grid initiatives (as introduced in section 1.1.4) can be realised in practice.

The deregulation and privatisation of power industries have sharpened the drivers for low costs by virtue of the changes to the business environment. While maintaining a satisfactory quality and safety level of power supply remains the top priority for DNOs, remarkable emphasis is also placed through the Distribution Price Control Review (DPCR) upon the cost-effectiveness of the operation and maintenance of distribution networks by maximising assets' life and usage. As part of the electricity DPCR that runs from April 2010 to March 2015, Ofgem set up a £500m Low Carbon Networks Fund (LCNF) in December 2009 to support a variety of projects to explore innovative technologies and strategies for more effective delivery of energy as GB steps into a low carbon future [30]. Following the LCNF, Ofgem brought forward the RIIO-ED1 price control to set the total revenues that DNOs can gain from consumers as well as the outputs the DNOs are expected to deliver for an extended eight-year period from April 2015 to March 2023. The RIIO framework refers to "Revenue = Incentive + Innovation + Outputs" [31]. The purpose of introducing RIIO-ED1 is to incentivise DNOs to tackle the challenges of providing a low carbon, affordable, sustainable and good quality supply to existing and future consumers [32]. The RIIO-ED1 expects DNOs to economically accommodate low-carbon technologies by moving away from asset investment towards innovative and flexible solutions such as smart grid technologies (as introduced in section 1.1.4) and associated contractual arrangements with consumers and generators.

1.1.4 Smart Grid Initiatives and Technologies

Nowadays, small scaled generation, also known as distributed generation, have been encouraged to connect to existing distribution networks to provide power supply to consumers at locations that are geographically close to load centres so that carbon emissions generated by the conventional combustion of fuels can be reduced. If placed at appropriate locations, DGs have the potential to abate the investment in transmission upgrading. However, the arrangement of DGs' sitting is usually subject to a range of factors such as availability of resources, local network structures and thermal limits of lines or cables. Till this date, it has been under debate whether DGs integration into the existing grid brings more benefit or more challenges.

The growing penetration of intermittent generation in a network has required a revised approach to the traditional mechanisms of controlling the flow of electrical energy. In order to facilitate the operation of the electric grid in an efficient and economic manner while facing a fast-changing energy environment, the concept of a 'Smart Grid' was brought forward by a number of power utilities. Although the concept of 'Smart Grid' is defined differently by utilities in different parts of the world, there are some common features. One of the most widely quoted definitions is outlined as below:

> "A Smart Grid as part of an electricity power system can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies." [33]

The primary objectives of initiating this new concept defined by the Electricity Networks Strategy Group (ENSG) at the UK government forum are to:

- Balance the consumption and production to optimise the output of low carbon sources and integrate intermittent renewable generation
- Reduce the need for network reinforcement in an economic and sustainable manner

Inevitably, the following overarching questions will need to be addressed by any smart grid technology:

- How to accommodate the large volumes of stochastic renewable power
- How to facilitate efficient use of electrical energy through smart devices and technologies such as smart meters
- How to effectively monitor, control and protect the system under all operational scenarios
- How to manage an aging electricity infrastructure and deter network investment
- How to manage the impact of increased use of electricity for heating and transport

These questions highlight the significant challenges facing system operators and network operators. Essentially, the inevitable drive for a prosperous smart grid vision comes from the intention to make effective use of the existing power system assets to meet the changing patterns of generation and demand so that there is less need for costly network investment. The concept of Smart Grid entails that the way distribution networks are managed is expected to change so that electricity can be securely delivered to customers, i.e. the practice of distribution network management needs to embrace innovative and yet feasible strategies. It has also been pointed out that communication and energy management system (EMS) need to be incorporated into the existing DNO systems so as to facilitate the active management of distribution networks [34]. The focus of this thesis is on a strategic control mechanism that aims at improving the management practice at distribution networks. This is further discussed in the following section.

1.2 Scope of This Thesis

In this section, the motivations of the research work and the objectives of the thesis are stated with the proposed methodology introduced. Contributions from this thesis are highlighted and followed by an introduction to each chapter.

1.2.1 Motivations for Research Work

As an important measure of power quality, voltage regulation is one of the top priorities for network operators. In the UK power systems, voltage control methods primarily involve the dispatch of reactive power resources and the settings of voltage control devices such as under-load tap-changing (ULTC) transformers in order to satisfy specific voltage security limits. The technical benefits of effective scheduling of voltage control equipment were identified in [35]; major advantages include the avoidance of large-magnitude voltage fluctuations, savings of reactive power by enhanced utilisation of resources and improved power factors at locations where reactive power is optimally scheduled. In addition to the technical benefits, there are also financial incentives with respect to the operational costs of equipment considering that network assets have limited life expectancy and frequent control operations often bring wear-and-tear to equipment and may shorten preliminary maintenance intervals and even the life expectancy of the equipment.

In addition to the uncertainties in demand profiles, the challenges imposed by increasing renewable generation connected at distribution networks are bringing culture changes within the distribution industry where electricity infrastructure was initially designed to supply demand rather than to accommodate generation. For example, voltage rise issues caused by wind power and photovoltaic (PV) output are especially addressed in [36]–[38]. On the one hand, many of the existing network equipment are about to reach the end of their life expectancy and cost-effective measures are necessary to maximise the utilisation of the existing equipment so that network investment can be deferred. On the other, due to the increased penetration of renewable generation such as wind turbines and solar photo-voltaic cells and their highly variable and stochastic nature as well as uncertainties in demand behaviours, there are increasing risks that the traditional passive way of managing distribution networks will not suffice to maintain desired security levels. In addition, with the implementation of SCADA systems and DMS functions, monitoring and control of loading and voltages in GB systems currently only reach as far as the 33/11kV substations.

At present no measurement is readily available in the low voltage distribution networks where customers are supplied and most DNOs do not have accurate forecast of demand or generation at hand. However, there have been technical and commercial drivers to encourage development on enhanced network management techniques by improving the observability of real-time network conditions and the availability of energy forecast. For instance in the UK, as part of the electricity DPCR that runs from April 2010 to March 2015, Ofgem set up the LCNF in December 2009 to support a variety of projects to explore innovative technologies and strategies for more effective delivery of energy as GB steps into a low carbon future [30]. Some of these projects highlighted the following key objectives:

- Better anticipation of customer demand along feeders by applying forecasting techniques with improved accuracy
- Development of new techniques to mitigate negative impact of increasing DG output
- Optimisation of investment needs of the low voltage networks by identifying where voltage monitoring is necessary

In order to ensure that voltage profiles in a distribution network should not fall outside required tolerance limits while loading conditions and generation levels vary, control engineers need to make effective decisions on which control actions to take at what time. The equipment used at distribution substations for this purpose typically includes ULTC transformers and mechanically switched capacitors (MSCs) at certain voltage levels. In the UK distribution networks, ULTC transformers are used under an automatic network voltage control scheme that regulates the tap changers based on given voltage set points [39]. MSCs normally can very quickly raise voltage profiles by a large step change whilst transformers change voltages by a smaller amount per tap change relatively slowly. Therefore their actions need to be coordinated by operators so that voltage profiles are improved to a satisfactory level. MSCs are generally switched in to respond to large demand changes while ULTC transformers regularly respond to smaller changes in load. Both ULTC transformers and MSCs have limited number of operations during their life expectancy. The cost per control action for these assets may be different and operators also need to take this into account when scheduling control actions so that the existing assets can be utilised to the fullest while the operational cost is reduced.

In particular, target voltages (or set points) for ULTC transformers under automatic voltage control (AVC) schemes are traditionally set to be a fixed value until the supply of electricity cannot be secured due to unforeseen conditions; control engineers then must adjust the set points or operate other control devices; currently, these adjustments are typically made based on engineering intuition and past experience. A constant setting of voltage target may result in frequent control actions at times of highly variable loading conditions which will increase the wear-and-tear on the equipment and incur costs over time in that assets' maintenance intervals and life expectancy will be shortened. Hence, it is of vital importance for control engineers to proactively coordinate control equipment in a reliable and economic manner. The existing control practice to regulate voltages adopted by many DNOs is responsive only after issues are reported. It will be very beneficial for DNOs to have foresight of potential voltage limit violations and to take preventive or corrective actions in advance to avoid non-compliance. Therefore, this work approaches the voltage control problems from an operational planning perspective, aiming at avoiding voltage limit violations and unnecessary control operations.

1.2.2 Thesis Objectives and Methodology

This research work is part of an EPSRC funded programme known as Highly Distributed Energy Future (HiDEF), which is a constituent of the SUPERGEN initiative [40]. The HiDEF programme is focused upon the varieties of expected future distributed power systems that will add to the diversity of energy supply and the capability to accommodate the increasing renewable power penetrations by applying a range of possible system controls [41]. The programme is concerned with the radical changes in the way power systems are structured and regulated owing to the growth of distributed energy resources, with specific investigations on decentralisation in terms of control mechanisms, network infrastructures, market participation and changes in energy policies. The cell concept has been adopted within the programme to envisage the decentralised energy future where the national interconnected power grid is composed of a number of smaller scaled cells. A cell may be regarded as a representation of a small-sized power grid where some of the following participants are involved: generators, customers, network assets and devices, energy storage devices, electric vehicles, network operators, policy makers, retailers and regulators etc.

The work carried out in this thesis lies within Task 2 of Work Stream 2 defined as "Decentralised Control" in the HiDEF programme [41] and the cell considered in this thesis refers to part of an interconnected distribution network with a number of DGs, a variety of loads, a distribution substation including controllable equipment such as ULTC transformers and MSCs. This research project investigates different profiles of demand and generation in distribution networks with particular focus on the quality of supply in terms of voltage variations. It is concerned with the development of smart decentralised control methods to manage voltages from an operational planning perspective for distribution networks. Steady state control strategies for pre-fault configurations amongst the cell's available control devices are explored to minimise voltage violations and reduce control costs whilst diminishing communication necessities.

The objective of this thesis is to develop an effective methodology for controlling voltages in distribution networks in such a manner that the control settings and voltage targets can be scheduled or well-planned for enhanced voltage security and economic operation. The major objectives are to better accommodate the changing loading condition of demand and the availability of stochastic energy sources in distribution networks and to effectively control voltages at various points of the network through efficient management of available control equipment by scheduling control actions or setting appropriate target voltages to minimise the number of control actions over time. The following research questions are tackled in this work:

- How to deal with stochastic generation and demand profiles and obtain good knowledge of voltage performance across distribution networks?

- How to schedule different voltage control mechanisms across a certain time period using available information?
- How to reduce wear and tear on voltage control equipment while respecting requisite voltage limits?

This work seeks to demonstrate that, once available, forecasts of demand and generation within a distribution network can be utilised effectively to keep voltages within acceptable limits making coordinated use of sets of available controls and minimising wear on those controls. In so doing, as well as demonstrating the potential value of such coordinated voltage control, it also serves to show the value of distribution forecasting that is under development in some other projects, e.g. LCNF projects [30], but is outside the scope of this thesis. This thesis proposes a methodology based on the integration of an artificial intelligence planning tool with the power system sensitivity analysis approach. The following tasks are involved to achieve the primary objective of the thesis:

- Appreciation of the significance of voltage control and management in power system operation
- Evaluation of current practical voltage control mechanisms deployed in distribution networks
- Review of existing analytical techniques used for voltage and reactive power control purposes
- Understanding of power system sensitivity analysis in terms of voltage performance
- Investigation of artificial intelligence techniques that may be applicable to resolve voltage control issues
- Development of a control methodology to aid network operators to plan control actions or targets for improved voltage security and reduced operational costs
- Application of the developed methodology to a typical distribution network model under a number of scenarios e.g. winter maximum demand and summer minimum demand

This work aims at improving current voltage control practice in distribution networks by planning day ahead the control settings and voltage targets for controllable devices commonly deployed.

1.2.3 Significant and Original Contributions

The novelty of the methodology proposed in this thesis lies in its capability to schedule control actions on a number of devices within a given period of time on the basis of voltage sensitivity factors and forecasts of demand and generation profiles. The significant contributions from this thesis include:

- an in-depth review of practical state-of-the-art voltage control mechanisms and analytical voltage control techniques,
- a detailed investigation of the artificial intelligence methods commonly used for power system engineering with regard to decision making support for voltage control problems
- a thorough study of power system sensitivity analysis in terms of voltage deviations due to changes in demand and generation profiles.

The major original contributions are:

- the proposal of a methodology for the effective integration of sensitivity analysis in a power system and an artificial intelligence planning approach
- development and demonstration of a novel procedure to automatically schedule voltage control settings for control equipment for a defined time period on the basis of control sensitivities, given time series generation and demand profiles

1.2.4 Thesis Organisation

This thesis is comprised of 7 chapters that are correlated with each other, introduced as below.

Chapter 1 is a general introduction of the research project with regard to its background, motivations, objectives and the original contributions from the research work.

Chapter 2 introduces the operation of distribution networks regarding monitoring and control systems and the major differences between transmission systems and distribution networks. The characteristics of distribution networks including DGs and demand are discussed as well as the practical management of the UK distribution networks. New active management techniques and practical limitations are also identified in this chapter.

Chapter 3 describes the voltage control methods commonly found in distribution networks, especially the transformer AVC control scheme, and the major new voltage control schemes that are commercially available. Cost analysis for major voltage control actions is also included in this chapter as well as the practical challenges imposed by increasing renewable generation.

Chapter 4 presents power system sensitivity analysis which is extensively used in voltage control literatures and a critical literature review of existing publications involving a variety of techniques that have been proposed for voltage control and reactive power dispatch (RRD) problems. These techniques fall into two major categories: conventional optimisation techniques and artificial intelligence (AI) related techniques. Out of these methods, the time interval based methods were critically reviewed.

Chapter 5 is a detailed description of the proposed methodology including a brief introduction to AI planning with discussions on the advantages and potential limitations of the proposed method.

A range of case studies are demonstrated in Chapter 6 to verify the robustness of the proposed methodology and discussions on the results are included for each case scenario. Conclusions are thereby drawn from case studies' results.

Chapter 7 concludes the thesis content, confirms the contributions from this research as well as limitations and also gives recommendations for future work.

1.3 Associated Publications and Presentations

Conference paper, "Voltage Control of a Distribution Network Using an artificial Intelligence Planning Approach", **Jianing Cao**, Keith Bell, Amanda Coles, Andrew Coles, CIRED 2011, Frankfurt, Germany, 4^{th} – 6^{th} June 2011

Conference paper, "Generation Maintenance Scheduling in a Liberalised Electricity Market", **Jianing Cao**, Keith Bell, Ivana Kockar, L.A.S. San Martin, UPEC 2010, Cardiff, UK, 31^{st} August – 3^{rd} September 2010

Conference presentation, "Betterment of Network Performance by means of 'Smarter' Operation", Keith Bell, **Jianing Cao**, IEEE PES Innovative Smart Grid Technologies (ISGT) 2011 Europe, Manchester, UK, 5^{th} – 7^{th} December 2011

Research Project work-stream presentations, "Operational Control of Voltage in Distribution Network", Highly Distributed Energy Future (HiDEF) Workstream 2 general meetings, **Jianing Cao**, various locations in the UK, 2009 – 2012

PhD student research presentation, "Control of Distribution Network with Active Management of Demand", **Jianing Cao**, Keith Bell, DER lab academic seminar, University of Strathclyde, UK, April 2011

Journal under preparation, "Operational Planning of Voltage Control in Distribution Networks", **Jianing Cao**, Keith Bell, Amanda Coles, Andrew Coles, expected for submission: IEEE Transactions on Power Systems

1.4 Summary

In this chapter, the research background has been presented with a focus on the historical development and operation of power systems and the management of distribution systems. As a brief introduction of the research work, motivations, objectives and the original contributions from this thesis have been clearly outlined, followed by a brief summary of each chapter. A list of author's associated publications and presentations has also been included.

This chapter has highlighted that power systems in the UK are developing towards a future with highly distributed renewable generation and growing demand where innovative techniques are required to rise to the emerging challenges. These dramatic evolvements along with the incentives for minimising costs inevitably drive network operators to maximise the usage of their existing assets and to improve their control strategies for managing the transmission and distribution systems.

2. Distribution Network Operation

This chapter introduces the operation of distribution networks regarding the monitoring and control systems and the fundamental characteristics. DG technologies and their impact on the network operating conditions are discussed in this chapter as well as demand characteristics. Existing and new active network management strategies in the domain of distribution networks are presented at the end of the chapter.

2.1 System Monitoring and Control

The operation of power systems is a highly complex task and requires computer-aided tools such as SCADA system and state estimators to monitor and control the operating condition of the systems for improved security and efficiency.

2.1.1 SCADA

SCADA system is an industrial control system that monitors the network conditions by collecting real-time measurement data from remote terminal units (RTUs) at substations and sometimes the remote end of distribution feeders and then supervises and controls power systems at control centres using actuation devices in real time via communication links. The acquired data is communicated and displayed on the master station which enables operators to actuate control tasks remotely. It plays a crucial part in monitoring and controlling system operation conditions. A functional SCADA system normally comprises of the following components: signalling devices, operating equipment such as substation circuit breakers controlled by protective relays, human-machine interface (HMI) at substations, communication equipment, local processors that communicate between instruments and operating equipment such as programming logic controllers (PLCs), RTUs and intelligent electronic devices (IEDs) as well as applications software [42][43]. RTUs are microprocessor-based computers that include digital inputs for equipment status and digital outputs for control actions. Up-to-date monitoring schemes based on telemetry systems can measure and transmit system data including frequency, voltages, currents, power flows, status of switches and transformer tap positions. Such measurements are obtained by SCADA systems in control centres to enable operators to process, display and check the data with required limits for overloads or voltage and frequency violations and to control devices remotely [44].

SCADA systems that are applied in distribution networks are known as SCADA/DMS, also referred to as DNO SCADA in the UK [45]. Figure 2-1 illustrates the major components of a DMS platform with SCADA interface. Topology processors are used to build network models according to the real-time measurements from SCADA system and a state estimator is frequently applied in such systems to obtain the best estimated conditions of power systems.

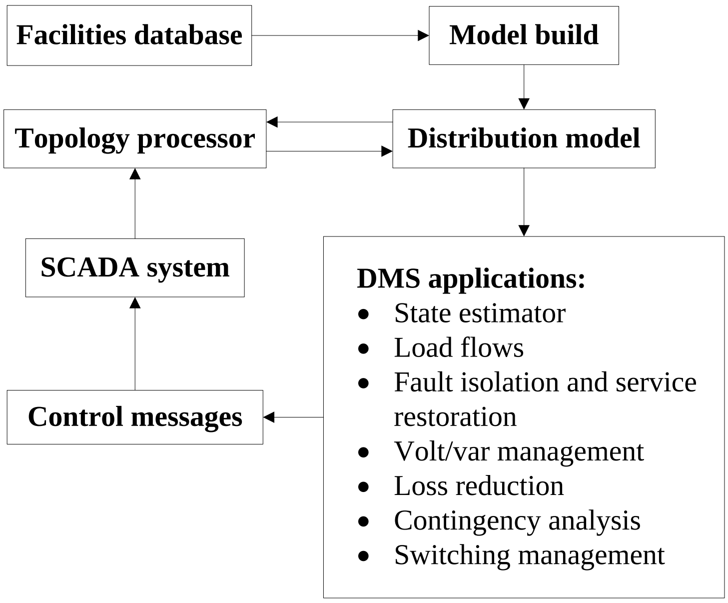

Figure 2-1 SCADA/DMS (adapted from [46][47])

The major advantages of using DNO SCADA systems to actively manage network are listed as below [39]:

- SCADA utilises the existing communications and hardware infrastructure for monitoring and controlling purposes;

- SCADA is dispersed throughout power systems from 400kV HV systems down to 33/11kV substation transformers;
- Software based, SCADA logic can be adaptable and catering to new techniques.

Nonetheless, fundamental limitations of SCADA systems have also been identified with respect to the operation speed, complexity of logic programming and lifetime management of logic configurations etc.

2.1.2 State Estimation

It is important for operators in control rooms to have a relative accurate estimate of the power system status but this is usually difficult when available measurements are imperfect and certain areas do not have measuring devices. State estimation technique is most commonly used to improve the observability of power systems. The technique statistically estimates true values of system parameters by filtering out inaccurate and redundant information from available measurements [48]. State estimation methods represent an electrical network in mathematical models along with state variables including voltage magnitudes at all nodes and phase angles at all nodes but the reference node and the transformer taps. A pivotal step in state estimation is the evaluation of power systems' observability. An observable system should have sufficient real-time measurement available for state variables to be calculated, i.e. the number of parameters to be estimated is greater than or equal to the number of available measurements.

Conversely, inadequate measurement or loss of measurement will lead to an unobservable system, in which case, pseudo measurements are needed to supplement the accessible real time measurement so that the state variables for unobservable part of the network can be estimated. Pseudo measurements are generally more prevalent in distribution systems than in transmission systems due to fewer physical measurements. Pseudo measurements refer to an expected value and the deviation from that value, usually concerning busbar injections and customer load [49]. For instance, active and reactive power outputs from generators are usually measured through telemetry channels; if the telecommunication were failed, inquiries of these values would have been made at control centres directly to the control room of affected power plant and local measurement would be put into the state estimator by hand [48]. Load bus related measurements can be estimated using historical measurements or short-term forecasted load data through many mathematical methods. Once calculated or estimated, pseudo measurements are treated as actual measurements and expressed just as other power flow equations.

Available measurements that might be imperfect or redundant are the inputs to a state estimator and expected outputs are best estimate of the state variables. Due to the inaccuracy and possible redundancy of the available measurement, statistical criterion needs to be satisfied to formulate a "best" estimate of the unknown variables considering the uncertainties. The most commonly used criteria for state estimation include the maximum likelihood criterion and the weighted least-squares criterion. Depending on the use of estimation, a certain degree of error might be acceptable. It was proved in [48] that for measurements from a linear system the maximum likely estimation scheme is equivalent to a least-squares calculation. Owing to the nonlinear relationship between voltages and power though a node, an iterative procedure is applied to minimise the sum of measurement residuals *J(x)* in equation (2-1).

$$\min_{\mathrm{x}} J(x) = \sum_{i=1}^{Nm} \frac{[z_i - f_i(x)]^2}{\sigma_i^2} \tag{2-1}$$

where x is vector of state variables; Z_i is vector of the measurements; $f_i(x)$ is the nonlinear vector function relating power flows through a node to voltages; σ_i^2 is the variance for the i_{th} measurement; N_m is the number of independent measurements.

The process of state estimation in a power system can be summarised as follows: initially voltage magnitudes and angles are set to 1.0 per unit and 0 rad respectively at each node; *J(x)* is calculated and displayed at the start of each iteration; a number of calculations are carried out to solve for ΔX matrix on the basis of H matrix, measurement function coefficient matrix and R matrix, measurement covariance matrix; the maximum Δx_i is found and compared against a set error tolerance limit; the iteration is repeated the error tolerance requirement is respected for the estimated variables.

2.2 Power System Planning

Power system tasks or studies can be summarised in Table 2-1 based on the time scale of studies. As such, power system planning is typically classified into operational, short-term and long-term planning [50].

Table 2-1 Power system studies depending on different time scales (adapted from [48] and [50])

<table>
<tr><th colspan="2">Time Scales</th><th>System studies</th><th>Activities</th></tr>
<tr><td rowspan="4">Operational time scales</td><td>μs-ms</td><td>Transient studies</td><td rowspan="2">0-5secs:
generator automatic voltage regulators (AVRs) and static VAr compensators (SVCs)
5-30secs:
delayed auto-reclose (DAR)</td></tr>
<tr><td>ms-s</td><td>Dynamic studies</td></tr>
<tr><td>s-m</td><td>Automatic generation control (AGC),
Load frequency control (LFC),
tie-line control</td><td>30-180secs:
automatic action phase:
reactive switching & auto tap changer operation</td></tr>
<tr><td>m-hr</td><td>Economic dispatch,
Optimal power flow (OPF)</td><td>3-20mins:
manual action phase</td></tr>
<tr><td rowspan="4">Planning time scales</td><td>hr-days</td><td>Operational planning</td><td>Unit commitment; hydrothermal interchange coordination</td></tr>
<tr><td>Days-weeks</td><td>Short term planning</td><td>Unit commitment; hydrothermal interchange coordination</td></tr>
<tr><td>Weeks-months</td><td rowspan="2">Long term planning</td><td>Maintenance scheduling, power interchange coordination, demand forecast</td></tr>
<tr><td>Months-years</td><td>Maintenance scheduling, fuel scheduling, demand forecast, generation and transmission planning.</td></tr>
</table>

For system planning within days, it is regarded as operational planning; short-term planning typically look into days to weeks and long-term planning is concerned with system development in months and years [50]. Long-term power system planning is concerned with determining strategies to operate power systems so as to meet demand in a reliable manner looking into future scenarios and planning activities include load and generation forecasting, maintenance scheduling, fuel scheduling, reactive power planning (RPP) and system upgrading or expansion [50]. The purpose of short-term and long-term planning is to optimally design or expand power systems to meet the forecasted demand while satisfying technical, economic and environmental constraints. It aims to identify the most effective utilisation of available energy supplies and equipment with regard to their location or point of connection, size and associated costs for the next 1 – 10 years or even longer terms. It is important to note the difference between operational planning and long-term planning: operational planning considers shorter time periods which are closer to real time and requires much greater interaction with on-line system operation whilst long-term planning looks into the coming months or years and is normally off-line and therefore has very little reliance on the real-time system.

Distribution planning looks into distribution networks and associated assets such as DGs, substation transformers, distribution feeders, capacitors and reactors. Activities involved in power system planning [50]. In a centralised electricity industry, power system planning process at its core entails three primary tasks: defining a problem, setting the goals and identifying suitable and effective solutions. However, for a decentralised power industry, each unbundled party makes its own planning decisions but one may influence others to some extent, i.e. generator owners plan their generation expansions on the basis of fuel costs and generators efficiency while owners of transmission and distribution systems plan their networks to cater to anticipated generation or demand developments. RPP is a subset of power system planning and is further described in section 3.3.3.

2.3 Distribution Network

The structure of the conventional UK power systems is shown in Figure 2-2. It can be seen from the figure that, in the UK distribution networks, electricity supply are traditionally delivered from transmission systems via supergrid transformers (SGTs) at Grid Supply Points (GSPs) and steps down voltage levels to meet consumer's demand [51]. Whilst medium-sized and small-sized consumers are generally connected to LV and MV networks, some large industrial consumers may be directly supplied at GSPs.

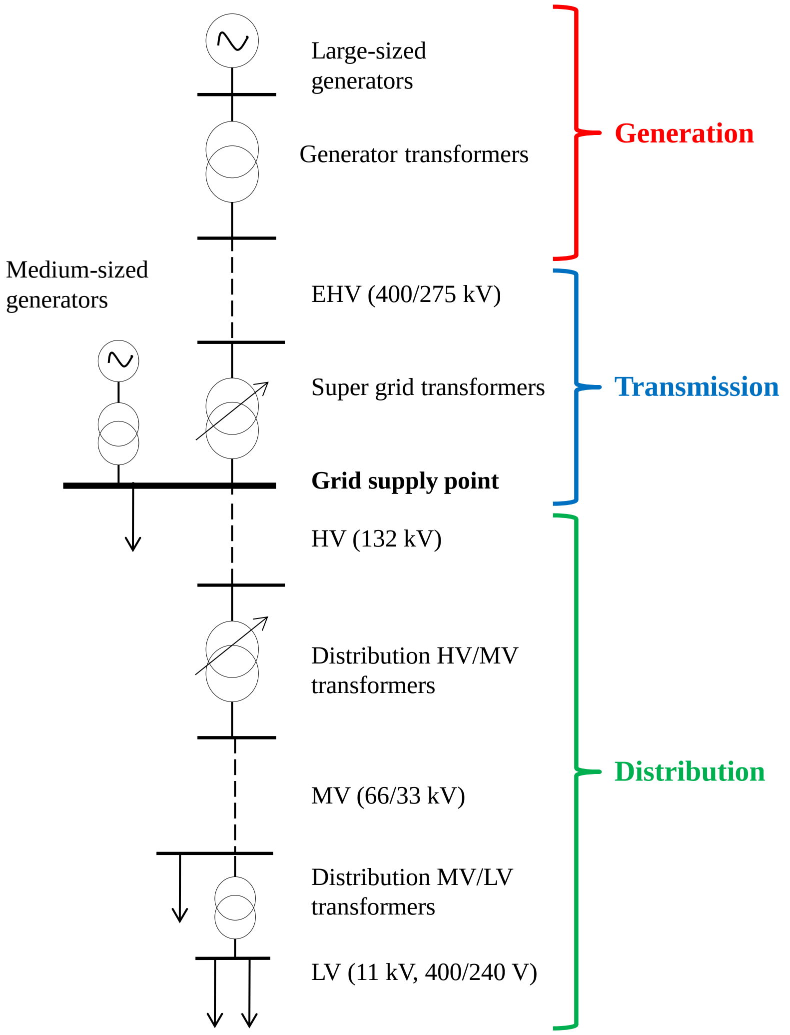

Figure 2-2 Schematic diagram of the UK electricity network structure

2.3.1 Network Characteristics

A typical distribution system primarily comprises of distribution substations, distribution feeders, i.e. underground cables (UGCs) or overhead lines (OHLs), loads and protection devices such as circuit breakers [51]. Distribution systems are characterised by voltage levels, network configurations as well as the density and types of loads. In the UK, voltage levels in distribution systems are typically categorised into LV, MV and HV levels, as shown in Figure 2-2.[4] Voltages are stepped down from HV to MV at primary substations and from MV to LV at secondary substations [52]. The three common configurations in distribution systems are radial, open loop, mesh and interconnected network configurations [51], as described in Table 2-2 and depicted in Figure 2-3. Radial arrangement is the simplest to deploy and the least expensive configuration, because no redundancy or sectionalising is required [53]. Open-loop arrangement has normally open points (NOPs) to isolate faulted equipment and to restore supply via alternative circuits. However, the configuration is more complicated to operate and needs more circuit breakers and protection schemes [53]. Owing to the circuit redundancy, open-loop arrangement is often applied to underground distribution in urban areas since supplies in intact parts of the network will not be interrupted [53].

Table 2-2 Distribution network configurations and characteristics ([51])

Voltage levels	***Typical configurations***	***Characteristics***
HV	Interconnected arrangement: mesh/ring configurations	Maintains a good level of security for supplying power; needs a good number of circuit breakers
MV/LV	Open-loop arrangement	Once fault is isolated, normally open points (NOP) can be closed to restore power supplies
LV	Radial arrangement	Least geographically determined, fewer plant equipment required

[4] However, a particular voltage level may be defined differently in different areas. For instance, in the UK power systems, the voltage of 132kV is considered as distribution in England and Wales but classified as transmission in Scotland.

The configuration of distribution networks is fundamentally designed on the basis of load characteristics such as density, peak demand, geographical distance from the transmission systems and voltage levels [51]. These characteristics naturally classify distribution networks as urban, rural, suburban or industrial areas. For instance, urban distribution networks tend to be mapped with a high density of loads while rural networks are inclined to have a lower density of loads that are scattered throughout an area. Amongst the three configurations, radial arrangement is commonly used in rural and suburban areas while meshed network in urban areas. In the UK, urban areas usually feature short distance underground cables and ground-mounted distribution substations with transformers rated from 500 kVA to 750 kVA. Rural areas have relatively longer overhead lines with pole-mounted transformers rated from 25 kVA to 200 kVA [54].

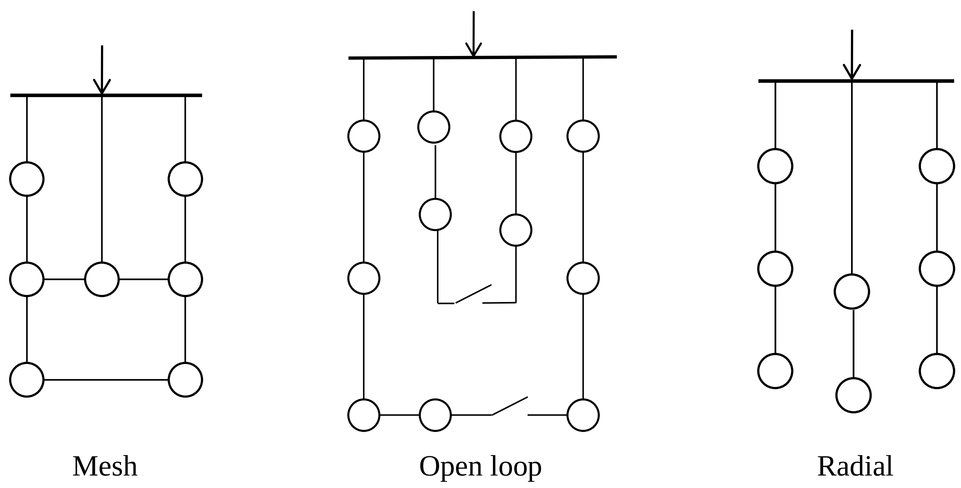

Figure 2-3 Different distribution system configurations (adapted from [51]) [5]

2.3.2 Changes in Network Conditions

Without the presence of distributed generation, distribution networks are traditionally centrally supplied by large power plants from the transmission system in a single direction, illustrated in Figure 2-2, where electricity is supplied to domestic

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[5] Circles in this figure represent busbars and switches represent normal open points which are open during normal operating conditions and closed for system restoration upon fault occurrence.

consumers with unidirectional power flow [55]. The increasing penetration of power generated by renewable energy resources located in distribution networks has resulted in changes in the direction of power flows, i.e. conventional unidirectional power flows have become bidirectional [55]. An example of a distribution network with the presence of DGs is depicted in Figure 2-4.

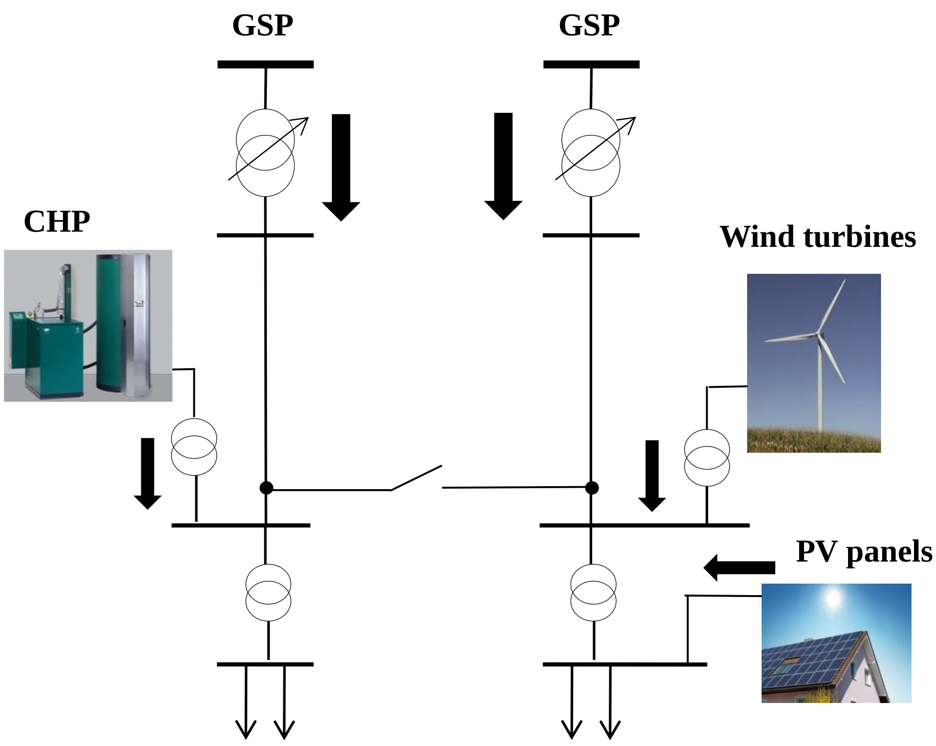


Figure 2-4 Distribution Network with DGs

Conventionally, the distribution networks are designed to cater to the forecasted maximum demand [39]. As the number of DGs grows, the conventional configurations may not be capable of fully utilising DGs' output. For instance, the outputs from relatively large-sized DGs may need to be curtailed to avoid exceeding the thermal limits of the local lines in [56] or because of violations to voltage limits in [57]. In brief, the growing number of connected DGs is driving rapid development in control and communications within distribution networks to cope with emerging operational issues faced by network operators such as voltage rise problems, increase in network fault levels, overloaded feeders and stability issues induced by uncertain power output [55].

2.3.3 Differences between Transmission and Distribution Systems

Distribution systems inherently differ from transmission systems in a number of aspects and the primary differences are summarised in Table 2-3. [6]

It can be summarised from this table that distribution networks differ from transmission systems in a variety of aspects. Compared with distribution networks, there is a smaller number of equipment in transmission systems but many of the equipment used in transmission systems can be highly complex such as flexible AC transmission system (FACTS) devices. On the other, a failure of one piece of equipment at transmission systems may result in blackout in affected areas or even the collapse of the entire system whereas the loss of an equipment in distribution network is likely to affect a relatively smaller number of consumers, which is one of the important reasons why transmission systems are highly interconnected. Electricity transmission and distribution systems are normally required to meet different standards due to the difference in network configurations and physical characteristics. In the UK, the operation of transmission systems should conform to SQSS [17] and the Grid Code [18] whilst the operation of distribution networks should comply with the Distribution Code [19].

The management of distribution networks has to change in order to respond to the growing DG penetration and increasing and potentially flexible demand pattern. Unlike the conventional passive operating conditions, distribution networks with DGs and responsive demand have made active decision making tools more appealing than before. The management of distribution networks is likely to require some methods that have so far only been used for transmission systems but the applicability needs to be evaluated and verified.

[6] The differences in protections schemes applied in transmission and distribution systems are not listed in this table since the topic is beyond the scope of this thesis.

Table 2-3 Differences between transmission systems and distribution systems ([2], [34], [51],[58],[59])

Aspects	***Transmission systems***	***Distribution systems***
Design and configurations	Highly interconnected and complex	Different configurations depending on geographical conditions and voltage levels: radial structures at MW and below
Physical characteristics	OHL: Long distance; High X/R ratio A relatively smaller number of system assets with a high proportion of FACTS devices Low power losses (2% of total energy generated)	UGC & OHL: Short distance; Low X/R ratio A relatively greater number of system assets with less varieties High power losses (8% of total energy generated)
Network operators, standards and major responsibilities	SOs: Grid Code, SQSS Instantaneously balance demand and generation; Design, operate and maintain transmission systems; Provide connections to owners of large-sized generator; Secure sources of reserve and auxiliary services	DNOs: Distribution Code, Electricity Supply Quality and Continuity Regulations, Engineering Recommendations Design and maintain distribution systems; Ensure a satisfactory level of equality of supply; Minimise the negative effect of any equipment failure; Provide secure connections to electricity users and suppliers
Security	Secured against N-1 and N-D conditions in system planning	"Fit-and-forget" approach [60]
Operating characteristics	Dynamic system with generation availability, network constraints, varying load and intermittent renewable generation	Passive system with distributed loads and little generation to manage, or, active system with bidirectional flows with the existence of many DGs
Management and control practices	Application of SCADA and EMS in control centres and transmission substations throughout the system	Application of SCADA/DNO systems at distribution substations above 33/11kV
	Constraint management, reserve management, risk management of outages, demand forecast etc.	Manual operation of certain assets in LV networks such as transformers and lack of monitoring devices at LV networks
	Replacement of network assets are planned in advance to avoid un-repairable failure or uneconomic indication	Replacement of network assets usually takes place after the report of failure

TSOs are presented with challenges such as increasing demand, aging assets, growth in renewable generation, uncertainty in the nature of demand, and accurate forecast of demand and system conditions from a real-time point of view and from the long-term planning perspective. DNOs' challenges are more centred around the utilisation of aging assets and the operational management of DG related issues such as bidirectional load flows, voltage levels and fault levels due to growing DG penetration. These challenges are gearing DNOs to move towards active management practices with emphasis on decision-making strategies regarding the coordination of local control targets and settings.

2.3.4 Distributed Generation

As stated in Chapter 1, since last decade, renewable generation has been promoted across the globe to supply electricity demand, aiming at reducing the carbon emissions generated from conventional generators and losses dissipated during long distance electricity transmissions and supporting MV and LV network locally [55].[7]

2.3.4.1 Definitions

The definitions of distributed generation are inconsistent in existing literatures but a common definition is:

> "Distributed generation (also known as embedded generation) refers to small-scale generating units that are directly connected to distribution networks that supply consumers on-site [55]. "

Compared to the above definition, the one given by Ofgem is simpler:

> "Distributed generation is the electricity generation connected to the distribution network other than the transmission network [61]."

[7] There has historically been some controversy about the 'carbon cost' of manufacturer of distributed generators and how much time in operation (and the associated displacement of carbon from other generation sources) it takes for it to be paid back.

Other examples of definitions of distributed generation can be found in [62]. In this thesis, the definition by Ofgem is used throughout.

2.3.4.2 Technologies

There are two major types of DGs, one operated for self-supply purposes, mainly in the form of CHP or PV systems, the other used to supply third parties from renewable energy resources such as wind and hydro power [63]. CHP plants namely supply both heat and electrical power to close-by consumers such as large-sized industries; a CHP plant can be fuelled by gas, coal, oil or in some cases, biomass. Renewable generation refers to various sustainable energy resources such as wind, biomass, wave, hydro and solar power. Technologies associated with DGs include wind turbines, PV systems, fuel cells, small and micro turbines, internal combustion (IC) engines and micro hydro schemes [64]. These most commonly applied DG technologies are summarised in Table 2-4.

Table 2-4 Summary of major DG technologies ([64][62])

DGs	*Techniques*	*Size range*	*Overall efficiency*
CHP	IC engines	5kW−10MW	35%
	Micro turbines	25kW−25MW	29%−42%
	Gas turbines	1−20MW	21−40%
	Fuel cells	200kW – 2MW	40−60%
Hydro power plants	Micro/Small hydro	25kW−100MW	Not applicable
Wind farms	Wind turbines (offshore/onshore)	200W−3MW	Not applicable
PV systems	PV panels	1kW – 1MW	6−19%

Wind farms can be categorised into onshore and offshore types. According to the UK wind energy database (UKWED), currently the capacity of operational onshore and offshore wind farms is 5,028 MW and 2,362 MW respectively [65]. Specifically, about 63% of onshore wind farms in the UK are in Scotland and about 93% of offshore wind farms are in England.

2.3.4.3 Characteristics

DGs are normally connected into distribution networks at GSPs, at primary or secondary substations or directly at consumer sites. The choice of whether to invest in DGs is primarily dependent on the purpose, location, fuel/resource availability, environmental conditions and acquired space and equipment as well as maintenance effort [66]. DGs relying on renewable energy resources share some similar characteristics such as their volatility and unpredictability.

Table 2-5 gives a concise list of the features of different types of DGs. Examples of daily output patterns of a wind turbine, a CHP plant and a PV generator on a half-an-hour basis were illustrated in Figure 2-5. The wind power output shown in the figure was obtained at a UK wind generation site on a winter day in January by the courtesy of Dr Thipnatee Sansawatt in SPEN and it can be seen that the output is highly variable during the course of a day. The power output of a CHP plant is supposed to provide reliable heat and power to consumers, thus its output follows a relatively predictable output pattern (full output during daytime and minimum output during night-time). The CHP output pattern from reference [67] was shown in this figure. The output of a PV generator is reliant on the solar radiation and temperature; on a typical summer day on the northern globe, the power output of a PV generator reaches its peak value around midday. The time series PV profile shown in the figure was derived from reference [68].

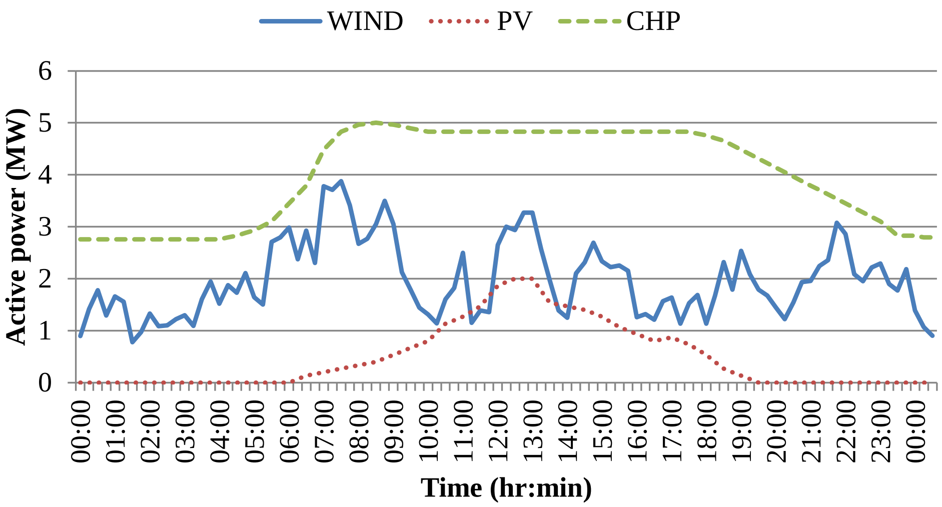


Figure 2-5 Daily time series output profiles for different types of DGs

Table 2-5 Features of different types of DGs ([64], [66], [69],[70])

DG types	*Characteristics of generation*
PV Systems	• No fuel costs • Similar seasonal profiles • Weather dependent (temperature, sun radiation, cloud dispatch etc.) – only generate power when sun radiation and temperature reach a certain level • Power generation process is carbon emission free and noise free • High investment costs on solar panels • Connected to grid using power electronics interfaces DC/AC
Wind power	• No fuel costs • Intermittent generation, closely related to wind speed – no generation when the wind stops blowing • Very expensive investment costs on blades and very high maintenance costs, particularly for off-shore wind farms • Connected to grid using electrical generators (synchronous generators or induction generators) or power electronic interfaces AC/AC
Fuel cells	• The use of a variety of fuels of such as natural gas and landfill gas to produce hydrogen-rich gas • Conversion of hydrogen and oxygen into electricity, heat and water • Attention needs to be paid on safety issues regarding the hydrogen generation process • Highly expensive investment costs • Environmentally friendly – no carbon emissions during power generation process; no moving parts, i.e. very low noise • Connected to grid using power electronics interface DC/AC • Well suited to CHP applications
Hydro power	• No fuel costs • Power generation closely related to the speed of water flow which is highly variable (related to weather conditions such as rainfalls) • Storage capacity may be necessary to reduce great fluctuations in available water flows • Output characteristics depend on the area of land where water is aggregated • Connected to grid using synchronous generators

2.3.4.4 Connections

The type of grid connection depends on the type of primary energy resources and available technologies. DGs can be connected to the grid through synchronous machines, induction machines or power electronic interfaces. The relationship between different connection technologies and DG types is shown in Table 2-6. The advantage of using synchronous generators to convert original form of energy into AC power is that the output can be regulated to provide reactive power support. The same holds for connections via power electronic converters [69].

Table 2-6 DG grid connections and relevant technologies ([66])

DG connections	***Major DG types that can be connected***
Synchronous generators	IC engines, gas turbines, solar thermal, geothermal and biomass, small-scale hydro plants
Induction generators	Wind turbines, micro hydro power plants
Power electronic interfaces	PV systems, CHP, fuel cell, micro-turbines, wind turbines

Regarding the point of connection for renewable generators, key factors involve the size of the generating units and the capacity of local distribution networks or transmission systems. Developers of small-sized DGs such as domestic PV systems are apt to connect to the nearest local network point from generating sites; developers of medium-sized and large-sized renewable generators such as wind farms may have to be connected to transmission systems to avoid violating the thermal limits of local distribution feeders [62]. In the UK, connection requirements for large or medium sized generators that are powered by intermittent power sources are specified in the Grid Code.[8] As for such generators in distribution networks, the Energy Networks Association (ENA) has set out three connection guides/recommendations (shown in Table 2-11) for owners or developers of small DGs on the basis of the size of DGs, voltage level of connection and the number of generating units (known as the Decision Tree for the Distributed Generation Connection Guide) [71]. The

[8] In the Grid Code, the term Power Park Modules is defined referring to onshore and offshore generating units powered by intermittent power source that are connected to onshore and offshore transmission systems via a system with a single electrical point.

obligations on DGs such as the exchange of data are specified in the Distribution Code. In particular, owners of DG units are required to reach a Connection Agreement with the DNOs, which spells out the operational requirements on generators [39], e.g. limits of terminal voltage, net import and export capability (active and reactive power) and operating power factor etc.

2.3.4.5 Forecasting

Unlike the conventional thermal power plants whose outputs can be regulated according to the owners' requirement, generators depending on renewable energy resources are typically stochastic and highly intermittent, which inevitably imposes risks to the quality of power supply [72]. As a consequence, accurate forecasting of the output from these generators is important for the owners/developers as well as the network operators to maintain a good level of power quality. For DG owners/developers, accurate forecasts of the DG output can enable them to optimise their operational strategy and financial benefit. The trading of electricity in a liberalised electricity market typically penalises unpredictable power generation and the increase in forecast accuracy is essential for reducing such penalties and maximising revenue [73]. The cost associated with wind generation prediction errors is especially assessed in [74] under a liberalised electricity market. For SOs, forecasts of such generation can help to facilitate adequate planning of power systems because they can be used to balance the fluctuations in renewable generation using other forms of energy to meet specific demand [75]. In particular, short-term generation forecasts play an important part in ensuring the balance between generation and demand, i.e. maintaining the secure and economic operation of the system through generation maintenance planning, arranging sufficient operating reserve etc. Examples of weather-driven techniques used for day-ahead forecasting of wind power and PV power can be found in [72] and [76] respectively.

Notably, a number of forecasting systems have been investigated in many countries, which are normally based on local weather forecasts and wind farm topology etc. The state-of-the-art of the modelling techniques used for short-term predictions of wind power applied in Europe and the United States can be found in [77] and [78] respectively. Widely popular forecasting models include time series models based on neural networks and numerical weather prediction-based models. A review of diverse models used for wind power forecasting can be found in [79]. In the UK power exchange market (where trading is inclined to occur in the last 24 hours ahead of real time), the ROC and the market clearing price constitute the total price of the electricity generated by renewable resources. Under this context, the accuracy of short-term generation forecasts has a predominant effect on the economic benefit that the generator owners can gain [75]. As part of the System Operator External Incentive Plan, the NGET also proposed a renewable generation forecast incentive, which aims at reducing day-ahead wind forecasting error [80]. It is anticipated that the wind power deviation will be reduced to 30% over 4 hours by 2020 by using improved forecasting models [34].

2.3.4.6 Impacts of DGs on Distribution Networks

DGs were initially introduced to power grid because of their much smaller or negligible carbon emissions during the power generation process, yet their integration to the grid needs to be done with care. For instance, the building of wind farms is subject to a range of evaluations such as wind turbines' visual impact and noise emissions when rotating [81]. The potential technical and economic impacts of DGs have been extensively investigated in literatures since their introduction. For example, the impact of PV power generation on rural distribution networks is investigated in [82]. The penetration of wind power into power systems may raise questions regarding the adequacy of existing transmission and distribution systems and possible requirement for transmission investment, as addressed in [83]. Power penetration from wind farms connected to transmission systems entails a number of technical issues. For instance, the intermittent wind power may exert unanticipated load on transmission lines at local transmission areas where power is delivered from the generation site to interconnected systems. A recent method was proposed to evaluate the required transmission connection capacity under such circumstances in [84]. Table 2-7 shows a concise summary of DGs potential benefits and issues that has been identified in the existing publications.

Table 2-7 Potential benefits and issues with DG penetration ([62][25][69])

	Potential impacts on networks	

Technical	*Benefits*
	• Possible peak shaving of demand when loading is high
	• Diversification of energy resources
	• Reduction on transmission losses
	• Less stress on transmission loadability with appropriate output
	• Enhanced reliability by virtue of provision of local support
	• Provision of grid support such as ancillary services
		Issues
		• Changes to network voltage drop
		• Increase in network fault levels
		• Reversed power flow
		    o exceeding thermal limits of lines
		• Decrease in the level of power quality
		    o Transient voltage variations
		    o Harmonic distortion of voltages
		    o System frequency deviations
		• Uncertainties in network operation conditions
		• Negative impact on existing protection schemes

Commercial	*Benefits*
	• Positive impact on market activities
	    o Deregulation or competition policy
	    o Flexibility in price response
	• Financial incentives to developers of renewable technologies
	    o e.g. the ROs and the FITS in the UK electricity market
	• Reduction of system costs
	    o Alternative to grid investments
	        • Deferments of network infrastructure upgrade
	        • Substitution for system expansion or upgrade
		Issues
		• High financial investment and maintenance costs
		• Increase in electricity bills for customers that do not own DGs, especially when financial support from government is necessary
		• Depending on the size and location, requirement of investment for network reinforcement to accommodate DGs' capacity

As mentioned before, since DGs relying on renewable resources cannot decide their outputs in advance and may curtail power outputs relative to the available power, the impact from the increasing penetration of DGs to the existing distribution networks may result in undesired network conditions with respect to voltage issues and increased fault levels [25]. Specifically, power flows and voltage profiles are subject to unanticipated changes depending upon the operating conditions of distribution systems and DGs' inherent characteristics. DGs need to be sited at appropriate locations to generate a requisite amount of power while being controllable in order to cater to changing network operating conditions. The following factors are crucial in determining voltage profiles for a distribution network integrated with DGs [85]:

- Capacity and location of DGs
- Voltage regulator settings/reactive power capability of DGs
- DGs output profiles in time series
- Characteristics of close-by loads regarding size and time series profile
- Impedance characteristics of the local lines or cables

2.4 Load Modelling and Characteristics

In the power system context, demand refers to the energy consumption by electricity users such as individual household users and industrial plants; electricity demand can be measured at some customers' sites via electricity meters or at power substations at transmission or distribution level using monitoring devices [51].

2.4.1 Load Models

For a busbar connected with motors and other rotating machines, a general representation of the load is the apparent power S consumed by demand, regardless of voltage levels [2]. Power factors are often stated with the S load, specifying the relationship between active power P and reactive power Q. Two other models include impedance load and current load: the power S of an impedance load is proportional to the square of voltage while the power S of a current load is proportional to voltage. The impedance load typically represents loads like incandescent lighting and resistive heating while the current load is useful for rectifier load and certain types of synchronous machines. There are broadly two types of load models: static and dynamic. In particular, loads can be modelled as linear functions of voltage to certain exponent, depending on the type of model [2]. Since it is not the focus of this thesis to discuss load modelling, only static models of load dependent on voltage are introduced in this section. The exponential load model with respect to voltage is shown as below:

$$P = P_o\left(\frac{V}{V_o}\right)^a \qquad Q = Q_o\left(\frac{V}{V_o}\right)^b \tag{2-2}$$

where P and Q are the active and reactive power consumed by the load with the voltage at the busbar being V. The subscript o represents the initial conditions of the variables. With the exponents a and b assigned with different values, these equations can represent one prominent nature of the load: the values of 0, 1 and 2 indicate constant power, constant current and constant impedance load respectively. In case studies carried out in this thesis, it is assumed that all the instantaneous loads are of constant power type.

2.4.2 Demand Types and Load Profiling

Demand consumed at different levels of power systems has different characteristics. Typically the electricity usage of an individual household is subject to uncertainties and hence the fluctuations in loading tend to be volatile and sharp. The measured loading condition at substations tends to be relatively smoother in its pattern since it is an overall aggregation of the loading from connected components such as a cluster of individual loads, DGs, lines/cables and transformers. Therefore, it is sensible to analyse load at consumers' level for detailed distribution system studies and analyse the loading trend recorded at distribution and distribution substations for wider system studies.

2.4.2.1 System Load

At transmission levels, measured daily demand at transmission substations tends to demonstrate a similar seasonal pattern throughout a year, though at different levels. This can be observed from Figure 2-6, where the overall trend for electricity consumption in a typical day presents a degree of likeness [6].

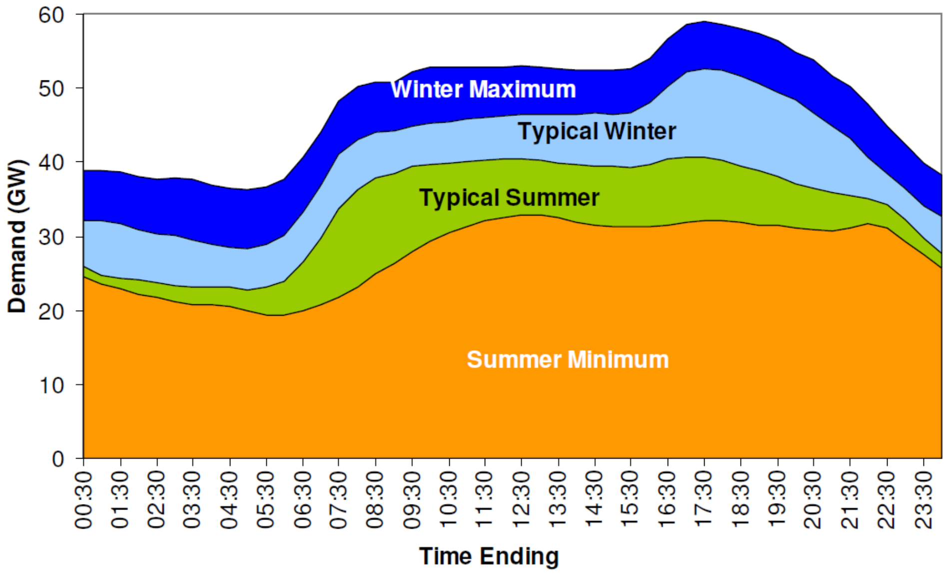


Figure 2-6 Seasonal daily demand profiles in the UK 2010/11 ([6])

The demand profiles in Figure 2-6 also indicate that the value of maximum demand experienced in winter in GB at around 17:30 on a weekday, can be about three times higher that of summer minimum demand which occurred at around 06:00. Historical data has also suggested that the maximum demand is more likely to occur on one of the weekdays in mid-winter while the minimum tends to occur on a weekend day in summer depending on the intensity of activities that consume electricity [52]. [9]

In the UK, the total demand was 376,241 GWh in 2012; the make-up of demand is shown in the pie chart in Figure 2-7 [86]. Amongst the sectors, domestic, industry and commercial demand accounted for 30%, 26%, 21% respectively, taking up the majority of electricity supply; losses and fuel industries each take up 8% of the total

[9] The peak and minimum demand tends to occur at different seasons at different parts of the globe. In this thesis, situations in the UK were considered.

demand; the rest is consumed by public administration, transport and agriculture. Compared to the statistics in 2011, the domestic consumption rose by 2.8% due to relatively colder temperatures in winter and commercial consumption also increased by 0.9% [86].

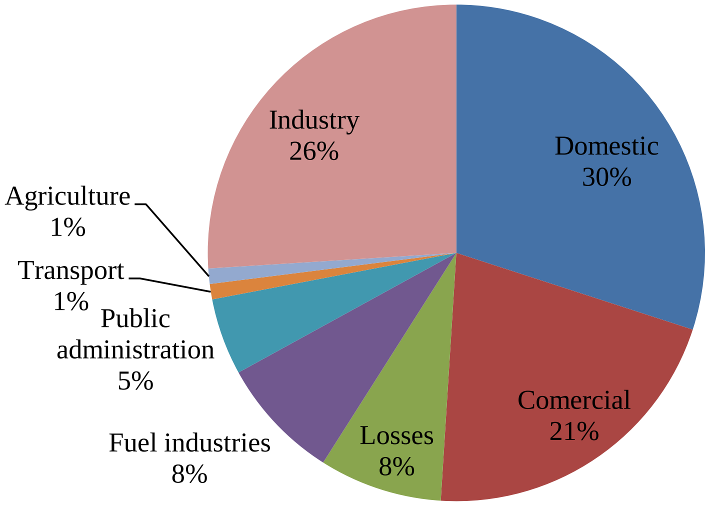


Figure 2-7 UK demand for electrical energy by sector in 2012 ([86])

2.4.2.2 Consumer Load

Load characteristics lie on the natural of the use of electricity; load can be broadly categorised into domestic and non-domestic load [87]. Non-domestic demand include commercial and industrial load, described in Table 2-8.

Table 2-8 Types of load ([2][87])

	Customer Type	***Examples***	***Load range***	***Voltage levels (UK)***
Domestic demand	Residential	Urban, suburban: hotels, apartments, flats/houses	<100kW	400/230V
		Rural: farms, houses,		
Non-domestic demand	Commercial	Department stores, office buildings, service centres, hospitals, schools	100kW-4MW	11kV
	Industrial	Manufacturing factories, enterprises (chemical, paper and food)	> 4MW	132/33kV

The Energy Networks Association (ENA) grouped standardised consumer demand profiles into eight classifications, outlined in Table 2-9. [10]

Table 2-9 Customer usage profile classes ([88])

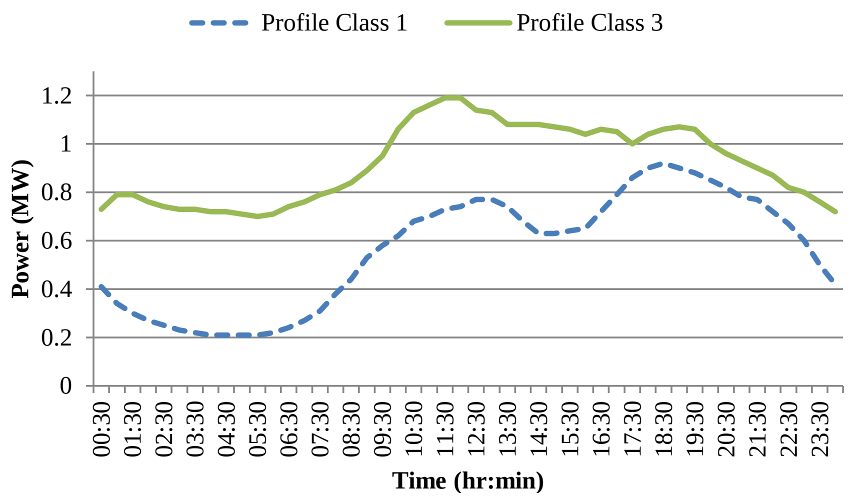
Profile	PROFILE DESCRIPTIONS
Class 1	Domestic Unrestricted Customers
Class 2	Domestic Economy seven Customers
Class 3	Non-Domestic Unrestricted Customers
Class 4	Non-Domestic Economy seven Customers
Class 5	Non-Domestic Maximum Demand (MD) Customers with Load Factor 0-20%
Class 6	Non-Domestic MD Customers with Load Factor 20-30%
Class 7	Non-Domestic MD Customers with Load Factor 30-40%
Class 8	Non-Domestic MD Customers with Load Factor >40%

Energy consumers were generally divided into two groups, unrestricted and economy seven customers [88]. Unrestricted customers refer to users charged by a single rate for consumed electricity; economy seven customers refer to users in the electricity tariff with variable prices depending upon time of a day, usually at two rates, a higher one for daytime use and a lower one for night-time use of electricity. Maximum Demand Customers refer to the consumers whose metering system has a register that records the maximum demand for a specific time period. The load factor refers to the ratio (expressed as a percentage), of the number of KWh supplied during a certain time period to the number of KWh that would have been supplied if the maximum demand had sustained throughout the period. A higher load factor generally means more electricity consumption.

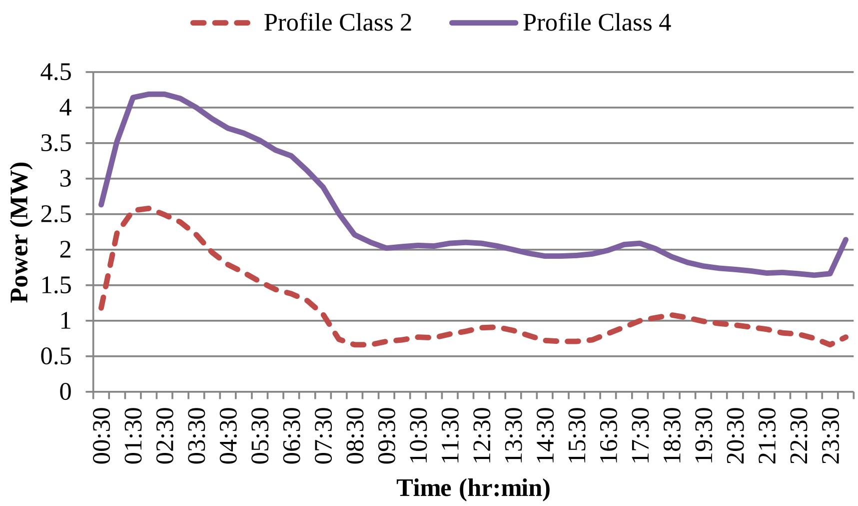
Loading conditions at consumers' sites vary throughout a day and over the seasons. In the UK, on an annual basis, peak demand typically takes place on weekdays during winter when the temperature is low and electricity heating is greatly needed; minimum demand is prone to be on weekends in summer at times of moderate ambient temperature and space heating is not required [52]. Load profiles refer to different types of load data on half-an-hour or hourly basis for a relatively long time

[10] ENA was previously known as the Electricity Association.

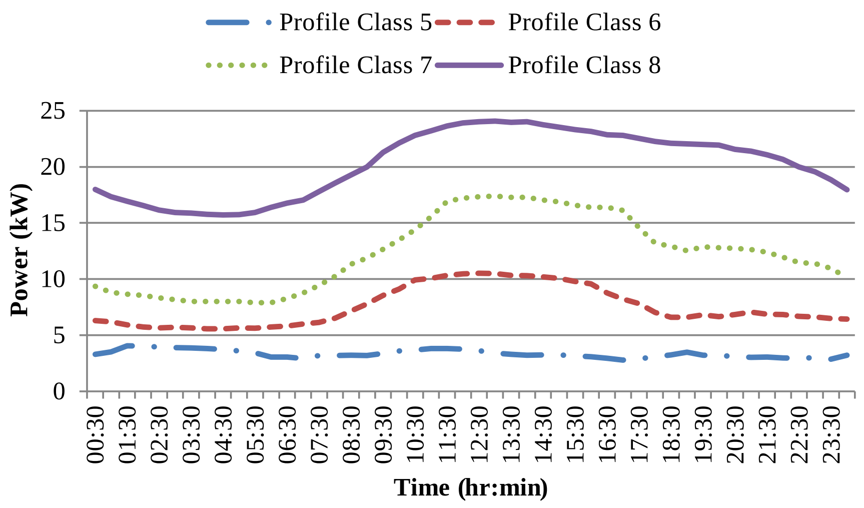
period, usually one day or longer; these profiles indicate the time-varying pattern of the use of electricity [88]. In order to illustrate how different customers typically use electricity during the course of a day, Figure 2-8 is included showing the historical loading profiles for all the demand classes measured on a Wednesday in a typical winter [88]. The plots in (a) and (b) indicate that normal unrestricted customers (Class 1&3) tend to use more electricity during mid-day and evenings whereas economy 7 users (Class 2&4) are more likely to consumer more power after midnight until 8am. The figure in (c) suggests that the higher the load factor, the greater the average power consumed. The electricity usage patterns also indicate that non-domestic MD customers are liable to consumer more power from 9am to 5pm.



(a) Unrestricted customers



(b) Economy seven customers



(c) Non-domestic maximum demand customers

Figure 2-8 Daily demand profiles for a typical winter Wednesday ([88])

2.4.3 Load Uncertainties and Forecasting

Considering that loading conditions in distribution and transmission systems can change expectedly or unexpectedly by large scales and that these changes can lead to undesired system conditions if not managed with matching supplies, SOs need to forecast, manage and plan for demand fluctuations in order to prevent possible undesired voltage excursions [89]. Electricity demand is normally nonlinear and stochastic. The magnitude and time of occurrence of maximum demand are subject to weather, fuel costs, holiday times, social or sports events and business environment [90]. In particular, temperature and daylight affects heating and lighting load respectively. Weather factors primarily include the ambient temperature, humidity and wind speed. For domestic demand, peak demand is likely to occur at times of breaks for popular television events e.g. soaps or international games or matches when customers tend to use electricity for household appliances; electricity usage during this time period can be as much as 10% more than the normal demand. Key factors that are strongly related to demand fluctuations include weather forecasts and historical data. In brief, demand forecast is subject to the following major uncertainties: time varying weather conditions, economy trends, energy efficiency of electric appliances, demand response from certain customers and mobile electric vehicles [91].

Accurate prediction of energy customers' load is necessary to enable the day-to-day operation and planning activities [92]. Load forecast is categorised into three major types: short-term, mid-term and long-term forecasts. Short-term forecasts refer to hourly prediction of demand for a lead time of an hour up to several weeks and plays a vital part in facilitating secure and economic operation of power systems; mid-term forecasts refer to hourly or peak load predictions from a few months to a few years ahead and is especially important for system planning; long-term forecasts are concerned about demand from a few years onwards and is essential for system planning and investment [92][89].

Since one of the assumptions in this thesis is that day-ahead demand forecasts are credible, short-term demand forecasting is discussed here. The economic operation of power utilities is influenced to a large extent by the quality of short-term demand forecasts due to their economic implications. In EMS at control centres, results of short-term forecasts are typically used in economic dispatch, unit commitment and energy trading and other power system studies [93][94]. A range of techniques have been developed by researchers for short-term load forecasts, mainly involving statistical methods and AI-related approaches. Statistical methods, developed in the early 60s [95], use mathematical models and weather data for demand-related variables to obtain forecasted values [96], such as regression based method in [97], time series approach in [98] and autoregressive model based methods in [99]. AI-related methods have gained a lot of attention since early 90s and take advantage of operators' experiences and expertise to estimate loads, such as fuzzy expert systems in [100], knowledge-based systems in [101], artificial neural networks (ANN) in [102] and their hybrid models in [103].

To many power utilities, accurate predictions of demand is of vital importance in that overestimation of demand will give rise to operation of unnecessary generating units or excessive purchase of electricity while underestimation will lead to inadequate supply, both jeopardising the security and cost effectiveness of power systems [104]. As techniques used for load forecasting have matured remarkably in recent years and predicted demand has become increasingly unbiased and more precise, some utilities have implemented short-term load forecasting systems in their EMS; relevant examples over the years can be found in [105][106][107][104][108].

In the UK, electricity demand forecasting at transmission systems has been one of the primary responsibilities of the SO (NGET) [109] for a range of beneficial reasons as mentioned in previous paragraphs. Traditionally, distribution networks were designed to accommodate demand and load forecasting at distribution networks was not a top priority for DNOs since their major responsibility was to maintain and operate the distribution networks without any involvement in energy trading, i.e. no requirement to do economic dispatch activities etc. Yet in these days, load forecasting is gaining more attention as one of the active management solutions that may be potentially implemented in the existing SCADA system [39]. This is an outcome of the driver to improve the reliability of network operations by knowing in advance how demand will vary. In addition, as mentioned in chapter 1, distribution load forecasting have been addressed by some LCNF projects currently in progress such as the “New Thames Valley Vision: From data to decisions” by Southern Electric Power Distribution [30].

2.4.4 Demand Side Management

The desire to enhance the efficiency of power system operations has been one of the fundamental drivers besides the deregulation of electricity market for introducing demand side management (DSM) programmes [110]. DSM programmes are concerned with techniques or schemes intended to lower peak demand or alter electricity consumers’ usage pattern so as to match power generation with consumption. If deployed, DSM programmes may be able to mitigate voltage rise and falls by responding to the outputs of DGs [111]. Considering that the penetration from intermittent DGs is growing by a large scale but some generating units have to be curtailed due to the thermal constraints of power networks, the DSM programmes may reduce the generation curtailment by matching local energy demand with DGs' generation to allow more units to operate, i.e. to improve the export capability of DGs' sites. Broadly speaking, DSM programmes take two forms: reduction of peak demand (also known as peak shaving) and changes to electricity usage pattern. The former is concerned with technologies used for efficient energy conversion process to reduce the overall demand consumption while the latter with shifting of an appropriate amount of the peak demand to other times when demand is much lower. On that basis, potential benefits of DSM applications are summarised in Table 2-10.

Table 2-10 Potential benefits from DSM programs ([23][110])

Deducted peak demand	***Altered usage pattern***
Decreased energy production costs	Enhanced security of supply
Lower carbon emissions from electricity transmission process	More controllability for network operators
Reduction of generation margins	Improved operation efficiency
Less risks with lower voltage limit violations and overloads on transmission lines	Mitigation of intermittent renewable power generation
Deferred network reinforcement and less requirement on system reserve	

There are "passive" and "active" DSM methods depending upon the way a certain method is executed. Examples of passive methods include introducing energy saving appliances or proposing variable electricity tariffs during the course of a day, e.g. two ratings for daytime and night time for Economy Seven users. Active methods usually involve direct control over appliances in certain households such as "smart devices" responding to real-time electricity pricing signals. Major techniques are briefly listed as below [112] [113]:

- Modifying the power curves (or load shape curves)
    - Reduction of night-time heating with load switching
    - Replacement of motors
    - Peak clipping/Trough filling
- Direct-load control
    - Load limiters

    - Commercial/industrial programmes
    - Frequency regulation
- Pricing of demand
    - Time-of-use pricing
    - Demand bidding
- Smart home automation systems
    - Energy saving appliances
    - Smart metering and appliances

Existing DSM programmes have not been extensively deployed in the running of electricity markets. It is anticipated that, if implemented, DSM customers will have more choices for energy consumption and SOs will benefit from these manageable customers due to enhanced security of operation. The implementation of DSM programmes typically involves the identification of objectives, assessment of technical options [114] and appropriate communication systems from customers' sites to control centres [115]. A field trial implementation of a DSM system in Ireland is presented in [116]. In particular, the collision between DSM and smart grid concepts has sparked interest in the use of smart meters and intelligent billing systems to enhance DSM functionalities [117]. The following challenges have been identified with regard to the implementation of DSM programmes in power systems [23] [113]:

- Lack of information and communication technology infrastructure
- Increased complexity to system operation
- Unsuitable electricity market structure
- Lack of incentives and competitiveness

2.5 Network Management and Control

Nowadays distribution systems include a great number of overhead lines, underground cables, substation transformers, reactive compensation equipment, DGs, loads, protection devices and other ancillary equipment [87]. On the other, in the face of the increasing power penetration from non-controllable DGs and growing electricity demand, DNOs must ensure a safe and cost-effective management of the complex networks [52]. Some of the smart grid initiatives brought forward in the UK have also suggested that the management of distribution networks should become more active [34].

2.5.1 Regulations for Network Management

The operation of distribution networks plays a crucial part in maintaining secured and reliable power supplies to electricity users. For any electricity distribution licence holder in the UK, the Electricity Act 1989 that was altered by the Utilities Act 2000 has two clear requirements: guarantee of an efficient, economical and coordinated electricity distribution system and the boost of competition in the electricity supply chain and power generation sector [52]. In the UK, distribution networks are managed to minimise disruptions to electricity consumers by complying with the Distribution Code [19], Engineering Recommendations [20] as shown in Table 2-11 and "The Electricity Safety, Quality and Continuity Regulations" [118]. In particular, standards of statutory voltage limits that DNOs need to comply with are specified in reference [119].

DNOs in the UK are obliged to improve network performance and maintain a good level of quality of service. For instance, Ofgem has specific targets to reward or penalise DNOs on account of the number of customer interruptions (CIs) and customer minute lost (CMLs) [120].[11] In order to effectively monitor and control distribution networks, SCADA systems have been widely used with DMS at substations and feeders to allow DNOs to collect information, analyse data and take responsive actions. DMS programmes adopted in some countries generally have the following basic functionalities [24]: control room graphics system, SCADA, analytical application of load flow analysis and outage management. In the UK, SCADA systems are distributed throughout power systems at 33/11kV level and above. There is a lack of monitoring and control over 11kV/400V substations.

[11] CI = (Number of customers involved in an incident x 100) / Total number of customers in DNO
CML = (Number of customers out-of-supply x Time out-of-supply in minutes) / Total number of customers in DNO

Depending on the availability of remote control facilities, control actions that can be taken via SCADA/DMS primarily include: isolating a part of distribution network by opening circuit breakers to clear a fault, reconfiguring the distribution network for better utilisation of energy resources and restoring supply to consumers after blackout [39]. In addition to SCADA and DMS systems, some local control schemes are in place in distribution networks such as the automatic voltage control (AVC) schemes extensively used on substation transformers in the UK [121], which is further discussed in section 3.5.

Table 2-11 Major Engineering Recommendations in the UK regarding planning distribution networks ([20])

ER	*Specifications*
G5/4-1	Planning levels of harmonic voltage distortion and connection of non-linear equipment to transmission and distribution networks
G59/2-1	Recommendation for the connection of private generating plant to the public distribution systems
G75/1	Recommendation for the connection of distributed generating plant to the public distribution systems above 20kV or with outputs exceeding 5MW
G83/1-1	Recommendation for the connection of small-scale DGs (up to 16A per phase) in parallel with public LV distribution networks
G81	Framework for design and planning, materials specification, installation and record for low voltage house development installations and associated new HV/LV distribution substations
P2/6	The expected level of security of supply for designing distribution networks [12]
P28	Planning limits for voltage fluctuations caused by industrial, commercial and domestic equipment
P29	Planning limits for voltage unbalance for 132kV and below

[12] When the expected level of security of supply cannot be maintained, DNOs take justified actions with respect to the quality of supply incentives regarding CML and CI.

2.5.2 Challenges to Network Management

Traditionally DNOs cope with network issues such as demand growth by upgrading transformers or lines, building new substations and transferring load. These days, challenges for DNOs have emerged with the rapidly changing environment in power industries often due to the limitations of existing practice and newly introduced policies or incentives. For instance, emerging challenges due to growing DG penetrations and increasing electricity demand have led to the necessity of improving distribution network management practices [23].

Some notable challenges are faced by DNOs in the UK distribution systems. Firstly, as discussed in previous sections, automatic monitoring is enabled from HV systems to as low as 11kV networks; decisions with regard to the operation of the distribution systems are centrally made by DNOs whereas available controls for LV networks are generally decentralised and manually executed [52]. Secondly, the UK distribution networks have undergone dominant development during 1960s and 1970s; many of the assets installed since then are reaching the end of their life expectancy [58]. As a consequence, it is of vital importance for DNOs to maximise the usage of the existing assets in a cost-effective manner while asset replacement programmes may be necessary in some cases for enhanced performance. Thirdly, DNOs are motivated to reduce operational costs, improve efficiency and decrease active power losses under the Distribution Price Control Review (DPCR) [122] to maximum their profits. In addition, peaks and troughs of daily demand are inclined to be of larger magnitude than that of historical demand and the scale of overall demand is predicted to increase because of the anticipated electrification of heat and transport [113].

Above all, as aforementioned, the UK government has initiated a number of incentives for developing renewable generation technologies, which naturally has led to a significant growth in power penetration from the intermittent sources. This drastic change ineluctably entails challenges to existing networks such as reversed power flows and elevates the level of complexity for network operation and control. In summary, DNOs in the UK are faced with a number of challenges arising from the following aspects [123]:

- Continuously growing and varying demand
- Reversed power flows due to growing intermittent DG penetration
- Aging network assets
- Network upgrade or reinforcement
- Limitations of existing monitoring systems and control practice

2.5.3 Potential Solutions to Emerging Challenges

Potential solutions to the immerging issues stand in need of accurate demand and generation forecasting techniques, risk assessment, monitoring of key locations in networks, enhanced management and visualisation of real-time data and strategic management of demand [52]. To assist DNOs to cope with rising challenges and enable an actively operated network, a number of innovative technologies have been proposed and developed as new solutions [124]. Correspondingly, the term Active Network Management (ANM) has become popular in the context of power systems, yet there is no standard definition [125]. An example definition is:

> "ANM is the real-time management of power flows, voltages and fault levels to meet acceptable operational criteria using control devices, control systems or control practices on site or via a communication system between the network operator and the control devices [124]."

ANM technologies should aid DNOs to maintain a satisfactory level of quality of power supply under the changing network conditions by coordinating control operations of network equipment using advanced algorithms or devices via monitoring and communication links. The concept of ANM acquires a fundamental shift of the network design and operation practice from the existing 'fit-and-forget' approach to a more strategic management manner [59]. A key concept within the ANM concept is 'Active Control'; it mainly refers to a system capable of monitoring the network, making decisions when required and executing actions accordingly in a real time manner [39]. The following tasks are typically involved in active control: regular measurement of the network condition, rule-based assessment of the comparison of the measurement with analysis results from predetermined model, a set of solutions to actuate network components e.g. generator control or transformer tap changer and eventually a completion indication to the control room.

An example of part of an actively managed distribution network as described above is shown in Figure 2-9, where measurements of power, voltage and currents are taken at 33/11kV substation outgoing feeders and processed by algorithms to determine the appropriate control instructions for substation transformers, loads, embedded DGs and available reactive compensation equipment. An ANM scheme may make use of measurements at the distribution feeders as well as those at DGs' site, allowing the voltages at the end of distribution feeders to be estimated and substation transformers to be regulated to ensure that voltage experienced by consumers do not exceed the requisite limits. For instance, GenAVC is one of the voltage control schemes that are currently commercially available, as introduced in section 3.2.3.1.

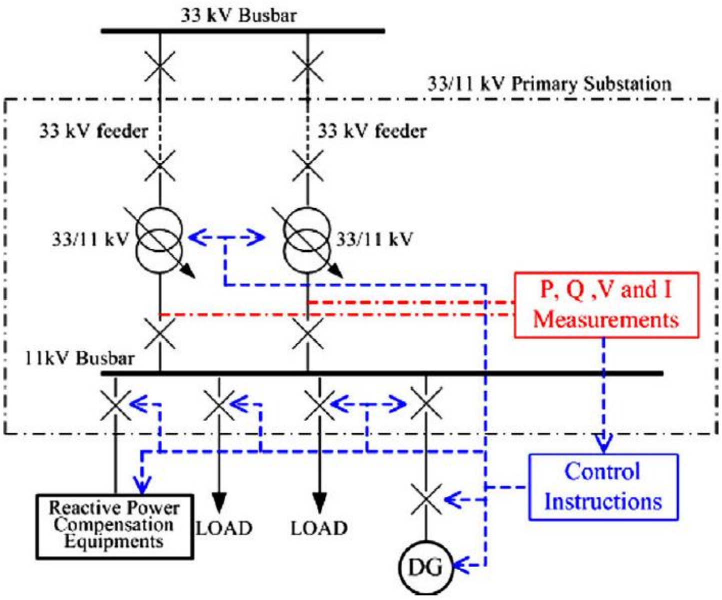


Figure 2-9 Distribution Network with Local Controllers ([126])

Technical solutions of ANM mainly involve the management of network voltage levels, fault levels and power flows. Equipment or systems typically involved in ANM schemes include ULTC transformers, reactive power compensation devices, active voltage controllers and dynamic line rating systems [28]. Adopting ANM techniques incurs different implications to different participants in the power industry [59]. In theory, the implementation of ANM solutions can improve the overall efficiency of network operation for DNOs, enhance the quality of power supply to customers and increase the export capability for DGs. In practice, the deployment of ANM techniques may need DNOs to install monitoring devices at customer sites and DG sites or upgrade network components which could be highly costly. The following major technical issues have to be born in mind for ANM technologies [125]:

- Lack of monitoring and control of 11kV network and below
- Decision making levels and data collection strategy
- The coordination of voltage control equipment
- The coordination of DGs' operation
- Standardisation of communication protocols

2.6 Summary

This chapter has introduced the SCADA system used in distribution networks along with state estimation techniques. The characteristics of distribution networks, DG technologies and load types have been described; the impact of the DGs on the operation of the existing networks has also been discussed. State-of-art control and management practices adopted in the UK for managing distribution networks and the major new technologies designed for accommodating growing renewable generation have been reviewed and discussed. The major differences between distribution and transmission systems have been identified in this chapter.

The major regulations that DNOs need to comply with have been introduced as well as the new challenges posed by growing power penetration from DGs to be tackled by DNOs. Some of the new network management techniques, which have been recently proposed to actively regulate the operating conditions of distribution networks, have also been briefly described in this chapter.

3. Voltages Control Analysis and Practice in Distribution Networks

This chapter deals with the relationship between voltage and reactive power in power systems and introduces practical voltage control equipment and reactive power sources. Emphasis is given to the analysis about the voltage drop along feeders in distribution networks and the challenges that have emerged in distribution systems in relation to voltage regulation. Cost analysis for voltage control methods is also included in this chapter.

3.1 Introduction to Voltage Control

As mentioned in previous chapters, voltage regulation is important not only in transmission systems but also in distribution networks. The fundamental purpose for voltage control policies is to keep electricity users' experienced voltages inside statutory limits [2]. This is because all appliances and electric devices used by consumers are designed to function at its maximum efficiency upon some defined nominal voltages and some deviations from the nominal values should be tolerant considering inevitable supply instability [127]. In addition to required limits on voltages, reactive power flow in power systems should be minimised to diminish active power losses in transmission systems.

3.1.1 Necessity of Voltage Regulation

It has been proved that voltage control is a complicated task on grounds that the relationship between reactive power and voltages is nonlinear and the reactive power requirement in power systems hinges on the loading conditions and is therefore variable and the reactive support provided by various sources has different characteristics [2]. Voltage regulation is of vital importance in power systems operation for various reasons [2]. First of all, voltage is a measure of power quality; stable voltage levels are an indication of secured power supply [127]. Secondly, appropriate voltage regulations can ensure that appliances do not wear out easily. If the voltage at consumers' site is too high, appliances may be subject to safety issues; if too low, they may not work to a satisfactory extent. Thirdly, if not managed correctly, voltage drops in power systems can lead to voltage swings or sags or even blackout in certain areas, often in relation to inadequacy of reactive power support. Thereby voltage regulation should be coordinated with reactive power dispatch (RPD) to maintain reliable power delivery. Three major benefits have long been identified in terms of voltage control and RPD [35]:

1. Efficient use of reactive power resources entails a decrease in active power losses in power systems as well as savings in energy fuels
2. Reactive power management can improve power factors of generation towards unity and system security
3. Reduced voltage gradients between different nodes from improved operation

In UK distribution systems, DNOs are obliged to maintain voltages within the following limits: ±10% at 132kV, ±6% at 33/11kV, +10%, -6% at 400/230V, as shown in Figure 3-1.

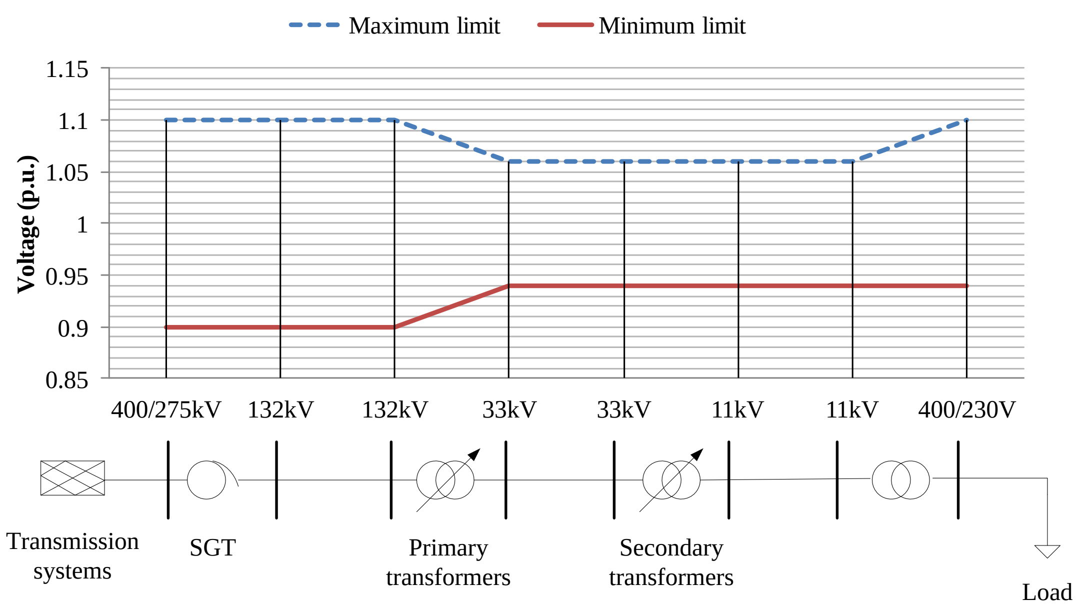


Figure 3-1 Statutory limits at UK distribution networks (adapted from [39])

Voltage fluctuations typically experienced in power systems within a short span of time (minutes) are categorised into two major types: voltage step changes and cyclic or random continuous voltage changes [128]. In the GB SQSS, there are also constraints on the voltage step change, defined as the voltage deviation between the steady state value before a fault or outage and that afterwards, i.e. at the end of the transient time period. The terms commonly encountered in power system quality studies are shown in Table 3-1. The voltage flicker limits are especially defined in the ER P28 document.

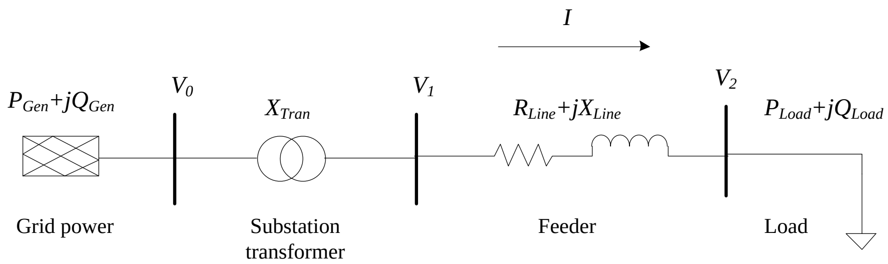
Table 3-1 Definitions of phenomenon related to the measure of voltage quality ([128][129])

Phenomenon	*Interruptions/disturbances*	*Definitions*	*Duration*
Transient overvoltages	System switching disturbances, e.g. capacitor switching	A switching surge or an impulse spike at the voltage waveform	< 0.5 cycle[13]
Voltage flicker	Loads drawing large and variable currents; starting of electric motors	Fluctuations in the system voltage causing visible light flicker	< 0.5 cycle
Voltage dip (sag)	Temporary loss of supply, sudden start of large motors	A sudden decrease of voltage (by 10% to 90%)	0.5 cycle to several seconds
Voltage swell	Temporary loss of load	A sudden increase of voltage (by 10% to 90%)	
Voltage notch	Communication process in AC-DC converters	Periodic transient distortion to the voltage waveform	Within each cycle
Voltage unbalance	Asymmetry of equipment and asymmetry of load states	The magnitude of each phase of the three-phase system is not identical; the phasor difference between each phase is not 120 degree	< 0.5 cycle

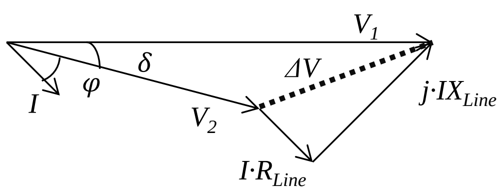
[13] One cycle refers to one complete time period when system voltage and current go through their cyclic waveform, calculated by *T=1/f*. For a system with the frequency being 50Hz, one cycle is 0.02 second.

3.1.2 Voltage Control Analysis in Distribution Networks

Equipment used in distribution substations include transformers, outgoing feeders, voltage regulators, protection devices and in some cases reactive power compensators. Substations in distribution systems provide power to consumers via one or more outgoing feeders. Depending on voltage levels, there are primary and secondary distribution substations. In the UK, primary substations are at voltage levels of 33/11kV and secondary substations step down the voltage from 11kV to low voltage levels [52]. Figure 3-2 depicts the schematic diagram of voltages in a distribution network with a load having a lagging power factor. In figure (a), P_{Gen} and Q_{Gen} represent the active and reactive power output from the grid (or the grid supply point), X_{Tran} represents the reactance of the substation transformer, V_0, V_1 and V_2 represent the voltage phasors at the primary and secondary winding of the transformer and the voltage at the end of the distribution feeder respectively, R_{Line} and X_{Line} represent the resistance and reactance of the distribution feeder that supplies the active demand P_{Load} and reactive demand Q_{Load}. In figure (b), φ is the phasor difference between voltage vector V_2 and current vector I, δ is the phasor difference between voltage V_1 and V_2.



(a) One-line diagram of a distribution network



(b) Phasor diagram

Figure 3-2 One-line diagram and phasor diagram of voltages in a distribution network ([130])

The current I flowing through the radial network branch is

$$I = \frac{S^*_{Load}}{V^*_2} = \frac{P_{Load} - jQ_{Load}}{V^*_2} \tag{3-1}$$

The voltage difference ΔV between V_1 and V_2 along the feeder is

$$\Delta V = V_1 - V_2 = I(R_{Line} + jX_{Line}) \tag{3-2}$$

By rearranging equation (3-2) and substituting the equation (3-1) for current I, the voltage at the start of the feeder V_1 is the sum of the load voltage V_2 and the voltage drop ΔV along the feeder:

$$V_1 = V_2 + \Delta V = V_2 + \frac{P_{Load} - jQ_{Load}}{V_2}(R_{Line} + jX_{Line}) \tag{3-3}$$

Since the voltage angle difference between the two ends of the feeder is small, the imaginary part of the equation shown above can be simplified to:

$$V_1 = V_2 + \frac{R_{Line}P_{Load} + X_{Line}Q_{Load}}{V_2} \tag{3-4}$$

3.1.3 Voltage and Reactive Power

Reactive power, a component of instantaneous power in AC systems, is the power circulated in power grid to support its operation via the exchange of magnetic and electric fields [127]. Reactive power is generated by storing energy in electric fields and consumed by producing magnetic fields. In AC power systems, reactive power exists when there is a phasor difference φ between voltage and current and is measured in volt ampere reactive (VAR). It is generated when the current vector is leading the voltage vector, i.e. a leading power factor, and absorbed when current vector is lagging the voltage vector, i.e. a lagging power factor. The adequacy of reactive power support is typically indicated by the power factor (*p.f.*), defined as the ratio of active power to apparent power, shown in equation (3-6).

$$p.f. = \frac{P}{S} = \cos\emptyset \tag{3-5}$$

Due to the dominance of the reactance in the impedance of many network components, it has been observed that the difference in voltage angles at different locations entails the flow of active power whilst the difference in voltage magnitudes enables the flow of reactive power: reactive power flows from busbars with higher voltage magnitude to those with lower voltage magnitude. Hence, by controlling the reactive power injection and absorption, voltage levels can be regulated. Reactive power generation and absorption in power systems are balanced at a certain level of voltage. The nonlinear nature of the relationship between voltage and reactive power makes voltage control by dispatching reactive power a nonlinear problem.

Since it is required that voltage magnitudes should not differ greatly from the nominal value, reactive power can only propagate for relatively shorter distances than active power, making reactive power compensation necessary where distinctive voltage drops or rises tend to occur [2]. In an intact transmission system, all electrical equipment should be operated within a specified voltage range, but in practice, voltage drops along transmission lines may decrease or increase during heavy or light load conditions. Therefore, it is necessary to compensate reactive power at certain nodes to maintain acceptable voltages and also to increase line loadability by reducing reactive power flows. Reactive power resources are generally distributed throughout power systems to provide local voltage support for both transmission and distribution systems.

Reactive power support is essential for power system reliability by maintaining satisfactory local voltage levels and voltage step changes from steady state to post fault operating state [127]. VAr compensation is also referred to as power factor correction and can be provided in shunt or series, as illustrated in Figure 3-3. Examples of reactive power sources are introduced in section 3.3, where the notations for symbols are the same as in Figure 3-2 and Q_{Comp} refers to the reactive power compensation. It can be seen that reactive power can be provided to distribution systems in series with distribution feeders or in shunt with the feeders at either the high or the low end. In particular, series reactive power compensation improves the loadability of the line to which it is connected by reducing the total capacitive component of the line impedance.

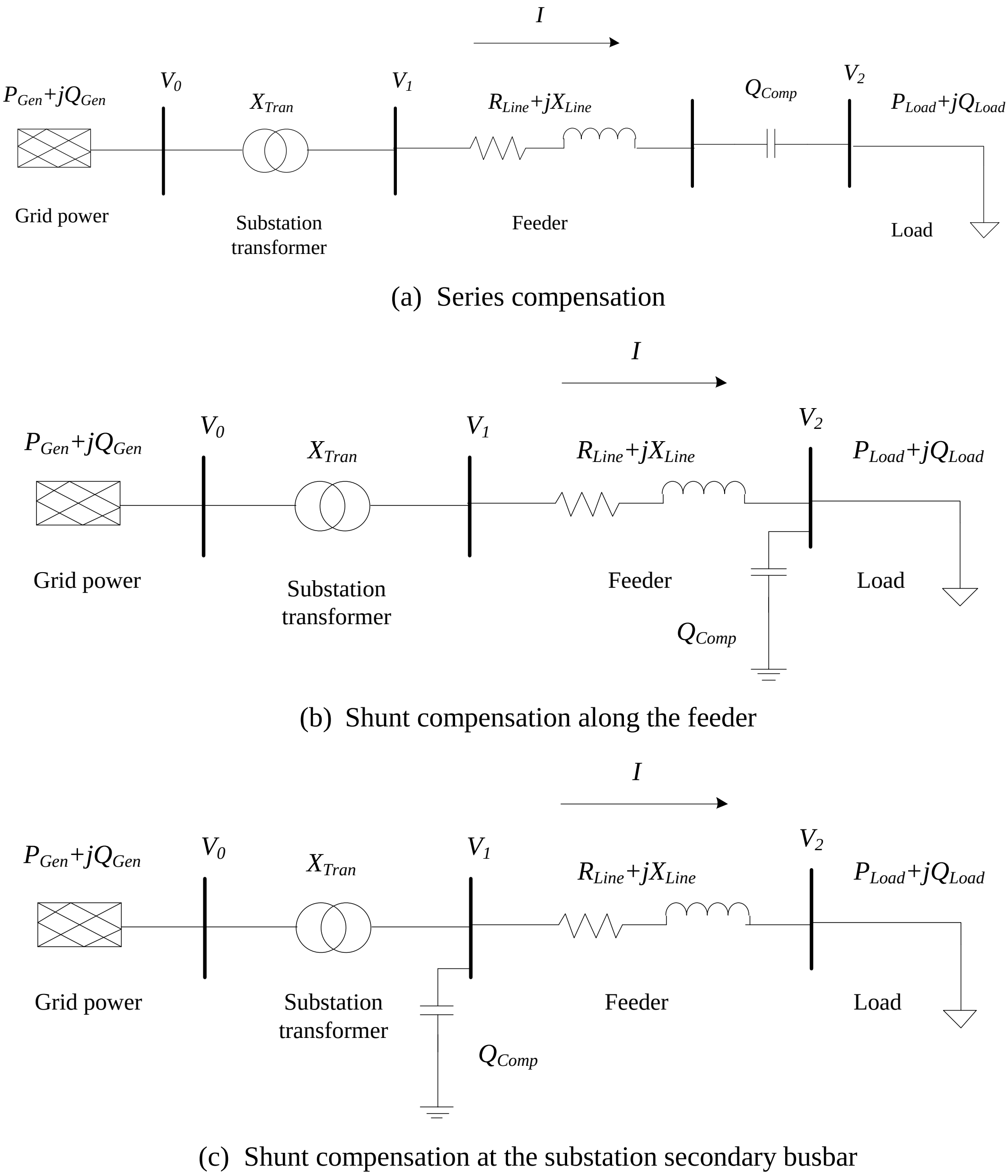


Figure 3-3 Types of reactive power compensation in distribution networks ([131])

3.2 Direct Voltage Control Methods

Voltages in power systems are generally controlled either directly by synchronous generators' AVRs and tap-changing transformers or indirectly by reactive power compensation devices but voltage performance is also subject to network characteristics as well as planned or unplanned events [2]. In practice, monitoring devices are installed at important locations in power systems and voltage measurements along with power flow measurements are delivered to SOs via communication links so that off-line studies can be performed to improve voltage profiles for an intact system as well as contingencies.

3.2.1 Generator Voltage Control and Reactive Power Capability

Synchronous machines are operated at provisional voltage levels with a rating expressed in the maximum MVA. The generator terminal voltage can be directly regulated using an automatic voltage regulator (AVR) that responses to the difference between output voltage and a pre-set reference voltage by changing the field current using the generator exciter via a feedback closed loop and, as a consequence, the reactive power generated or consumed is varied [2]. Specifically, synchronous generators supply reactive power when overexcited and consume reactive power when under-excited. Due to its thermal heating effects, the field current is limited to a certain level thereby restraining the reactive power capability. This capability is also constrained by armature current and end region heating limits, as depicted in Figure 3-4, where P_{max} is the maximum active power output of the generator and Q_{max} and Q_{min} refer to the maximum and minimum limits of reactive power output and the contour outlined by the three types of limits shows the generator's production capability. Usually a specific power factor is respected (e.g. 0.85 or 0.9 lagging) so that the VAr limits can be respected when voltage control is executed. When there is a deficiency of reactive power support in power systems, synchronous generators may reach these limits in which case the terminal voltage will be different from the set reference value. It is normally preferred by generators to export such an amount of reactive power that there is a sufficient reactive margin available to regulate voltage when unanticipated events occur.

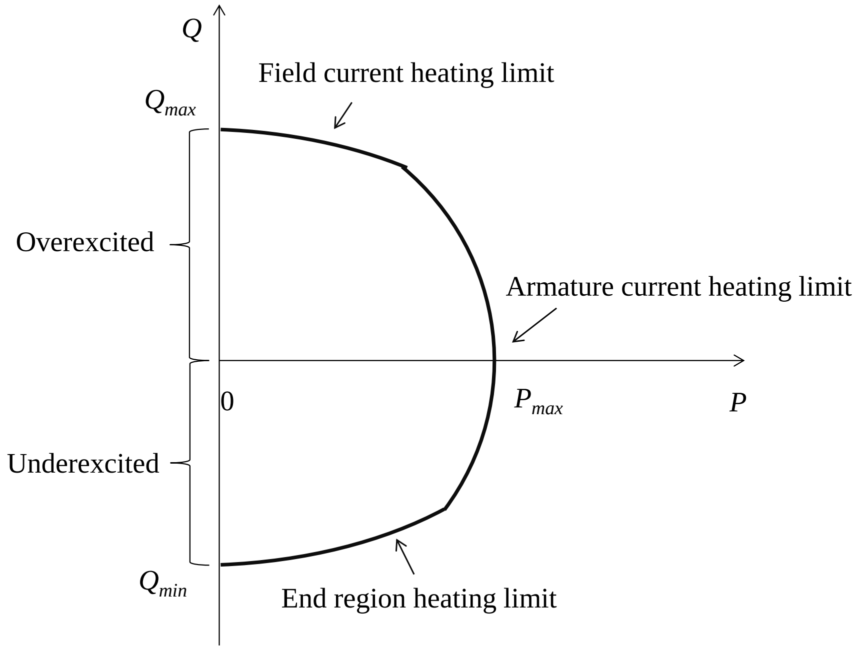


Figure 3-4 Reactive capability of synchronous generators (adapted from [2])

As for asynchronous (or induction) generators, reactive power capability is typically provided by external equipment such as capacitors and static VAr compensators (SVCs) [132]. In the UK, NGET requires generators that are participating in energy trading to have reactive power capabilities to improve voltage levels when necessary; the specific obligations are stated in Grid Code CC 6.3.2 [18]. In general, reactive power suppliers should be able to operate between 0.85 power factor lagging and 0.95 power factor leading [133].

DG voltage control and reactive power capabilities

DGs that are connected to grid via synchronous generators, doubly fed induction generators (DFIGs) or power electronics interface are capable of adjusting reactive power output and hence can contribute to the voltage regulation in the MV and LV networks when required by operators [134]. In particular, the control of reactive power for power electronics interfaced DGs is independent from the control of active power. The inverters of PV systems and synchronous generators of CHP systems also have the capability to supply dynamic reactive power to cope with voltage variations. Although PV systems generally have a much smaller size than large generators, power electronic inverters for these systems can provide a small amount of reactive power locally.

With regard to wind turbines, their reactive interactions with connected networks depend on electronics interface, the type of generators and the status of connection [135]. Wind turbines that are connected to grid via fixed-speed induction generators (FSIG) normally consume reactive power to maintain the magnetic field and therefore do not possess the capability to adjust reactive power output. Therefore, capacitors are usually installed to improve the power factor at the point of connection.

Unlike FSIG wind turbines, variable-speed wind turbines can adjust reactive power output. The two most popular examples of variable-speed wind turbines are DFIGs wind turbines and fully rated converter (FRC) wind turbines based on synchronous or induction generators. Power converters are typically used with DFIGs to decouple the frequency of the electrical grid from the rotor frequency, which enables the speed of turbine operation to be variable. DFIG wind turbines control the active and reactive power output independently: active power output is variable depending upon the wind speed while reactive power output depends on the rotational speed of the generator; reactive power is drawn by the generator rotor from the grid when the generator operates below synchronous speed and vice versa [135][136].

Similar to DFIG wind turbines, FRC wind turbines employ power converters to allow variable-speed operation by separating the dynamic operation of the generator from the grid [135]. The power converters in FRC wind turbines can provide or absorb reactive power and the control of active power and reactive power is independent from each other. However such individual controls of wind turbines may not be able to regulate the voltage at the point of connection in that wind farm networks are mainly capacitive due to cable connections [135]. Reactive compensation devices may be required to improve the voltage at the point of connection; such devices include shunt-connected capacitors, static synchronous compensators (STATCOMs) and static VAR compensators (SVCs).

Nonetheless, the availability of reactive capability for a variable speed wind turbine is around 60-80% of the time considering that some wind turbines have to be disconnected from the grid at times at times when the wind speed cannot reach the specified cut-in speed, i.e. the minimum value of wind speed that can enable a wind turbine to generate power, or when the wind speed exceeds the specified cut-out speed, i.e. the maximum wind speed that a wind turbine can operate at to avoid safety hazards on the blades and motors caused by too high wind speed [134] [137].

3.2.2 Tap-changing Transformers Voltage Control

3.2.2.1 Modelling

Tap-changing transformers are one of the most commonly used voltage control equipment throughout electrical power systems. It not only allows power to be transmitted with low voltage drops and high efficiency but also enables voltage control by a tap changer that is fitted at the primary or secondary side of the transformer [2]. The equivalent circuit for a practical single-phase two-winding transformer is illustrated in Figure 3-5 [1]. The circuit consists of an ideal transformer, the shunt magnetising impedance and the leakage impedances at primary and secondary windings.

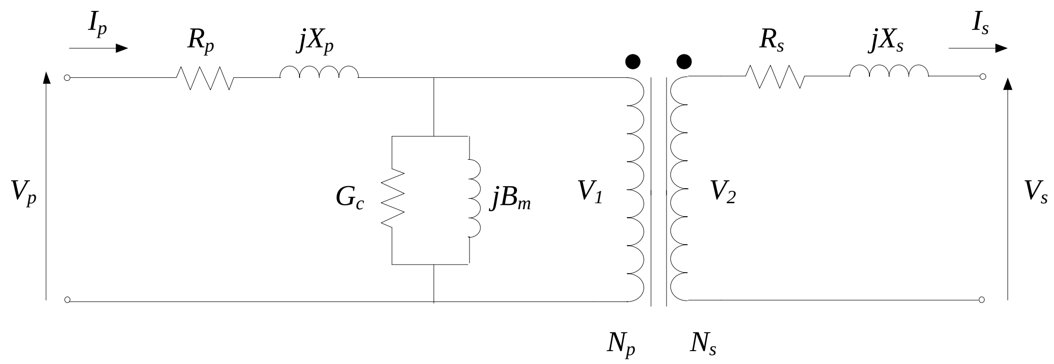


Figure 3-5 Equivalent circuit of a single-phase two-winding transformer ([1])

Notations V_p, I_p and V_s, I_s represent voltage and current at primary and secondary side of the transformer respectively; R_p, X_p and R_s, X_s represent the resistance and reactance of the primary and secondary windings; G_c, B_m represent the core conductance and magnetising susceptance.

In load flow analysis, some idealised assumptions are made to simplify the modelled representation of transformers, e.g. both windings have negligible resistance and active power losses; core losses can be ignored and there is no leakage flux [1]. For ideal transformers, the voltage ratio is equal to the transformer turn's ratio as shown in equation (3-6). Since the power at the primary side is equal to that at the secondary side, shown in equation (3-7), the current ratio is the inverse of the tap ratio, as shown in equation (3-8). The model of an idealised transformer is used in all the relevant case studies carried out in this thesis.

$$\frac{V_p}{V_s} = \frac{N_p}{N_s} = n_{ps} \tag{3-6}$$

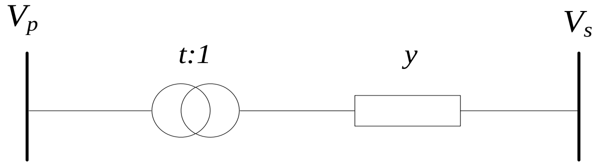
$$S_s = S_p \tag{3-7}$$

$$\frac{I_p}{I_s} = \frac{N_s}{N_p} = \frac{1}{n_{ps}} \tag{3-8}$$

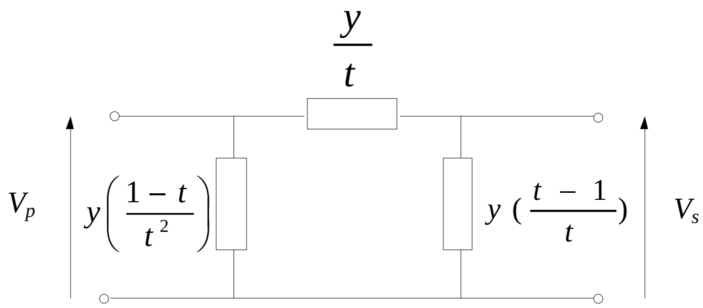
where V_p, I_p and V_s, I_s are the voltage and current at the primary and secondary side of the transformer, N_p and N_s are the number of turns at the two sides, n_{ps} is the tap ratio between primary and secondary turns, S_s and S_p refer to the apparent power at the primary and secondary windings. It should be noted that regarding the distribution transformers, the tap ratio is referred to as the ratio of the secondary voltage and the primary voltage.

The tap ratio indicates how the primary voltage is transformed to secondary voltage: a scalar value indicates that only voltage magnitude is transformed while a complex value means a transformation of both the magnitude and angle used by phase-shifting transformers [1]. A tap ratio is said to be nominal when the primary and secondary voltages are at their nominal or base values; the nominal value of a tap ratio is equal to one when voltages are expressed in per unit. An off-nominal tap setting refers to the setting when voltage at any winding is not equal to the ratings [138]. According to equation (3-6), if a tap changer is installed on the primary side of a transformer, then the higher percentage the tap position (or the higher the tap ratio), the lower the secondary voltage considering that the supply voltage at the primary side remains almost constant.

The primary reason for having tap-changers for the application of transformers is to regulate the secondary voltage when the system load level changes [139]. A tap-changing transformer is normally represented by a short circuit admittance connected in series with an ideal transformer; the one-line diagram of a two-winding tap-changing transformer with an admittance of y and a tap ratio of $t{:}1$ and its equivalent circuit are illustrated in Figure 3-6.



(a) One line diagram of a two winding transformer



(b) Equivalent π model of a two winding transformer

Figure 3-6 General representations of a two winding transformer (adapted from [138])

The admittance matrix for the above model of a two winding transformer is calculated as shown below [138]:

$$\begin{bmatrix} I_p \\ I_s \end{bmatrix} = \begin{bmatrix} \frac{y}{t} + \frac{y(1+t)}{t^2} & -\frac{y}{t} \\ -\frac{y}{t} & \frac{y}{t} + \frac{y(t-1)}{t} \end{bmatrix} \begin{bmatrix} V_p \\ V_s \end{bmatrix} = \begin{bmatrix} \frac{y}{t^2} & -\frac{y}{t} \\ -\frac{y}{t} & y \end{bmatrix} \begin{bmatrix} V_p \\ V_s \end{bmatrix} \tag{3-9}$$

The self-admittance and mutual admittance between the primary and secondary nodes where a transformer with an admittance of Y is connected are:

$$Y_{ps} = Y_{sp} = Y/t$$
$$Y_{pp} = Y'_{ss} + Y \quad (3\text{-}10)$$
$$Y_{ss} = Y'_{pp} + Y/t^2$$

where Y'_{pp} and Y'_{ss} are the self-admittance of the primary and secondary busbars without considering the admittance of the transformer [140].

Transformers always absorb reactive power by producing magnetic fields in spite of loading condition. The shunt magnetising reactance effect prevails at no load and the series leakage inductance prevails at full load. The reactive power absorbed by a transformer can be calculated using equation (3-11).

$$Q_{Tran} = \frac{S_{load}^2 X_{p.u.}}{S_{rated}} \quad (3\text{-}11)$$

where $X_{p.u.}$ is the per unit reactance of the transformer, S_{rated} is the rated VA of the transformer and S_{load} is the VA of the load. It can be observed from the equation that the heavier the loading, the more reactive power absorption.

3.2.2.2 Tap-changing mechanism

There are two major types of transformers used by power utilities: under-load (or on-load) tap-changing transformers at high costs that can adjust tap positions with the load connected and off-load tap-changing transformers with low costs whose tap changers need to be manually adjusted with the load disconnected and hence would affect the reliability of power supplies [141]. Generator transformers are typically equipped with off-load tap changers with a small voltage variation e.g. ±5%, to step up voltages levels for power transmission [142]. As a matter of fact, the change in off-load tap changers usually would occur only once or twice throughout the lifetime of a transformer [143].

Tap-changing devices include taps or leads that can be connected either to the primary or secondary coils at different locations to maintain a stable voltage at the secondary side of the transformer under varying loading conditions. A diagram illustrating the basic arrangements of tap changer windings is shown in Figure 3-7. Typically, the linear arrangement in (a) means a proportional relationship between the voltages at the primary and secondary winding and is applied to power transformers with a tapping range up to 20% [144]. The arrangements shown in (b), (c), (d) and (e) are the most commonly used change-over selectors for tap changer windings. In most load flow calculations, the linear arrangement is typically considered for simplicity.

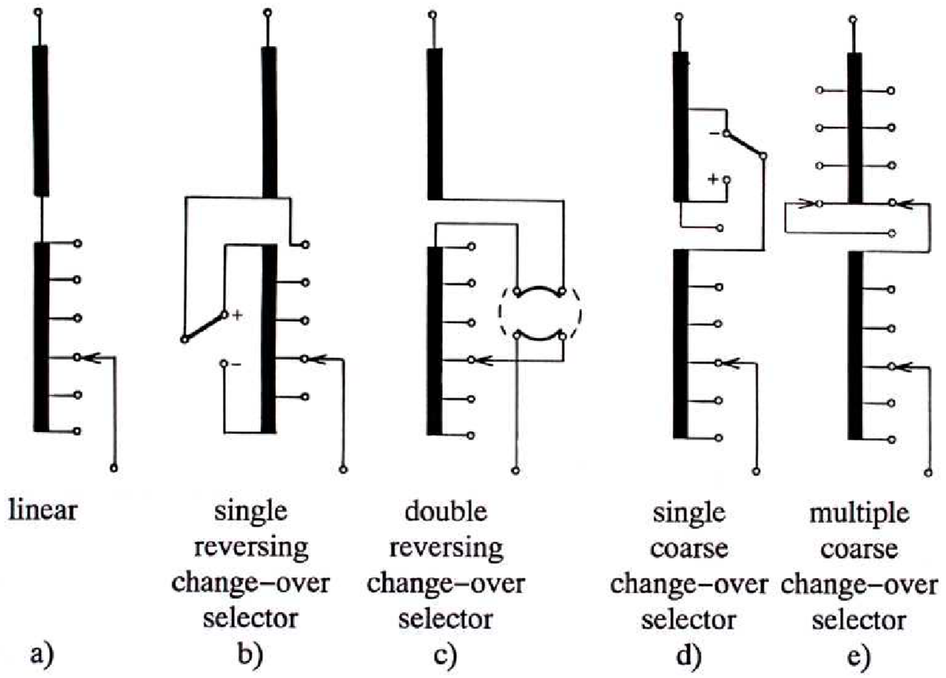


Figure 3-7 Basic arrangement of tap changer windings ([144])

Depending on the nature of the impedance, tap changers are normally either resistor-type or reactor-type. The reactor-type tap changers operate slowly and have a relatively shorter life expectancy than the resistor-type, which is why the resistor-type tap changers are most commonly found these days in Europe [139][145]. Tap changers can also be categorised in terms of the mechanism of operation: mechanical or electronic tap changers. Mechanical tap changers have been conventionally used in most power systems and the tap-changing operation is a slow step-by-step (or incremental) process. Electronic tap changers can move between any positions within the control range relatively faster and the tap-changing operation is relatively less discontinuous than mechanical tap changers [139]. However, electronic tap changers are also much more costly mainly due to the number of solid-state switches that are involved in the tap-changing process. Data memory is also necessary for storing tap changer indicators such as the positions of taps and status of switches. As a result of these limitations, electronic tap changers have not been widely adopted.

Tap-changing transformers are characterised by the total number of tap positions (n_{step}), the tap ratio per increment step change (ΔT) and tap position range (maximum and minimum ratios T_{max} and T_{min}), e.g. a range of ±10% in 17 positions with an incremental step of 1.25%. Their relationship is reflected in the following equation:

$$\Delta T = \frac{T_{max} - T_{min}}{n_{step}} \tag{3-12}$$

The ratio of primary and secondary voltages is determined by the existing tap position T according to equation (3-13).

$$T = T_o + n\,\Delta T \tag{3-13}$$

where To is the nominal ratio of primary and secondary voltages, n is the number of tap positions from the nominal position.

The relation between changes in the tap ratio and the primary voltage can be derived based on equation (3-6):

$$\Delta T = T' - T = \frac{V_p' - V_p}{V_s} = \frac{\Delta V_p}{V_s} \tag{3-14}$$

With the assumption of V_s = 1.0 p.u. it can be observed that $\Delta T = \Delta V_p$. Therefore, transformer tap ratios are often equivalent to transformer voltage ratios.

With automatic voltage regulators (AVR), ULTC transformers are capable of adjusting tap positions to deal with the voltage fluctuations on the secondary winding [139]. The basic AVR system includes the following components: a ULTC transformer with a tap-changing mechanism, a motor drive unit, measuring current transformer (CT) and potential transformer (PT), protection devices, a voltage regulator (with a time delay element t_d and a dead band (DB) element) and auxiliary devices. The key settings of such a control system are the target voltage that the regulator aims to reach and the DB setting specifying the appropriate tolerance at either side of the reference voltage. The block diagram illustrating the control system is shown in Figure 3-8.

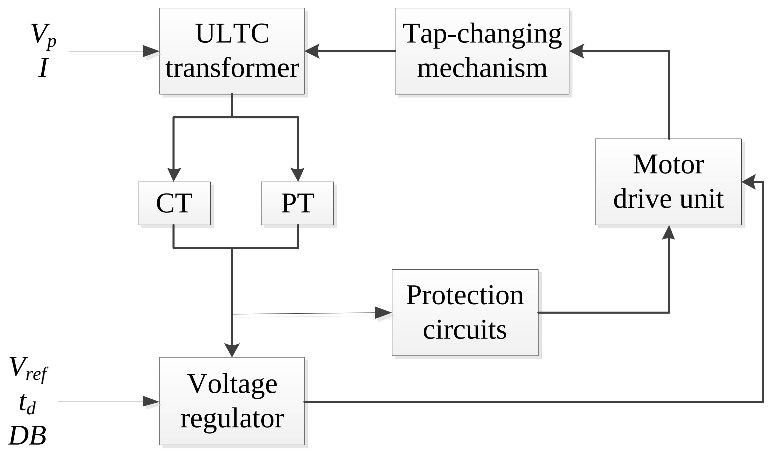


Figure 3-8 Block diagram of a tap-changing mechanism for an ULTC transformer (adapted from [139])

The automatic voltage regulator employs a time delay to account for the time it takes for the control signal to be executed by the motor drive unit on a tap changer [139]. The time delay also helps to avoid unnecessary tap movements during transient times. DB refers to a specific voltage deviation setting (or a voltage bandwidth) against which the measured voltage is compared and the tap changing operation will not be actuated unless the voltage deviation is greater than this setting. The presence of a DB setting is to avoid frequent tap changer operations and thus to reduce the wear-and-tear overtime. Therefore, the value of the DB depends primarily on the voltage step change caused by an incremental tap step change ΔT. If too small the tap changing operation will be too frequent; if too large the tap changer mechanism will not operate adequately to respond to voltage changes. Typically, the value of DB is set to be 2 to 3 times of the incremental tap voltage change, i.e. with the voltage step being 1%, the DB will be set to be within 2-3% [145]. In IPSA+, the power flow software used for case studies throughout this thesis, the value of DB is by default set to be equal to the tap increment and no values lower than this is allowed for load flow calculations. [14]

ULTC transformers that are equipped with AVRs are typically operated either with a fixed tap position setting or under a specified voltage reference (or set point) [140].

[14] IPSA refer to Interactive Power System Analysis.

When the tap positions are specified, the transformer turns ratio is fixed and the ratio between the primary and the secondary voltages will remain unchanged. When the voltage reference is specified for a transformer, tap positions are automatically determined under the AVR scheme. In the Gauss Seidel (G-S) load flow calculations, the new tap positions are computed iteratively using equation (3-15) [146].

$$T_{new} = T_{old} + C\,(V_{set} - V_{act}) \tag{3-15}$$

where T_{new} is the new ratio of transformer voltages, T_{old} is the 'old' voltage ratio (used in the previous calculation), C is the acceleration factor, V_{set} is the voltage set point, V_{act} is the actual calculated voltage. The convergence rate of the load flow calculations is highly sensitive to the selection of empirical acceleration factors for tap-changing transformers. An appropriate value of the acceleration factor will avert excessive tap movements and oscillations in the iteration process [146]. The acceleration factors are typically set to 1.0 to introduce the normal tap change and a value smaller than 1.0 are used to allow for frequent tap movements [147]. Another equation used to express the relationship between the voltage deviations and tap changer position movement is shown as below [148]:

$$\Delta V = S\,\Delta T \tag{3-16}$$

where ΔV is the voltage deviation due to an incremental tap step change, ΔT is the incremental tap change and S is the tap voltage control sensitivity which is normally set to +1 or -1 to provide appropriate results. Equation (3-16), at its essential, is equivalent to equation (3-15).

In the Newton-Raphson (N-R) and fast decoupled load flow (FDLF) calculations, there are two major approaches used for automatically adjusting tap positions. One regards the controlled voltage as the state variable throughout the calculations [140][148], where a tap changer will move up or down to ensure that the voltage at the controlled busbar is within the specified limit, i.e. the value of dead band (DB); this type of methods corresponds to the operation of transformers under a specific voltage set-point. The other method models the tap changer as an independent variable initially and set it to be fixed if any of the tapping limits is reached and use the controlled voltage as the independent variable for the transformer [149][150]; this way of dealing with transformers is a reflection of the fixed tap position setting mode. In each load flow iteration $i+1$, transformer tap positions are updated on the basis of the former iteration i using equation (3-17) [151]:

$$T(i+1) = T(i) + \frac{\Delta T}{T} T(i) \tag{3-17}$$

ULTC transformers are widely used in transmission and distribution systems where frequent operation tends to be required for dealing with variations in daily load. Just like any other network assets, desired performance from transformers should be characterised by a low failure rate, reduced operating costs and extended maintenance intervals and less maintenance efforts. Frequent transformer tap-changing operations will add to the wear-and-tear on the equipment over time and shorten the maintenance interval, which implies more financial costs and greater risks in the loss of supply. In the long term, the life expectancy of the equipment will be reduced and asset replacement may be necessary.

There are two principles for switching of under-load tap changers, the high-speed resistor type and the reactor type under-load tap changer. Resistor type tap changers are normally installed within the transformer tank while reactor type tap changers are fitted into an individual compartment welded to the transformer tank. Tap-changing transformers are normally maintained on the basis of a specific number of operations or maintenance intervals, whichever is reached first. These criteria are set according to tap-changer types and their applications. In particular, the maintenance intervals are dependent upon the maximum allowable number of operations and the wear and tear of the mechanical components such as the energy accumulator springs [141]. Other types of transformers are under development, such as superconducting power transformers; they should bring about less losses and lower footprint but are highly expensive to invest and still need tap-changing devices [152].

3.2.2.3 Control practice

Under-load tap-changing transformers are the most extensively applied equipment by DNOs to improve terminal voltages along radial feeders, particularly the long distance ones where voltage drop could be rather large [152]. The most commonly used ULTC transformers in the UK distribution systems have the characteristics as listed in Table 3-2 and tap changers are typically fitted at transformers' primary windings.

Table 3-2 Characteristics of transformers typically used in the UK distribution networks ([52])

Voltage transformation ratio	*Rating (MVA)*	*Nominal impedance (%)*
132/33kV	45/60/90	13.5/18/27
33/11kV	4/7.5/10	6.7/10.0/10.0

To enable efficient load sharing and to avoid the complete loss of supply, two transformers are usually connected in parallel at distribution substations instead of one transformer. These substation transformers are generally ground mounted or pole mounted with typical tapping limits of ±10% or ±15% with an incremental step of 0.625% or 0.5% [152].

Voltage control strategies in distribution networks in the UK are concerned with automatic voltage control (AVC) schemes at 132/33kV and 33/11kV substations.[15] The automatic control schemes aim at keeping secondary voltages at 33kV and 11kV respectively close to their nominal values [39]. The objective of AVC schemes is to ensure voltage profiles experienced by customers at the end of distribution feeders are within a satisfactory range. AVC schemes typically keep the secondary voltage within the range of ±1% for 11kV or ±1.75% for 33kV [52]. While the transformers at 33/11kV and above voltage levels have adjustable taps, most transformers at voltage levels of 11kV and below have fixed tap ratios. Hence, the voltage level of 11kV is the lowest voltage level that DNOs in the UK are currently able to regulate.

Most AVCs that regulate tap-changers are managed standalone via control loops that adopt static set points and remain unchanged unless required by control centres. The AVC arrangement for ULTC transformers in UK distribution substations is illustrated in Figure 3-9.

[15] In the UK, the term AVC refers to the voltage control mechanism on transformers.

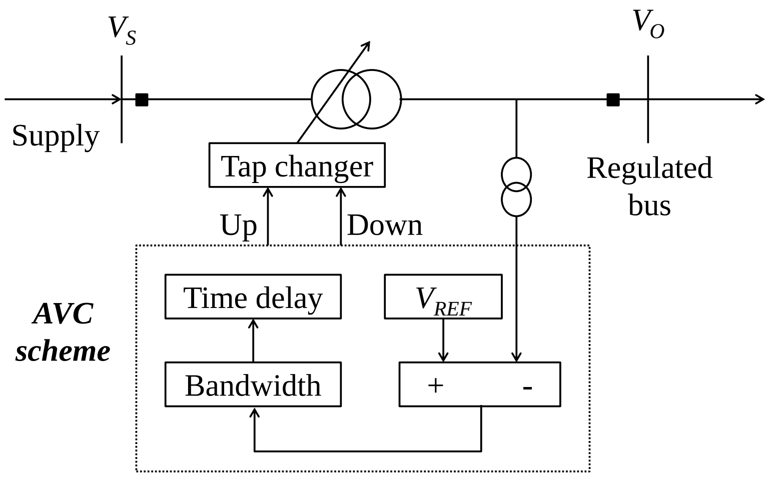


Figure 3-9 Schematic diagram of the AVC scheme applied to ULTC transformers (adapted from [130])

Many DNOs are able to set the set points of the AVC schemes for transformers in primary substations from control centres via SCADA systems. As mentioned in the former section, key settings needed in this control mechanism include the reference voltage V_{REF}, i.e. the target voltage for the regulated bus, the bandwidth setting V_b that defines the tolerant levels from the reference voltage and the time-delay setting that regulates the timing of tap change to prevent false operation caused by transient voltage fluctuations. In practice, considering that tap changers typically incur a 1.5% voltage step change, the bandwidth setting therefore must be greater than ±0.75% to avoid excessive tap changing operations; a setting of ±2% will make sure that the regulated voltage does not fall below -2% or reach above +2% of its nominal value [121]. With an increased number of DGs connected at 11kV throughout the distribution network, most UK DNOs prefer not to allow DGs to directly control voltage, so as to avoid possible conflicts between the transformer AVC schemes and the DGs' AVR controls [121]. If DGs' voltage control were to be in effect, the common practice would be to set the 33/11kV transformers under fixed tap ratio.

3.2.2.4 Associated techniques

Several schemes can be applied within the AVC schemes so that the paralleled transformers share the same tap positions to efficiently share the loading through the equipment and also to diminish the circulation current. The following techniques are commonly involved: line drop compensation (LDC), master/slave arrangement, circulating current compensation (CCC) and reverse reactance compounding (RRC) [121].

LDC

LDC is a technique that compensates estimated voltage drops along distribution feeders on the basis of local measurements at substations; a voltage control relay can adjust the voltage set points of tap-changing transformer busbar to which several distribution feeders are connected [121]. The LDC scheme controls the busbar voltage responding to the load current. The schematic arrangement of an LDC scheme is shown in Figure 3-10.

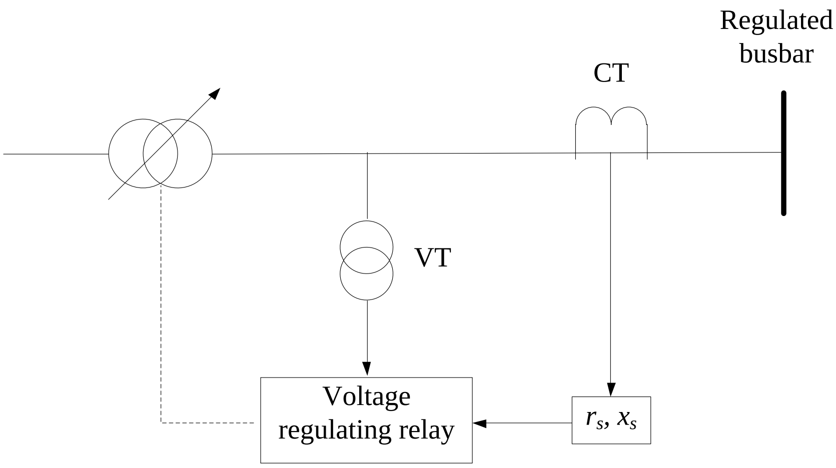


Figure 3-10 Schematic diagram of the LDC scheme ([51])

The voltage compensation scheme applies a current that is in proportion to the transformer load current measured by a current transformer (CT) by considering impedance r_s and x_s that are adjusted to represent the network impedance [51]. The voltage regulating relay is operated by combining the voltage drop and a voltage which is in proportion to the voltage measured by the voltage transformer (VT). The regulating relay then actuates the transformer tap changers or sets an appropriate voltage target to ensure that the voltage at the regulated busbar is within the requisite limits [51].

The LDC technique requires current measurements at the secondary side of transformers; it is normally applied according to the ratio of actual load to full load as an evaluation of the voltage drop at the end of the feeders. Hence the application of LDC is based on accurate measurement of load current [153]. Considering that each feeder is generally unevenly loaded, the estimation of voltages along various points of the feeders is complicated and yet accurate estimation is necessary for LDC to function. Usually maximum demand scenarios are considered for LDC settings to ensure a sufficient boost in voltage levels. In the presence of DG penetration, the LDC can also decrease voltage set points at times when power flows are reversed but it is difficult to obtain accurate estimation of voltages because substation measurements are subject to intermittent DG output and stochastic demand [154]. LDC schemes need to rely on other methods to synchronise transformers' tap steps because the schemes are not stable due to circulating reactive power amongst parallel transformers. A master/slave arrangement or a CCC scheme is usually applied with LDC.

Master/slave arrangements

In a master/slave (or master/follower) arrangement, the tap-changing transformer that absorbs the least reactive power is chosen as the master transformer and its tap position is the master position. The master transformer controls voltages and slave transformers follow its settings to keep tap-changers of parallel transformers synchronised. This principle is particularly appropriate for transformers that have the same step voltages per tap change and MVA ratings provided that the transformers are physically close. The tap changers are initially put into step manually and then the scheme takes lead [121]. The arrangement takes into account different tap position limits of different transformers. If the master tap changer reaches its upper or lower limit, it becomes a slave set to its limit and one of the remaining active tap changers is chosen as a new master. If all of the paralleled transformers are set to their respective tap limits, then the total active and reactive power outputs from the paralleled transformers cannot be regulated, i.e. the associated bus becomes a PQ bus [151].

Circulating Current Compensation

CCC, also referred to as True Circulating Current method, is a scheme for synchronising parallel transformers at the same site or at different sites within a short distance [121]. Under this scheme, the amount of circulating current is monitored and reduced by tap changer control relays [155]. This scheme relies on the wiring amongst transformers to measure the currents flowing through all the parallel transformers. The limitation of this technique lies in the complexity in installation and operation of the scheme.

Reverse Reactive Compounding

Due to the circulating reactive power amongst parallel transformers, voltage control relay sees different voltages and their settings may lead tap changers to reach their limits [121]. RRC effectively applies a negative value for the reactance setting (thus also known as negative reactance compounding) to synchronise tap positions for a number of ULTC transformers and thereby minimise the circulating reactive power amongst these transformers. The RRC scheme is easy to operate without the requirement of manual switching operations and is applied to ensure that tap positions for transformers in an interconnected network do not differ significantly. However, the RRC technique is highly sensitive to power factors; assumed relay settings may not work for systems with insufficient reactive power support, e.g. poor power factors of asynchronous generators. An enhanced RRC scheme is the transformer automatic paralleling package (TAPP) algorithm that adjusts the voltage set points by an appropriate deviation to minimise circulating current. This is achieved by calculating circulating current on the basis of the comparison of the measured transformer power factor with the normal load power factor [153]. RRC voltage control aims at reducing reactive power flows circulating through ULTC transformers and maintaining the same tap position for all the transformers connected in parallel. RRC is particularly useful when transformers are located far from each other because the master/follower or CCC schemes are not practical to deploy [121].

3.2.2.5 Technical risks

The operation of tap changers is regarded as one of the contributing factors for the failures of the ULTC transformers; it can be either a mechanical failure or an electrical break down [156][142]. Consequently, the reliability of tap changers is essential for the daily operation of ULTC transformers and regular inspection on the operation of tap changers is often required. Mechanical faults are typically related to the tap changer driving mechanism while the electrical faults are often due to the contact wear-and-tear. Hence it is important to minimise the number of tap changer operations to reduce the wear and to decrease the risks of the failure of the drive system.

Depending upon the applied medium, tap-changers are generally categorised into two types: oil type and vacuum type. Mineral oil is normally used by conventional power transformers as the cooling and insulation medium to diminish the heating effect from the flow of current inside transformers and to prevent arcing. In the UK distribution networks, most of the substation transformers currently under operation are oil-filled transformers. It has been discovered that moving parts of tap changers could potentially incur safety risks related to sealed oil tanks. For example, tap changing operations involve electric arc discharges which increase the contact wear as well as the risks of oil pollution due to the arcing residues. Pressure relief devices, oil level gauges, oil sampling and temperature alarms are the options to reduce oil tank associated safety risks [28]. Tap changers of the vacuum type are designed to minimise the safety risks associated with oil immersed transformers but are highly costly. Transformers with vacuum type of tap changers [157] might be used by DNOs in future to replace the existing transformers at the end of their life expectancy.

3.2.3 New Voltage Control Schemes

GenAVC and SuperTAPP n+ voltage control relay (VCR) are the two major commercially available voltage control devices developed especially for dealing with voltage control issues at DG integrated distribution networks in the UK.

3.2.3.1 GenAVC

GenAVC is one of the commercialised schemes that have been adopted by a few utilities in the UK for active management of voltage in distribution networks. An illustration of the GenAVC scheme is shown in Figure 3-11. Measurements of voltages and power flows at substations and other key locations such as DG sites by virtue of the communication interface with RTUs are used by a GenAVC system which in turn estimates voltages across the network and provides voltage targets for primary transformers via the interface with AVCs. The objective of this scheme is to efficiently utilise the network while keeping voltages at various points of a network inside statutory limits to support DG connections to the grid. The cost of implementation of a GenAVC scheme is expensive yet cheaper than network reinforcement [158].

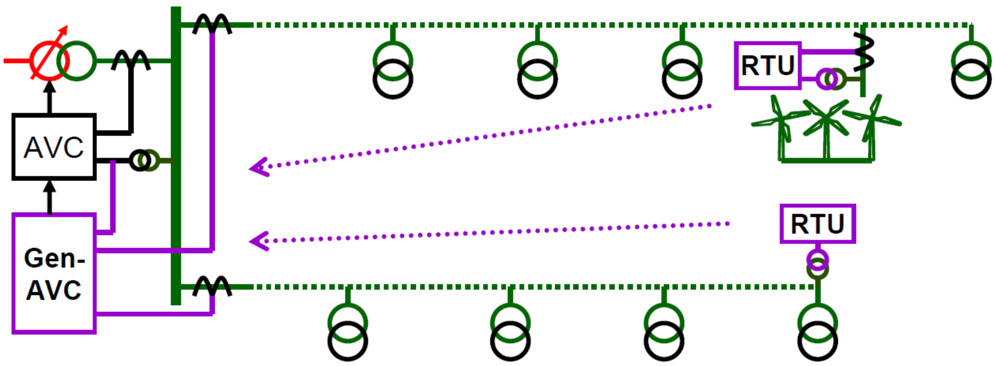


Figure 3-11 GenAVC voltage control scheme ([159])

The limitation with GenAVCs' applications is that the network model used for voltage evaluation is not synchronised with the current network operation conditions, i.e. any change in network configurations whether planned or unplanned would require the scheme to be disconnected and adapted to changed conditions [58]. Another disadvantage is the scheme's strong dependence upon communication links between DGs and substations; no backup control is incorporated within the scheme to cope with the loss of data communication.

3.2.3.2 SuperTAPP n+ Voltage Control Relay

The SuperTAPP n+ voltage control relay (VCR) is a self-monitoring device that can automatically regulate up to six under-load tap changing transformers connected in parallel. The fundamental objective of the SuperTAPP n+ VCR is to safely regulate voltage levels across distribution networks by considering DGs' current contribution while diminishing the circulating current flowing through paralleled transformers [160]. Figure 3-12 shows a schematic diagram illustrating the SuperTAPP n+ VCR scheme used in distribution networks. It incorporates the LDC function and also deals with voltage rise issues and lowers the set point voltages on the basis of substation measurements (voltage and current of transformers and current of each outgoing feeder), estimated current contributed by DGs and the estimated total load on feeders [161].

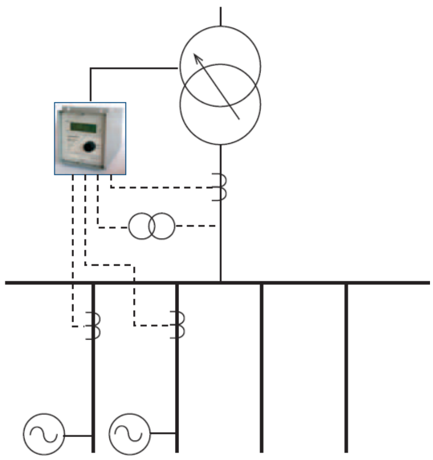


Figure 3-12 SuperTAPP n+ VCR [162]

SuperTAPP n+ VCRs' functionalities are particularly useful when a DG is being connected to a distribution feeder. However, the cost implications from the relay's resultant control operations with respect to the tap changer movements are unclear and the robustness and accuracy of the voltage estimation algorithm still need to be verified as the number of DG connections keeps increasing for complex network configurations. One of the limitations of the SuperTAPP n+ VCR scheme is that load measurements at DG connection points need to be taken when generators are disconnected. If DGs are already connected to the grid, these measurements will be dependent on the intermittent output from renewable resources and may not be accurately indicative of the network conditions. Hence the robustness of the scheme needs to be verified overtime.

3.3 Reactive Power Compensation

In power systems, load and transformers are the major consumers of reactive power; reactive power can be generated by regulated sources or naturally provided by certain equipment [2].

3.3.1 Reactive Compensators in Power Systems

Typical reactive power sources and consumers are illustrated in Figure 3-13.

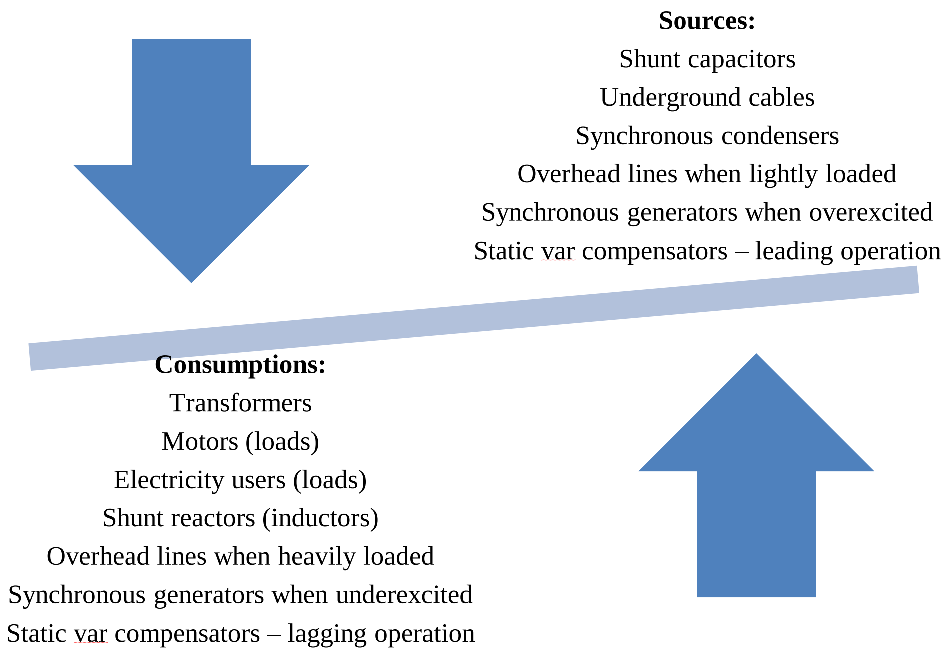


Figure 3-13 Reactive power sources and consumptions

Consumer loads

Most loads consume reactive power by producing magnetic fields such as motors and heating appliances [2]. Usually a number of loads are connected to a load bus and the aggregated characteristics normally indicate that reactive power is consumed by load buses. Power factors of loads typically imply how much reactive power are required and voltage drops along transmission lines and distribution feeders are dependent on these factors. Considering that reactive power is supplied locally, it is preferred by network operators that the majority of loads should maintain a power factor close to unity. In the UK, whilst active power demand has decreased to a small scale, a significant drop in reactive power demand has been observed by NGET, which could potentially lead to voltage rise issues [163]. The reasons for this phenomenon are currently under investigation.

Overhead lines & underground cables

Reactive power is generated by overhead lines due to the electric fields produced when the loads are less than the natural (surge impedance) load and it is absorbed by virtue of the magnetic fields caused by the current flowing along the lines when loads are greater than the natural load [2]. Reactive power is always generated by underground cables because their natural loads are quite high due to high capacitance and loads are always lower than the natural loads.

Reactive power compensators

Some utilities categorise reactive power compensators as static and dynamic support. Static reactive power compensation is provided to power systems when connected to the grid and slowly changes the reactive power levels [2]. Dynamic reactive power compensators can quickly provide reactive support such as synchronous condensers. Reactive support can also be categorised as passive and active compensation: capacitors and reactors modify characteristics of lines or cables as passive compensators whilst synchronous condensers, Static Var Compensators (SVCs) and other controllable reactive resources are regarded as means of active compensation by automatically changing reactive output to maintain desired voltage levels.

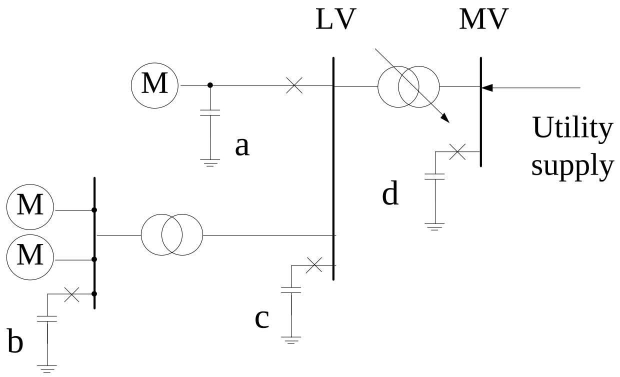
Table 3-3 is a summary of the reactive compensation equipment commonly found in transmission and distribution systems. Series capacitors and series reactors are not included in the table because their major function is to modify the characteristics of line impedance. Amongst the equipment listed in the table, shunt capacitors and shunt reactors are the most cost-effective reactive compensation equipment used in distribution networks [2], as introduced following the table.

Table 3-3 Reactive compensation equipment commonly used in power systems ([2][127][164])

	Characteristics	Major applications
Shunt capacitors	• Generate reactive power passively • Provide power factor correction and feeder voltage control • To reduce the effective characteristic impedance of lines	• Mechanically switched or fixed shunt capacitor banks at substations in transmission & distribution systems or the end of distribution feeders • Connected to tertiary windings of three-winding transformers
Shunt reactors	• Absorb reactive power passively • Compensate the capacitive load of transmission lines • Reduce voltage rise at light load • Disconnected at heavy load	• Mechanically switched or fixed shunt reactors at OHLs (>200km) in transmission systems (connected to tertiary windings of transformers or busbars) and at underground cables at distribution networks
Synchronous condensers	• Active compensation – controllable output • Provide only reactive power	• Connected to tertiary windings of transformers in transmission systems; installed at the receiving end of long transmission lines
SVCs	• Active compensation – quicker than synchronous condensers • Fast switching of capacitors and reactors • Production or consumption of reactive power	• Mostly used in transmission systems, especially at the busbars to which a cluster of lines are connected that require reactive power support
STATCOM	• Active compensation – quicker than SVCs but higher losses • Production or consumption of reactive power • Fast switching of capacitors and reactors	• STATCOM for transmission systems • DSTATCOM for distribution systems

Shunt Capacitors

Shunt capacitors generate reactive power by producing electric fields and thereby raise local voltages [2]. Shunt capacitors come in a wide range of sizes at high and low voltage levels and have been readily deployed at demand side, transmission systems and distribution networks at various points, as shown in Figure 3-14.

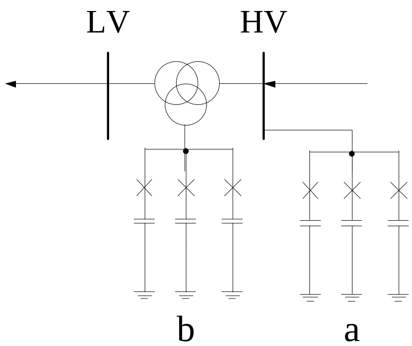


(i) Shunt capacitors used by industrial plants at distribution networks

a: individual compensation

b: group compensation

c, d: plant compensation



(ii) Shunt capacitor banks in transmission systems

a: HV capacitor banks connected to an HV busbar

b: capacitor banks connected to the tertiary transformer winding

Figure 3-14 Shunt capacitor applications to distribution and transmission systems (adapted from [2])

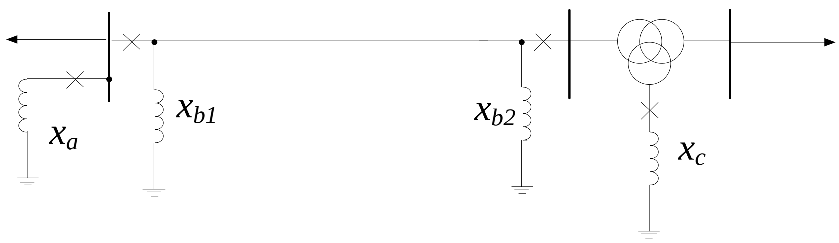
At distribution networks, shunt capacitors are typically used for feeder voltage control at substations or for power factor correction at demand side. Shunt capacitors are adopted by large customers such as industrial plants to improve their local power factors because low power factors increase voltage drops along distribution feeders and it is more cost-effective to supply reactive power locally than from remote synchronous generators. It can be seen from plot (i) in the figure that capacitors at industry plant sites are connected to the grid individually or in group, at the MV or the LV side of a distribution substation. Shunt capacitors are utilised at transmission systems to compensate reactive power losses and to maintain required voltage levels; shunt capacitors are normally connected to the HV, LV or the tertiary side of a three winding transformer.

There are two primary types of shunt capacitors: fixed and switchable. Fixed shunt capacitors are permanently directly connected to distribution feeders at 11kV where low voltages tend to occur owing to heavy loads [2]. Switchable capacitors can take two forms: mechanically switched capacitors (MSCs) that are switched by dedicated circuit breakers and thyristor switched capacitors (TSCs) that are connected to networks by thyristor valves. MSCs and TSCs are known as an economical measure to compensate reactive power by virtue of low costs and flexible installation and operation, compared with dynamic compensators such as SVCs and STATCOMs. MSCs are the most commonly used switchable capacitors throughout power systems because of its simplicity and flexibility. In the UK power systems, single capacitor banks typically constitute the MSCs that are connected to transmission systems at the voltage level of 275kV or higher; the switching action is achieved via the individual circuit breakers [165]. At voltage levels of 132kV or lower, MSCs typically comprise of a number of capacitor banks and are connected to power grid via each capacitor bank's circuit breaker or a common circuit breaker that connects or disconnects all of the capacitor banks. Certain automatic control strategies may be used to regulate MSCs by monitoring network parameters at substations locally in response to the drop of voltage levels.

The major limitation of shunt capacitors is that the reactive power output provided by a shunt capacitor is in proportion to the square of the local voltage, consequently the reactive support may not be sufficient at times of low voltages [2]. In addition, the switching action of MSCs entails voltage step changes and influences power quality; such issues are addressed during the designing stage prior to installing an MSC and tackled by certain control schemes when in operation.

Shunt Reactors

Shunt reactors can lower voltage drops over long distance extra-high voltage (EHV) transmission lines (usually longer than 200km) or heavily meshed parts of a network with shorter lines by compensating the capacitance of transmission lines when the system is lightly loaded, in which case, excessive reactive power generated by transmission lines is absorbed by shunt reactors [2]. Shunt reactors are also used for compensating reactive power for high voltage underground cables in distribution systems. Most of shunt reactors (30-300MVAr) are usually directly connected to high voltage busbars or transmission lines; they are normally switched on when the system is lightly loaded and switched off when heavily loaded using disconnect switches or circuit breakers. Shunt reactors with a low voltage rating (>100MVAr) are normally connected to tertiary windings of power transformers. These shunt reactors are disconnected when the system is heavily loaded. Connections of shunt reactors to the grid are illustrated in Figure 3-15.



X_a: shunt reactor connected to busbar

X_{b1},X_{b2}: shunt reactors connected to transmission lines

X_c: shunt reactor connected to tertiary wind of a transformer

Figure 3-15 Shunt reactor connections in power systems (adapted from [2])

As opposed to MSCs, mechanically switched reactors (MSRs) are widely used to consume excessive reactive power in power systems [2]. For certain EHV transmission lines that serve loads lower than their natural load, shunt reactors are permanently connected to the lines, also known as fixed shunt reactors. In distribution networks, shunt reactors are also required for long distance HV cables in order to prevent undesired voltage rise by counteracting the high capacitive charging current, particularly when a high load is suddenly disconnected. Considering their inherent effect on overhead lines, combining shunt capacitors and series capacitors can enable independent controls over effective characteristic impedance and the load angle. This may be a useful type of reactive compensation in some cases, for example, a long line that requires high effective natural impedance and a low phase angle.

3.3.2 Control Practice for Reactive Compensators

Practically, in the UK power systems, a strategy known as the automatic reactive switching (ARS) scheme is utilised to regulate the MSCs and MSRs at the voltage of 66kV and above [166]. The ARS software is normally applied on a dedicated microprocessor and the primary objective of the scheme is to meet system requirements for voltage control by automatically switching capacitors and reactors as appropriate under pre-fault and post-fault conditions rather than by relying on manual intervention. The operation of MSCs under normal (pre-fault) conditions supplies reactive power and thus keeps voltage profiles at a relatively high level by providing MVArs reserves and enhances voltage profiles at the transient period following the occurrence of a system fault. The number of MSCs that are connected to grid under steady state conditions is also limited so as to avoid system overvoltages caused by big voltage step changes considering that some capacitor banks are controlled by a common breaker. Under post-fault cases, some MSCs are connected to the grid to improve voltage performances with a time delay, usually before the reaction of transformer tap changers. The ARS scheme comprises of a number of control modes to meet the voltage requirements; the major operation modes for ARS schemes are introduced in the order of priority in Table 3-4.

Table 3-4 Major control modes for ARS schemes ([166])

Mode of operation	*Reference regarding capacitors*
Protection mode	The voltage at the busbar where capacitors/reactors are connected is monitored and capacitors are switched out if the voltage is higher/lower than certain preset thresholds such as Fairly High LV Voltage, High LV Voltage and Very High LV Voltage
Coarse voltage control mode	Capacitors are fast switched on to deal with large excursions in the voltage at the HV side of the three winding transformer where capacitors or reactors are connected.
Manual mode	Operators directly actuate the switching action to fine-tune the system to ensure that an appropriate number of capacitors are connected to grid under pre-fault conditions.
DeltaLV mode *	The voltage step change due to the opening of a common circuit breaker is predicted based on the most recent voltage measurements so that switching actions due to fine voltage control mode can be avoided to meet the requirements of voltage step change.
External inhibits *	The number of MSCs in reserve is determined to limit the total number of connected MSCs.
Flicker inhibits *	The voltage step change due to each switching action is monitored to keep the Fine Voltage Control Mode from exceeding the required flicker limits.
Fine voltage control mode	Capacitors are slowly switched on to maintain the voltage at the HV side of the three winding transformer where capacitors/reactors to be within a preset deadband. The switching process is delayed to not respond to temporary fluctuations and also to coordinate with DAR and AVC schemes to make sure switching actions occur after DAR and before AVC.

Note:

The control modes marked by '*' has the same priority level.

Inputs to the above control modes involve voltage measurements at the primary, secondary and tertiary windings of the transformer where the capacitors and reactors are connected, voltage step changes and the switch status information as well as protection signals [166]. The action of switching off is relatively preferred than the action of switching on by the ARS. For instance, when it is required by one of the control modes that a capacitor should be switched on or a reactor should be switched off, the ARS switches off any currently connected reactors before switching on any capacitors. If the same switching action is commanded by two or more control modes but with different time delays, the ARS checks if the slower switching action is still required as time progresses and only actuate the switching if necessary.

ARS schemes are supposed to coordinate with transformer AVC schemes due to the interference between the two types of schemes in terms of voltage settings and equipment response time. Firstly, the target voltage set by the AVC scheme should always be lower than the 'Fairly High LV' threshold for the ARS scheme; otherwise protection mode will not permit any capacitors to be connected to avoid over-voltages. Secondly, MSCs switching actions via circuit breakers are relatively faster than transformer tap changers' response to AVC voltage settings via driver mechanisms. Therefore, an appropriate time delay in transformers' response is necessary. For instance, a 'tap stagger off' signal is sent to the AVC whenever a switching request of 'capacitor on/reactor off' is executed by the ARS scheme. Furthermore, the voltage step change caused by the switching action of an MSC or an MSR are relatively greater than that caused by a tap changer operation; one switching action may be sufficient to improve the local voltage level and the time delay will prevent transformer tap changers from unnecessary response.

3.3.3 Reactive Power Planning

RPP is a subset of of power system planning as described in section 2.2. Analytically, reactive power management addresses enhanced utilisation of existing compensation equipment and planning of new equipment in terms of siting and sizing [127]. Specifically, the following control mechanisms are concerned: generator terminal voltage control, transformer tap settings as well as the dispatch or allocation of reactive power compensation by switchable capacitors and reactors. Power utilities normally consider the dispatch and control of reactive power at snapshots and also the planning of reactive power compensation. Analytically, the operation of reactive equipment is determined via dispatch and control algorithms and system analysis is performed from seconds to hours before the execution of actions.

Planning of reactive power support looks into the installation or disposal of compensation equipment in the coming months or years, by identifying the amount of MVAr compensation required, an optimum location of reactive compensators and the installation date [167]. The objective of RPP is to minimise the total costs of using reactive compensators, which is often treated as an optimisation problem with system security constraints taken into account under both pre-fault and post-fault conditions. System security regarding voltage levels and economics are the key factors considered by power industry utilities for planning and operation of reactive power compensators [127]. It is a common practice that voltages at important locations are monitored by metering devices and the information together with off-line analysis is used by operators to manage the performance of system voltages. Unlike RPP, RPD aims at optimally coordinating the available voltage control equipment such as ULTC transformers, generator AVRs and shunt capacitors and reactors [167]. Whilst RPP looks into a relatively longer time period, RPD is only concerned about the use of reactive compensators at snap shots. Short-term scheduling or planning of reactive power is concerned about the dispatch of reactive compensators for a relatively shorter time period such as 24 hours ahead of real time.

3.4 Cost Analysis of Voltage Control

There may be different ways to analyse the operational costs incurred by control actions such as the movements of transformer tap changers or switching actions of capacitors or reactors, because these control actions often have a number of cost implications. That is, frequent movement or switching operations over time might advance the periodic maintenance intervals, increase the failure rate or even cause the life expectancy of equipment to be shortened, due to the technical risks the switching actions impose upon the equipment. For instance, the timing of maintenance for under-load tap changers typically depends upon the total number of tap-changing operations and the regular maintenance interval, whichever is reached first [168]. Specifically, oil-type under-load tap-changers are typically maintained every 100,000 operations or every 7 years; vacuum-type under-load tap-changers have an extended maintenance interval of every 300,000 operations but at a relatively higher capital cost [169]. Equipment operated by moving or switching mechanical parts typically has a limited number of moving or switching operations throughout its lifetime. For simplicity, the economic costs of control actions considered in this thesis are assumed to be primarily made up of explicit costs, i.e. the capital costs of assets; the cost of each control action is assumed to be the depreciated capital cost. Capital costs of power system equipment normally vary by manufacturers and location. It should be noted that, due to the commercial sensitivity of the capital costs for power system assets, these figures are typically not readily available in the public domain, as far as the UK is concerned.

3.4.1 Transformer Tap-changing Cost

The control cost of transformer tap-changing operations may be calculated based on the cost of replacing the tap changer or the cost of replacing the tap-changing transformer depending on the physical arrangement of the tap changer. Although under-load tap changers account for about 5-10% of the capital cost of transformers, the operation of tap changers plays a crucial part in maintaining a satisfactory level of the availability rate and the life span of the transformer [170]. In other words, the life cycle of a transformer is closely related to tap changer performance. ULTC transformers typically have a limited number of tap changing operations during its lifetime and during its maintenance intervals, whether the tap changers are oil-type or vacuum-type. Control cost caused by each tap step change is derived by the capital cost of an ULTC transformer divided by its maximum allowed number of tap changing operations, expressed as £/tap change [171]. [16]

[16] The tap-changing operation as defined in the “maximum allowed number of tap changing operations” depends on the type of the tap changer. It could refer to the incremental tap position change for mechanical tap changers and any change in positions for electronic tap changers.

For instance, for a 66/20kV 20MVA ULTC transformer, assuming that its capital cost is £150,000 [172] and the maximum allowed number of tap changing operations during its lifetime is 500,000, the control cost of each operation is £0.3 per tap position change. The number of expected tap-changing operations can also be calculated on the basis of the number of operations per day: an average of 35 tap changes per day [173] for 40 years means a total of 511,000 tap-changing operations. If each tap step change is an incremental tap change equivalent to 1.25% tap ratio change, the control cost per ratio change will be £24/tap ratio. The same analytical method can be applied to calculate the maintenance cost per tap change, which will be the total maintenance cost divided by the expected number of tap changing operations that are allowed to occur between two maintenance periods. Since mechanical-type tap-changers can only be operated step-by-step, the use of control cost per incremental tap change or per tap ratio will be appropriate to calculate the total costs over time [139]. Electronic tap-changers, however, are able to move from the lowest tap position to the highest in one step change, which makes the control cost per tap operation more suitable. Considering that the UK distribution networks were firstly developed in the 1960s and 1970s when the idea of electronic tap changers was only beginning to take shape, most of the substation transformers in distribution systems have mechanical tap changers [58]. Therefore, the control cost per tap change that is used in the case studies in this thesis refers to the cost for each incremental position change.

3.4.2 MSC/MSR Switching Cost

'Switchable' equipment such as MSCs and MSRs normally allows a limited number of switching operations throughout their life expectancy, due to the mechanical wear-and-tear the switching actions have on the equipment [171]. Therefore, the control cost of each switching action represents a depreciated asset cost, i.e. the capital cost of assets divided by the maximum number of switching operations over the lifetime of the equipment, expressed as £/switching action. The number of switching operations for many MSC applications is about 2 to 4 times per day [174], in which case the total number of expected switching operations will be about 29,200 to

58,400 times for 40 years of service (without considering the availability factor of the asset). For a 100MVAr MSC at 400kV with a capital cost of £3,000,000 [175], the switching cost will be £51.37 for a total number of 58,400 switching operations.

Considering that the switching action of an MSC is normally done via a dedicated circuit breaker [165], it may also be appropriate to calculate the switching cost based on the cost of replacing the circuit breaker rather than the MSC. For an MSC that has a number of individual capacitor banks, there may be an individual breaker for each capacitor bank as well as a common circuit breaker for all the banks [165]. As a result, the calculation of cost of each switching action can be made up of control costs imposed on a number of breakers. For simplicity, it is assumed that each of the MSCs used in distribution networks has an individual capacitor bank and therefore one circuit breaker. The cost of each control action for MSCs used in the case studies in chapter 9 was assumed to be the cost of replacing the circuit breaker divided by the number of expected switching actions.

According to the 33kV substation plant strategy by Scottish Power Energy Networks [176], the average cost of replacing a 33/11kV transformer is around £173.03k and therefore the cost per tap-changing action is around £0.346 for a maximum number of 500,000 operations. The 11kV substation plant strategy [177] suggests that the average cost of replacing an 11kV circuit breaker is about £31.89k, in which case the cost per switching action is about £0.546 for a total number of 58,400 operations. Given that the cost per switching action for an MSC is greater than the cost per tap-changing operation for an ULTC transformer, the proposed methodology would always try to use the cheaper option, i.e. the MSC will not be scheduled unless the transformer tap changing operations have been exhausted. It is assumed in case study 1d, 1e and 2c (in Chapter 6) that the switching cost for an MSC is cheaper so as to enable the proposed methodology to make use of the MSC to improve voltage profiles. Since the focus of this thesis is on the utilisation of the most cost-effective control actions to deal with voltage control problems, it is more important to use the relative costs of control actions rather than the monetary costs.

3.4.3 Generator Reactive Power Cost

The explicit cost for a synchronous generator to produce reactive power is primarily made up of the capital cost which corresponds to the capacity used for MVAr output [171]. The capital cost of a generator *C(P)* is normally expressed as £/MW. The capital cost of reactive power *C(Q)* in terms of £/MVAr can be derived as follows, given the nominal power factor *p.f.* of the generator.

$$C(Q) = \frac{C(P)}{\cos\varphi}\sin\varphi = \frac{C(P)}{pf}\sin(cos^{-1}(p.f.)) \tag{3-18}$$

where φ is the angle difference between voltage phasor and current phasor at the nominal power factor *p.f.*

Due to practical constraints on generator's reactive power capability, the capacity that the generation of reactive power requires could have been used in other ways that will provide more value. The potential highest value of other uses of generation capacity is regarded as the opportunity cost and involves electricity market variables. The calculation method for deriving the opportunity cost can be found in [171].

3.5 Practical Challenges for Voltage Control

Voltage regulation of distribution networks is achieved by methods out of the following: substation busbar voltage regulation by ULTC transformers, distribution feeder regulation at the substation and supplementary regulations at selected points on the long distance feeders [2]. In the UK, the available information and controls that distribution substations hold becomes less from the 132kV systems to 11kV and below, as indicated in Table 3-5. It can be summarised from this table that the majority of distribution substations are equipped with little or no tele-control or data indications. It is impractical to manually actuate the secondary transformers considering the large amount of substations and controls are executed at relatively higher voltage levels [39].

Table 3-5 Substation controls at distribution substations in the UK ([39])

Substations	*Available information/control*		*Comments*
Grid substations (132/33kV)	132kV • Telecontrol of all circuit breakers • Analogue data on all feeders • Robust communication links	• Digital alarms and indicators for all equipment • Highlight of faults via protection operation indications to control rooms	• <1% of all UK substations • Approx. 22,000 customers per substation
	33kV • Telecontrol of the majority of circuit breakers • Analogue data on all feeders	• Digital alarms and indicators for newer equipment • Highlight of faults via protection operation indications to control rooms	
Primary substations (33/11kV)	33kV • Telecontrol over the majority of circuit breakers • Analogue data on the majority of feeders	• Digital alarms and indications – as above • Faults – as above	• Around 4.0% of UK substations • Supplying around 3,000 customers per substation
	11kV • Telecontrol on circuit breakers (for substations built after 1985) • Some analogue data at primary substation	• Majority of digital alarms and indications available • Fault highlighted to control room upon opening of a circuit breaker	
Secondary substations (11kV/LV)	11kV • Little/No telecontrol/analogue data/digital alarms and indications • Customers report 'power cut'		• Around 95% of UK substations • Supplying around 3,000 customers per substation
	LV • No remote information		

The voltage control practice currently in use in the GB distribution systems is shown in Table 3-6. Considering that secondary transformers lack under-load tap changers, the voltage targets of AVC schemes at 11kV networks should be set such that the voltage on the lowest point of the 415V system is not too low.

Table 3-6 Existing voltage control practice in GB distribution systems ([39])

Name	*Component*	*Characteristics*	*SCADA/Local*
AVC	132/33k transformers at grid substations	• Range of settings depends on the tapping limits; • Regulating point is 33kV; • Limited SCADA interface; • Capability to operate at fixed power factor	Auto local & SCADA
AVC	33/11kV transformers at primary substations	• Range of settings depends on the tapping limits; • Regulating point is 11kV; • LDC may be used when necessary; • CCC/RCC schemes etc.	Auto local
In-line voltage regulators	11kV feeder	• Two single-phase connected regulators that control the line voltage on 11kV networks where wind turbines are connected to quickly react to voltage changes; • The value of DB can be monitored to coordinate with generators and AVC at primary substations; • Very few applications to the network	Auto local (possible SCADA use)
Manual tap changers	11kV/LV transformer at secondary substations	• Off-line tap changer; • Typically only changed to ensure voltage profiles down a feeder remains inside statutory limits	Manual
Capacitors	At substations/ Along feeders	• Supply reactive power to raise local voltage levels; • Limited usage throughout the UK	Fixed (few switched in steps)

Current control practices set the tap steps and AVC DB settings to enable more tap movement on the primary substation transformers than the grid transformers [39]. 11kV voltage targets in AVC schemes should be set on the basis of past experience such that the voltage on the lowest point of the 415V system is not too low. In addition, the 11kV network feeders are becoming populated by DGs and local voltages are subject to changes, which is likely to require a change in the way that current voltage regulations are executed.

3.6 Summary

This chapter has addressed the importance of voltage regulation in distribution networks, described voltage drops along distribution feeders in distribution networks, discussed the relationship between voltage and reactive power and introduced a number of typical voltage control equipment and control practice commonly used in distribution systems. This chapter has highlighted that, automated voltage control mechanisms and monitoring devices only exist at the AC systems from 400kV to 11kV in the UK power systems. DNOs still need to explore the options to improve the voltage performance for consumers connected at voltage levels below 11kV.

4. Review of Voltage Control Approaches

This chapter introduces linear sensitivity analysis of power systems which has been extensively used for RPD and voltage control problems in existing publications and serves as the basis of the proposed methodology in this thesis. A critical literature review of the state-of-the-art publications is presented in this chapter in three categories: conventional optimisation methods, AI-related and other methods and the methods that particularly considered the time-varying nature of network demand.

4.1 Linear Sensitivity Analysis

Sensitivity analysis has been extensively used for voltage and frequency studies and often used with other techniques such as linear programming and artificial intelligence methods [48]. Linear sensitivity coefficients, usually expressed as partial derivatives, represent the approximate change in a dependent variable as an independent variable changes. Linear sensitivities are normally calculated on the basis of Jacobian matrices of a standard N-R load flow programme. Sometimes these sensitivities can also be computed based on simplified FDLF algorithms. These coefficients are particularly useful in linear programming for OPF studies and power system contingency analysis.

4.1.1 General Formulation of AC Power Flow

For a power system with N buses, the current injection at a bus k can be represented as the summation of the multiplication of admittance and voltage at each bus from *1* to n as follows.

$$I_k = Y_{k1}V_1 + Y_{k2}V_2 + \cdots + Y_{kn}V_n = \sum_{n=1}^{N} Y_{kn}V_n \tag{4-1}$$

where I_k is the current flowing into bus k, Y_{kn} is the admittance between bus k and bus n and V_n is the voltage at bus n.

To represent all the buses in a power system, a matrix equation can be formed based on (4-1) and presented as *[I] = [Y][V]*, where *[I]* is the singular matrix for bus current injections, *[Y]* is the bus admittance matrix and *[V]* the singular matrix for bus voltages [1, pp. 305–311]. Voltage vectors are noted as below:

$$V_{kn} = |V_{kn}|e^{j\delta_{kn}} \tag{4-2}$$

where $|V_{kn}|$ is the magnitude of the voltage, δ_{kn} is the phasor angle of the voltage.

The bus admittance matrix *[Y]* is composed of conductance *G* and susceptance *B* as shown below:

$$Y_{kn} = |Y_{kn}|e^{j\theta_{kn}} = G_{kn} + jB_{kn} \tag{4-3}$$

where is $|Y_{kn}|$ the magnitude of the admittance between bus *k* and bus *n*, θ_{kn} is the phasor angle of the admittance.

The bus admittance matrix *[Y]* is calculated on the basis of line and transformer data as well as shunt capacitors and shunt reactors:

$$\begin{gathered} Y_{kn} = -\sum y_{kn} \\ Y_{kk} = \sum_{n}^{N} y_{kn} + y_{kg} \end{gathered} \tag{4-4}$$

where Y_{kn}, and Y_{kk} represent the off-diagonal and diagonal elements of the bus admittance matrix, i.e. the mutual admittance and self-admittance; y_{kn} represents the admittance of the conductor between bus *k* and *n*; y_{kg} represents the shunt admittance connected to bus *k*.

The apparent power of a busbar *k* given voltage V_k and current I_k is formulated based on equation (4-1) as below:

$$S_k = P_k + jQ_k = V_k I_k^* = V_k \left(\sum_{n=1}^{N} Y_{kn} V_n \right)^* \tag{4-5}$$

where P_k and Q_k are the active and reactive power flowing through the busbar *k* respectively.

Since the active and reactive power is the real and imaginary part of the apparent power S_k, their injections at bus k are calculated using the following two equations based on equation (4-3) and equation (4-5).

$$P_k = Re[V_k^* \sum_{n=1}^{N} Y_{kn} V_n] = |V_k| \sum_{n=1}^{N} |V_n| (G_{kn} \cos \delta_{kn} + B_{kn} \sin \delta_{kn}) \quad (4\text{-}6)$$

$$Q_k = -Im[V_k^* \sum_{n=1}^{N} Y_{kn} V_n] = |V_k| \sum_{n=1}^{N} |V_n| (G_{kn} \sin \delta_{kn} - B_{kn} \cos \delta_{kn}) \quad (4\text{-}7)$$

where G_{kn} and B_{kn} are the conductance and susceptance part of the Y admittance matrix at the row k and column n, δ_{kn} is the voltage angle difference between the bus k and bus n [1].

Due to the non-linearity of the load flow problem, iterative methods have been adopted to linearise the problem and to obtain a satisfactory solution by setting initial conditions and an error threshold; load flow calculations are performed until the mismatch between two iterations becomes smaller than the required threshold. A number of algorithms have been used to solve the load flow problem: Gauss-Seidel (G-S) algorithm, Newton-Raphson (N-R) algorithm, fast decoupled load flow (FDLF) and DC load flow and DC load flow. In particular, N-R load flow and FDLF techniques are the most commonly applied load flow techniques in EMS because of their fast convergence rate, less computer storage and robust solutions

4.1.2 Newton-Raphson Method

N-R method is based on Taylor series expansion and iterative calculations of errors. This algorithm begins with an initial guess of all unknown variables, voltage magnitudes and angles at PQ buses and voltage angles at PV buses [48]. A Taylor Series with the higher order terms ignored of each of the power balance equations is written, resulting in a linear system of equations expressed as follows:

$$\begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} = -J^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \quad (4\text{-}8)$$

where ΔP and ΔQ are called the mismatch equations, shown as below.

$$\Delta P_k = -P_k + \sum_{n=1}^{N} |V_k||V_n|(G_{kn} \cos\delta_{kn} + B_{kn} \sin\delta_{kn}) \tag{4-9}$$

$$\Delta Q_k = -Q_k + \sum_{n=1}^{N} |V_k||V_n|(G_{kn} \sin\delta_{kn} - B_{kn} \cos\delta_{kn}) \tag{4-10}$$

J in equation (4-8) is a matrix of partial derivatives named a Jacobian shown in equation (4-11):

$$\boldsymbol{J}(\boldsymbol{x}) = \begin{bmatrix} \frac{\partial f_1}{\partial x_1}(x) & \frac{\partial f_1}{\partial x_2}(x) & \cdots & \frac{\partial f_1}{\partial x_n}(x) \\ \frac{\partial f_2}{\partial x_1}(x) & \frac{\partial f_2}{\partial x_2}(x) & \cdots & \frac{\partial f_2}{\partial x_n}(x) \\ \vdots & \ddots & \ddots & \vdots \\ \frac{\partial f_n}{\partial x_1}(x) & \frac{\partial f_n}{\partial x_2}(x) & \cdots & \frac{\partial f_n}{\partial x_n}(x) \end{bmatrix} = \begin{bmatrix} J_{11} & J_{12} \\ J_{21} & J_{22} \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial V} \end{bmatrix} \tag{4-11}$$

where the non-diagonal elements of the Jacobian matrices J_{11}, J_{12}, J_{21} and J_{22} are calculated using the following equations,

$$J_{11} = V_k Y_{kn} V_n \sin(\delta_k - \delta_n - \theta_{kn}) \tag{4-12}$$

$$J_{12} = V_k Y_{kn} \cos(\delta_k - \delta_n - \theta_{kn}) \tag{4-13}$$

$$J_{21} = -V_k Y_{kn} V_n \cos(\delta_k - \delta_n - \theta_{kn}) \tag{4-14}$$

$$J_{22} = V_k Y_{kn} \sin(\delta_k - \delta_n - \theta_{kn}) \tag{4-15}$$

and the diagonal elements of the Jacobian matrices J_{11}, J_{12}, J_{21} and J_{22} are calculated based on the following equations:

$$J_{11} = -V_k \sum_{\substack{n=1 \\ n \neq k}}^{N} Y_{kn} V_n \sin(\delta_k - \delta_n - \theta_{kn}) \tag{4-16}$$

$$J_{12} = V_k Y_{kk} \cos\delta_{kk} + \sum_{n=1}^{N} Y_{kn} V_n \cos(\delta_k - \delta_n - \theta_{kn}) \tag{4-17}$$

$$J_{21} = V_k \sum_{\substack{n=1 \\ n \neq k}}^{N} Y_{kn} V_n \cos(\delta_k - \delta_n - \theta_{kn}) \tag{4-18}$$

$$J_{22} = -V_k Y_{kk} \sin\delta_{kk} + \sum_{n=1}^{N} Y_{kn} V_n \sin(\delta_k - \delta_n - \theta_{kn}) \tag{4-19}$$

The equations are solved to determine the next guess *(i+1)* of voltage magnitude and angle based on the following equations.

$$V_{i+1} = V_i + \Delta V \tag{4-20}$$

$$\delta_{i+1} = \delta_i + \Delta\delta \tag{4-21}$$

Usually, a tolerance level of convergence is given and this iterative process goes on until the specified stopping condition is satisfied.

4.1.3 Fast Decoupled Load Flow

Although robust, N-R algorithm is a lengthy process since the Jacobian matrix along with the entire set of equations must be recalculated as the algorithm iterates. A simpler load flow algorithm was introduced to speed up the calculation via decoupled and simplified Jacobian matrix, which is known as the FDLF [48]. Due to the relatively weaker coupling between active power and voltage magnitude, reactive power and voltage angle, the off diagonal sub-matrices J_{12} and J_{21} in equation (4-11), are neglected, leaving only two sets of decoupled equations.

$$\Delta P = \frac{\partial P}{\partial \delta}\Delta\delta = J_{11}\Delta\delta \tag{4-22}$$

$$\Delta Q = \frac{\partial Q}{\partial V}\Delta V = J_{22}\Delta V \tag{4-23}$$

Further assumptions listed as below are usually made to further reduce the required computer calculation time.

$$V_k \approx 1.0\ per\ unit \tag{4-24}$$

$$\delta_k = \delta_n \tag{4-25}$$

$$G_{kn} sin(\delta_k - \delta_n) \ll B_{kn} \tag{4-26}$$

$$Q_k \ll B_{kn}V_n^2 \tag{4-27}$$

Therefore, the derivatives in the original Jacobian matrices in equation (4-11) become:

$$\frac{\partial P_k}{\partial \delta_n} = -V_k B_{kn} \tag{4-28}$$

$$\frac{\partial Q_k}{\partial V_n} = -V_k B_{kn} \tag{4-29}$$

Two simplified Jacobian matrices can be obtained, relating active power to voltage angles and reactive power to voltage magnitudes:

$$\begin{bmatrix} \frac{\Delta P_1}{V_1} \\ \frac{\Delta P_2}{V_2} \\ \vdots \end{bmatrix} = \begin{bmatrix} -B_{11} & -B_{12} & \vdots \\ -B_{21} & -B_{22} & \vdots \\ \vdots & \vdots & \vdots \end{bmatrix} \begin{bmatrix} \Delta\delta_1 \\ \Delta\delta_2 \\ \vdots \end{bmatrix} \tag{4-30}$$

$$\begin{bmatrix} \frac{\Delta Q_1}{V_1} \\ \frac{\Delta Q_2}{V_2} \\ \vdots \end{bmatrix} = \begin{bmatrix} -B_{11} & -B_{12} & \vdots \\ -B_{21} & -B_{22} & \vdots \\ \vdots & \vdots & \vdots \end{bmatrix} \begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \vdots \end{bmatrix} \tag{4-31}$$

Further assumptions can be made about line impedances and shunts.

$$r_{kn} \ll x_{kn} \tag{4-32}$$

$$-B_{kn} = -\frac{1}{x_{kn}} \tag{4-33}$$

By ignoring the effects from phase shifting transformers, shunt reactance, equation (4-34) and equation (4-35) are derived.

$$\begin{bmatrix} \frac{\Delta P_1}{V_1} \\ \frac{\Delta P_2}{V_2} \\ \vdots \end{bmatrix} = [B'] \begin{bmatrix} \Delta\delta_1 \\ \Delta\delta_2 \\ \vdots \end{bmatrix} \tag{4-34}$$

$$\begin{bmatrix} \frac{\Delta Q_1}{V_1} \\ \frac{\Delta Q_2}{V_2} \\ \vdots \end{bmatrix} = [B''] \begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \vdots \end{bmatrix} \tag{4-35}$$

where

$$\begin{gathered} B'_{kn} = -B_{kn} = -\frac{1}{x_{kn}} \\ B'_{kk} = \sum_{n=1}^{N} \frac{1}{x_{nk}} \end{gathered} \tag{4-36}$$

$$\begin{gathered} B''_{kn} = -B_{kn} = -\frac{x_{kn}}{r_{kn}^2 + x_{kn}^2} \\ B''_{kk} = \sum_{n=1}^{N} -B_{kn} \end{gathered} \tag{4-37}$$

Hence, B matrices in the FDLF method are smaller than those in N-R method and computationally simpler to solve. The FDLF algorithm is adopted by the IPSA+ package [178], the commercial power system analysis software used throughout this thesis. Many DNOs such as EDF and SP Manweb currently use IPSA+ as the major network analysis tool, which is one of the primary reasons that it is used for this research work.

4.1.4 Sensitivity Coefficients in Power Systems

Power system operation is characterised by sets of parameters, state variables and controllable variables [48]. The operating states of a power system depend on the parameters for system variables and control settings of variables. If the net power injected into all busbars are denoted as y, then the dependent variables y shall be a function of independent variables (or decision variables) x and control variables u, mathematically expressed as $y = f(x, u)$. To study how a change of one or more control variables will change the operating condition, linear sensitivity coefficients S_{xu} are generally determined using equation (4-38).

$$S_{xu} = \lim_{\Delta u \to 0} \frac{\Delta x}{\Delta u} \tag{4-38}$$

where Δx is a small change in decision variables and Δu is a small change in control variables.

In particular, linear sensitivity factors can be expressed as partial derivatives. Equation (4-39) shows the sensitivity of the state variable x with respect to a change at a control variable u [48].

$$S_{xu} = \frac{\partial x}{\partial u} \tag{4-39}$$

where S_{xu} are the first-order sensitivities of the state variables with respect to the control variables.

In power system analysis, decision variables x are voltage magnitudes and angles for PQ buses and voltage angles for PV buses; control variables u are controllable such as transformer tap positions, generator MW output and generator terminal voltages; the function $f(x, u)$ is dependent on the x and u variables [48].

$$x = \begin{bmatrix} \delta_2 \\ \vdots \\ \delta_n \\ V_2 \\ \vdots \\ V_n \end{bmatrix} \tag{4-40}$$

$$u = \begin{bmatrix} V_g \\ t_n \\ \vdots \end{bmatrix} \tag{4-41}$$

$$f(x,u) = \begin{bmatrix} P_{T2} - P_{G2} + P_{D2} \\ \vdots \\ P_{Tn} - P_{Gn} + P_{Dn} \\ Q_{T2} - Q_{G2} + Q_{D2} \\ \vdots \\ Q_{Tn} - Q_{Gn} + Q_{Dn} \end{bmatrix} \tag{4-42}$$

where δ_n and V_n are the phasor angle and magnitude of the voltage at busbar n, V_g is the voltage at the generator busbar g, and t_n is the tap position setting for transformer n; P_{Tn}, Q_{Tn}, P_{Gn}, Q_{Gn}, P_{Dn} and Q_{Dn} are the active and reactive power transmitted, generated and consumed respectively at busbar n.

In a balanced power system, the net power flowing through each node is zero, i.e. the different between power injection and absorption at a node is equivalent to the power transmitted through it, as shown in equation (4-43) and (4-44).

$$\sum P_k = P_{Gk} - P_{Dk} - P_{Tk} = 0 \tag{4-43}$$

$$\sum Q_k = Q_{Gk} - Q_{Dk} - Q_{Tk} = 0 \tag{4-44}$$

which is equivalent to the following equations expressing transmitted power though bus k:

$$P_{Tk} = P_{Gk} - P_{Dk} \tag{4-45}$$

$$Q_{Tk} = Q_{Gk} - Q_{Dk} \tag{4-46}$$

In AC power systems including tap-changing transformers and shunt devices, the active and reactive power flows through a busbar k can be calculated using equation (4-47) and (4-48), on the basis of equations (4-6) and (4-7).

$$P_{Tk}(V,\delta) = Re\left[\left(\sum_n V_k[(V_k - t_{kn}V_n)Y_{kn}]^*\right) + V_k\left(V_k \sum_k Y_{shuntk}\right)^*\right] \tag{4-47}$$

$$Q_{Tk}(V,\delta) = Im\left[\left(\sum_n V_k[(V_k - t_{kn}V_n)Y_{kn}]^*\right) + V_k\left(V_k \sum_k Y_{shuntk}\right)^*\right] \tag{4-48}$$

where t_{kn} is the transformer tap in branch connecting bus *k* and *n*,

Y_{kn} is the branch admittance between bus *k* and *n*,

Y_{shuntk} is the sum of the branch and bus shunt admittances at bus *k*

Changes in active and reactive power at busbar *k* dependent on voltage magnitudes, voltage angles and tap positions are calculated as follows [48]:

$$\Delta P_k = \sum \frac{\partial P_k}{\partial V_n} \Delta V_n + \sum \frac{\partial P_k}{\partial \delta_n} \Delta \delta_n + \sum \frac{\partial P_k}{\partial t_{kn}} \Delta t_{kn} \tag{4-49}$$

$$\Delta Q_k = \sum \frac{\partial Q_k}{\partial V_n} \Delta V_n + \sum \frac{\partial Q_k}{\partial \delta_n} \Delta \delta_n + \sum \frac{\partial Q_k}{\partial t_{kn}} \Delta t_{kn} \tag{4-50}$$

The above equations can be rearranged in a matrix form to represent the relationship between the state variables and the control variables:

$$\begin{bmatrix} \frac{\partial P_k}{\partial V_n} & \frac{\partial P_k}{\partial \delta_n} & \cdots \\ \frac{\partial Q_k}{\partial V_n} & \frac{\partial Q_k}{\partial \delta_n} & \cdots \\ \vdots & \vdots & \ddots \end{bmatrix} \begin{bmatrix} \Delta V_k \\ \Delta \delta_n \\ \vdots \end{bmatrix} = \begin{bmatrix} -\frac{\partial P_k}{\partial t_{kn}} & 1 & 0 \\ -\frac{\partial Q_k}{\partial t_{kn}} & 0 & 1 \end{bmatrix} \begin{bmatrix} \Delta t_{kn} \\ \Delta P_k \\ \Delta Q_k \end{bmatrix} \tag{4-51}$$

Equation (4-51) is a linerasation of power flow equations at a certain solution point, with second and higher order components ignored. A more compact form of the matrix in terms of decision variables x and control variables u is:

$$[J_x]\Delta x = [J_u]\Delta u \tag{4-52}$$

where J_x and J_u refer to the Jacobian matrices relating decision variables and control variables.

Therefore, the relationship between decision variables and control variables can be calculated by rearranging the above equation:

$$\frac{\Delta x}{\Delta u} = \frac{[J_u]}{[J_x]} \tag{4-53}$$

The co-relation between control actions and their effects can be exploited using this sensitivity analysis technique. In non-linear systems such as power systems, the sensitivity factors relating the voltage control actions and reactive power scheduling can be studied through first order sensitivity function. Nonetheless, for a linear programming OPF approach, the convergence rate may be slow in some cases, hence second order sensitivities were used in [179] to overcome this limitation.

4.1.5 Voltage Sensitivities

As mentioned in section 3.2, voltages in power systems are subject to changes in active and reactive power injections on busbars as well as control actions such as step change in tapping positions of ULTC transformers or switching actions of MSCs. The sensitivities of voltage changes to such changes are explained in the following subsections.

4.1.5.1 Active and Reactive Power Sensitivities

In power flow analysis, variations in active and reactive power are computed based on Jacobian matrices and small perturbations of voltage magnitudes and angles, shown in equations (4-9) and (4-10) [48]. The applied Jacobian matrices can be inverted to calculate changes in voltage magnitudes and angles corresponding to changes in active and reactive power injection at busbars, shown in equation (4-54) and (4-55). The inverted matrices, also known as sensitivity matrices, reflect how sensitive voltages are to active and reactive powers.

$$\begin{bmatrix}\Delta P\\ \Delta Q\end{bmatrix} = \begin{bmatrix}J_{P\delta} & J_{PV}\\ J_{Q\delta} & J_{QV}\end{bmatrix}\begin{bmatrix}\Delta\delta\\ \Delta V\end{bmatrix} = \begin{bmatrix}\frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial V}\\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial V}\end{bmatrix}\begin{bmatrix}\Delta\delta\\ \Delta V\end{bmatrix} \tag{4-54}$$

$$\begin{bmatrix}\Delta \theta\\ \Delta V\end{bmatrix} = \begin{bmatrix}S_{\delta P} & S_{\delta Q}\\ S_{VP} & S_{VQ}\end{bmatrix}\begin{bmatrix}\Delta P\\ \Delta Q\end{bmatrix} = \begin{bmatrix}\frac{\partial \delta}{\partial P} & \frac{\partial \delta}{\partial Q}\\ \frac{\partial V}{\partial P} & \frac{\partial V}{\partial Q}\end{bmatrix}\begin{bmatrix}\Delta P\\ \Delta Q\end{bmatrix} \tag{4-55}$$

where $S_{\delta P}$, $S_{\delta Q}$, S_{VP} and S_{VQ} refer to the submatrices of the sensitivity matrix S, representing the partial derivatives of δ and V with respect to P and Q. To calculate voltages given sensitivity factors and changes in P and Q, the following equation is adopted.

$$V_{t+1} = V_t + \Delta V = V_t + S_{\mathrm{VP}}\Delta P + S_{\mathrm{VQ}}\Delta Q \tag{4-56}$$

where V_{t+1} and V_t are voltages at time $t+1$ and time t (‘time’ can also be interpreted as each iteration within a load flow calculation). Equation (4-56) can be used to calculate estimated voltages over a given time period where changes in P and Q are known.

4.1.5.2 Voltage Control Sensitivities

Starting from the FDLF assumptions shown in equations (4-29) or (4-35) as introduced in section 4.1.3 [180], [181], the Jacobian matrix is simplified and relation between reactive power and voltages can be represented in equation (4-57).

$$\Delta Q/V = B''\Delta V \tag{4-57}$$

where $-B''$ is the imaginary part of the network admittance matrix. The above equation can be expanded into equation (4-58) in terms of the two types of buses.

$$\begin{bmatrix} \Delta Q_c/V_c \\ \Delta Q_l/V_l \end{bmatrix} = \begin{bmatrix} B_{cc} & B_{cl} \\ B_{lc} & B_{ll} \end{bmatrix} \begin{bmatrix} \Delta V_c \\ \Delta V_l \end{bmatrix} \tag{4-58}$$

where subscript *c* denotes voltage controlled buses and *l* denotes load buses.

Transformer tap changer control

For an idealised transformer model shown in Figure 3-6, the equation (3-9) in the matrix form can be written as the following form:

$$\begin{aligned} I_p &= \frac{y}{t^2}V_p - \frac{y}{t}V_s \\ I_s &= -\frac{y}{t}V_p + yV_s \end{aligned} \tag{4-59}$$

Hence, the deviation in currents caused by tap changes can be derived by differentiating equation (4-59) into the following equations:

$$\begin{aligned} \frac{\Delta I_p}{\Delta t} &= -\frac{2y}{t^3}V_p + \frac{y}{t^2}V_s \\ \frac{\Delta I_s}{\Delta t} &= \frac{y}{t^2}V_p \end{aligned} \tag{4-60}$$

Assuming that the voltage deviation at voltage controlled busbar ΔV_c is equal to zero, from equation (4-58), the relation between load bus voltages and changes in reactive power can be obtained [182]:

$$\Delta V_l = B_{ll}^{-1}\,\Delta Q_l/V_l \tag{4-61}$$

Under the FDLF assumptions, the voltage magnitude is only related to reactive power, shown in equation (4-62).

$$\Delta Q_l = \begin{bmatrix} V_p \Delta I_p \\ V_s \Delta I_s \\ \vdots \\ 0 \end{bmatrix} \tag{4-62}$$

By substituting equation (4-62) into (4-61), the following equation relating the changes in load bus voltages and the changes in tap positions can be obtained:

$$\Delta V_l = B_{ll}^{-1} \begin{bmatrix} \Delta I_p \\ \Delta I_s \\ \vdots \\ 0 \end{bmatrix} \tag{4-63}$$

Equation (4-60) can be taken into the above equation to obtain the voltage control sensitivity matrix for a tap-changing transformer connecting bus p and s with a tap setting of t and magnitude of admittance y as below:

$$S_{vt} = \Delta V_l / \Delta t = B_{ll}^{-1} \begin{bmatrix} \dfrac{\Delta I_p}{\Delta t} \\ \dfrac{\Delta I_s}{\Delta t} \\ \vdots \\ 0 \end{bmatrix} = B_{ll}^{-1} \begin{bmatrix} V_p \dfrac{-2}{t^3} y + V_s \dfrac{1}{t^2} y \\ V_p \dfrac{1}{t^2} y \\ \vdots \\ 0 \end{bmatrix} \tag{4-64}$$

Shunt compensation

Sensitivity factors relating voltages and control actions of switching an MSC or shunt can be derived on the basis of (4-58) as follows. A change of reactive power at a load bus will change the reactive power flow from voltage controlled generators but not the voltage at the generators. Hence, equation (4-58) becomes:

$$\begin{bmatrix} \Delta Q_c / V_c \\ \Delta Q_l / V_l \end{bmatrix} = \begin{bmatrix} B_{cc} & B_{cl} \\ B_{lc} & B_{ll} \end{bmatrix} \begin{bmatrix} 0 \\ \Delta V_l \end{bmatrix} \tag{4-65}$$

The above equation can be expanded into the following form:

$$\begin{gathered} \Delta Q_c / V_c = B_{cl}\, \Delta V_l \\ \Delta Q_l / V_l = B_{ll}\, \Delta V_l \end{gathered} \tag{4-66}$$

Hence, the sensitivity matrix reflecting voltage change due to the change of reactive power compensated by an MSC or MSR can be derived by rearranging (4-66) as below:

$$S_{vm} = \Delta V_l / \Delta Q_l = B_{ll}^{-1} (Diag[V_l])^{-1} \tag{4-67}$$

Voltage changes at load buses because of the switching action of an MSC or MSR should be the multiplication of S_{vm} and the reactive power Q_m provided by the MSC or shunt, which is calculated using equation

$$Q_m = V_m I_m \sin(\varphi) = V_m^2\, Y_m = V_m^2\, B_m \tag{4-68}$$

where is the phasor difference between voltage V_m and current I_m.

Generator voltage control

A change at the terminal voltage of a generator will change voltages at load buses but not the reactive power of load buses. Hence equation (4-58) is turned into:

$$\begin{bmatrix} \Delta Q_c/V_c \\ 0 \end{bmatrix} = \begin{bmatrix} B_{cc} & B_{cl} \\ B_{lc} & B_{ll} \end{bmatrix} \begin{bmatrix} \Delta V_c \\ \Delta V_l \end{bmatrix} \tag{4-69}$$

The above equation can be expanded into the following form:

$$B_{lc} \Delta V_c + B_{ll} \Delta V_l = 0 \tag{4-70}$$

Equation (4-70) can be rearranged to derive the sensitivity of voltage at load buses caused by the change of voltage at the PV buses:

$$S_{vc} = \Delta V_l / \Delta V_c = -B_{ll}^{-1} B_{lc} \tag{4-71}$$

The voltage control sensitivity matrices introduced in equation (4-64), (4-67) and (4-71) are used the methodology proposed in this thesis for scheduling sequences of actions; equation (4-56) is used to calculate time series voltage profiles based on demand and generation profiles.

4.2 Review of Voltage Control Methods in the Existing Literature

Publications concerning the RPD and voltage control problems primarily involve the determination of appropriate settings for various local voltage control equipment so that the voltages across the system as a whole remain within acceptable limits. The voltage control problem can be a complicated one considering those factors:

1. A change of one control action can result in voltage changes at several buses;
2. To relieve a voltage violation, one or several control actions may be applied;
3. The control action to be applied should not incur any further security risks;
4. The number of control operations should be minimised over time to reduce the wear-and-tear on the equipment.

On both transmission and distribution networks, equipment for control of voltages is generally designed to regulate at a particular location to a particular target which is determined by the operator. Without appropriate decision support and where the determination of targets is dependent on operator judgment, it is likely that control target setting will be sub-optimal or, worse, infeasible in terms of respect of voltage limits. As a result, modelling of operators' decision-making process has been of interest in the context of voltage control and RPD problems. A number of publications are concerned with identification of an optimal set of voltage targets or tap positions for tap-changing transformers and status settings or output for reactive compensation equipment.

As a branch of the OPF, RPD problems are typically treated as an optimisation problem that involve both continuous variables (e.g. reactive power output of generators), discrete variables (e.g. tap ratios of transformers), and nonlinear constraints (e.g. system voltage limits); it can be formulated as a mixed integer non-linear programming (MINLP) problem [183]. Hence, both conventional algorithmic optimisation techniques and recent population-based and heuristic optimisation techniques have been proposed to solve the problems. Other techniques include AI-oriented methods and physics-based methods etc. A good number of these methods are based on sensitivity analysis introduced in section 4.1.

Depending on the way of handling the RPD and voltage control problems, the existing publications are primarily concerned about two types of problem: the settings of control variables at a snap shot, i.e. in a real-time manner, and the settings of control variables for a specific time period given the knowledge of the time-varying system condition. For instance, short-term scheduling can look into the 24 hour time period day ahead to determine which control actions should be used for each hour [167]. To clearly categorise these methods, the terms "dispatch" and "scheduling" need to be distinguished, as illustrated in Figure 4-1: "dispatch" refers to the decisions regarding control variable settings at a specific point in time when the system condition is known and fixed, i.e. at a certain snap shot; "scheduling" is concerned with the hourly or half-hourly settings for control variables for a certain time period.

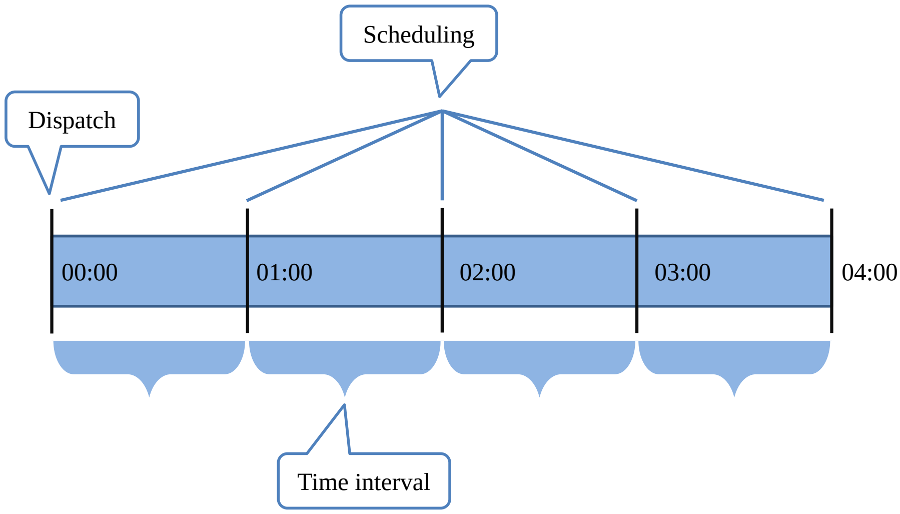


Figure 4-1 Illustration of the term "dispatch", "scheduling" and "time-interval"

In particular, out of the scheduling methods, some publications considered the changes in system conditions between adjacent time points, which are known as the "time-interval" based approaches. The significant dispatch and scheduling publications are reviewed in the first two subsections under different technique categories while the voltage control methods concerning time intervals are especially investigated in a separate subsection that also involved optimisation or AI-oriented techniques. It should be noted that the difference between scheduling and planning is that planning looks into a longer time period than scheduling problems. The difference between RPP and RPD is introduced in section 3.3.3.

4.2.1 Conventional Optimisation Methods

Dispatch of reactive power sources is one subset of the established OPF problem for determining voltage control variables, e.g. terminal voltage or reactive power output of generators, static reactive power compensators, tap ratios of transformers and status of shunt capacitors or reactors and so on [184]. The most common optimisation objectives are to minimise the total power losses or the control costs; the constraints normally involve power balance equations, voltage magnitudes of busbars, power flows along lines or cables and so on [185]. Major advantages of RPD or optimisation are summarised as follows:

- Reactive power sources are dispatched with efficiency to lower reactive power flows and to lessen active power losses in the power system;
- The decrease in reactive power flow in the system indicates improved power factor from the generator’s perspective and enhanced reliability from the system operator’s;
- The slopes of voltage are decreased and the voltage performance improved to a higher level ;
- More efficient use of existing equipment resulting in the deferment of capital investment with regard to new reactive power compensation;
- The primary benefit to the system operator lies in the decline of ‘out-of-merit’ operation.

The optimisation problem for RPD in a power system has the following characteristics:

- A large number of variables are usually involved in the power system optimisation model;
- There are equality constraints in terms of the power balance for all the busbars in the system;
- Some of the control variables are discrete, such as the tap ratios, status for reactive equipment; others are continuous, such as the output of reactive compensation devices and voltage magnitudes of busbars;
- The objective function may be non-linear and difficult to be solved under many constraints;
- RPD is usually treated independently from active power dispatch for simpler calculations.

In the mathematical model, the objective function to be minimised is normally expressed as the total active power losses in equation (4-72) or the total reactive costs in equation (4-73):

$$Min \sum P_{loss}^{km} \tag{4-72}$$

$$Min \sum_{\Delta u} C' \Delta u \tag{4-73}$$

where P_{loss}^{km} refers to the active power loss on each line or cable between busbar k and m; C' refers to the cost associated with changes in control variables; Δu refers to the change in control variables.

Constraints considered in RPD normally include power balance equations shown in (4-45) and (4-46) and inequality constraints on control variables x in (4-74) such as tap ratio and reactive power output of compensation devices and also on dependent variables y in (4-75) such as busbar voltages.

$$\Delta u^m \leq \Delta u \leq \Delta u^M \tag{4-74}$$

$$\Delta y^m \leq \Delta y \leq \Delta y^M \tag{4-75}$$

where P_{Gk}, P_{Dk} and P_{Tk} refer to the active power generation, active demand and active power transmitted to the grid at node k respectively; Q_{Gk}, Q_{Dk} and Q_{Tk} refer to the reactive power generation, reactive demand and reactive power transmitted to the grid at node k; Δu^m and Δu^M are the lower and upper limits of control variables.

In particular, sensitivity analysis, as described in section 4.1, is often found to be applied within the optimisation problem to linearise the nonlinear power flow problem. The sensitivity matrix representing the relationship between control variables and dependent variables is shown in equation (4-76):

$$\Delta y = S\,\Delta u \tag{4-76}$$

where the sensitivity matrix S should be comprised of submatrices relating each type of control variable to dependent variables such as busbar voltages shown in (4-77).

$$S = [S_{vg} \quad S_{vs} \quad S_{vt}] \tag{4-77}$$

where S_{vg}, S_{vs}, S_{vt} refer to the sensitivity matrix that relates changes in busbar voltages to generator voltage change, shunt capacitor/reactor status change and transformer tap ratio change.

Conventional optimisation techniques typically require successive linearisation with respect to decision variables and need to guide their search directions using first and second order differentiations of the objective function and constraints. The fundamental algorithmic optimisation techniques used for RPD are reviewed in [186]–[189]. Major techniques include linear programming (LP) method in [190]–[192], non-linear programming (NLP) method in [193][194], Newton method in [195], quadratic programming (QP) method in [196], interior point method (IPM) in [197], dynamic programming (DP) in [198] and [199] and particle swarm optimisation (PSO) method [200]. The advantages and disadvantages of these methods are summarised in Table 4-1.

Table 4-1 Conventional optimisation techniques used for RPD in OPF literature ([201][188][186][197][191][202])

Methods	***Features***	***Major advantages***	***Limitations***
LP (1988)	Often requires first order linear sensitivity coefficients	Reliable, good convergence, fast solution	Difficult to reach a solution for the non-linear RPD problem; requirement of an initial solved load flow case which to linearise from; local optimal solution rather than global optimum; solutions is dependent on the initial condition
NLP (1994)	Characterised by nonlinear objectives and/or nonlinear constraints	Capable of reaching for solutions for the non-linear RPD problem	Slow convergence rate; local optimal solution rather than global optimum; solutions is dependent on the initial condition; numerical difficulties or ill conditionings
IPM (1994)	Search solutions within the interior of a feasible space	Fewer number of iterations required, fast solution	Numerical difficulties or ill conditionings
Newton based (1995)	Requires calculation of second-order partial derivatives and iterative solution methods	Fast quadratic convergence properties; good robustness	Difficulties to process active set identification owing to lack of knowledge; may need a large number of trial iterations; singularity problems
DP (1995)	Decomposition of a complex problem into a sequence of sub-problems	Capability to deal with discrete variables, non-convex, non-continuous and non-differentiable functions	Not suitable for dispatching reactive power sources in a large scale power system since the solution space grows quickly as the size of system increases
QP (1997)	The objective function is quadratic and constraints are linear; requires calculation of second-order partial derivatives	Reactive costs can be modelled more accurately using quadratic functions	Generally requires a lot of computational effort to form the quadratic functions

Dynamic Programming

Dynamic programming is an optimisation method that solves a complex problem by turning it into a number of simpler problems. The essential characteristic of dynamic programming is its technique with a multistage nature, i.e. the method decomposes a multi-variable optimisation problem into a sequence of stages, with optimisation done with respect to one and only variable at each stage [189]. The problems that dynamic programming can cope with generally fall into the following categories: discrete problems, continuous problems, deterministic models and stochastic models. Dynamic programming treats an N-variable problem as a series of N single-variable problems that are solved by sequence. Generally, these N sub-problems are easier to solve than the original problem. The optimisation techniques that are used in different decomposed problems are irrelevant. Classical optimisation techniques can be directly applied to solve the multi-stage decision problems. This demands several requirements: the number of variables should be small; the functions should be continuous and continuously differentiable; the optimum points not being at the boundary.

The multistage feature of dynamic programming makes dynamic programming a useful technique for solving the unit commitment problem on the basis of a priority order for generators. Dynamic programming algorithm can solve the scheduling problem forward from the starting time slot or backward from the ending time slot [48]. The forward dynamic programming is more effective considering that it is easy to set initial conditions as starting point. In addition, the forward path is particularly advantageous when previous information of generating units is important for later calculations. In forward dynamic programming, two additional variables are defined in unit commitment problems for controlling computational effort: the number of states to search in each time slot X and the number of strategies (or paths) N. The number of units corresponds to the upper limit of X. By reducing N the number of strategies, the cheapest strategies are saved by eliminating the most expensive schedules in each time slot. However, the theoretical optimal schedule cannot be guaranteed under a reduced number of strategies and search states. Besides, for large-sized power systems, experimentations are necessary in each time slot for the solutions under a reduced number of combinations, which means heavy computational effort.

To sum up, the static optimisation techniques listed in Table 4-1 have been favoured for their robustness and reasonable mathematical arguments; they also can be used along with mathematical techniques such as sparsity techniques and Benders decomposition. However, most of these methods suffer from the following difficulties [185]:

- No guarantee of global optimum solutions
- Possibilities of non-convergence of the optimisation problem
- Heavy computation effort and unknown convergence rate (typically sensitivity to the size of the problem)
- Exposure to network uncertainties e.g. load fluctuations and renewable generation intermittency
- Requirement of continuous engineering judgement and experience over time in defining optimisation objectives, system constraints and the way to handle constraints in terms of prioritisation or relaxation

OPF programmes are usually expensive to be implemented and computationally intensive. Optimisation results tend to be quite complicated to for engineers interpret and its application in the distribution management systems is still under investigation [203] and [204]. In particular, most of optimal RPD publications deal with voltage control problem at snapshots unless optimisation is performed over the course of time. Examples are especially introduced in section 4.2.3.

4.2.2 AI-related Techniques and Other Methods

AI is a discipline that was formally put forward in 1956 and has been under development for years covering an extensive variety of fields including general-purpose problems such as data interpretation and specific tasks such as moving objects from one place to another [205]. Definitions of AI are not consistent in existing literatures and some principal examples are listed as below:

> "Artificial intelligence is the study of how to make computers do things at which, at the moment, people are better." (1991) [206]

> "Artificial intelligence (AI) may be defined as the branch of computer science that is concerned with the automation of intelligent behaviour." (1993) [207]

> "Artificial intelligence is the science of making intelligent machines that perform tasks as well as, or better and faster than, humans can. AI isn't really about intelligence, though. It's about solving problems. But the solutions in AI are always math-based and computer-based." (2010) [208]

Other definitions can be found in [205]. It has been pointed out that existing definitions of AI may be distinguished by the major dimension of focus: reasoning vs. behaviour in addition to human performance vs. intelligence [205]. The core of human-based methods is empirical science on the basis of hypothesis and validations while rationality-based methods normally concern mathematics and engineering. However, it is no coincidence that the various AI concepts are centred on "automation" and "intelligence". Some other terms have been proposed that represent the similar, if not the same, AI philosophies, such as computational intelligence and intelligent systems [209][210]. In particular, intelligence is about the capability to perform certain tasks, e.g. reasoning, learning, adapting and planning according to knowledge or logic [211]. Intelligence is typically indicated by the performance of a group of interactive individuals or agents (e.g. neural cells in neural networks). The performance of AI techniques needs to be compared with a human expert to verify its 'intelligence' [205].

The building of AI systems involves the following stages: defining a problem by at least specifying initial and expected final situations, analysing the problem by resorting to appropriate techniques, isolating and representing the task knowledge and eventually choosing the best technique for solving the particular problem and applying it. Knowledge representation and search are the major concerns in the AI field: knowledge representation involves the definition of problems in a programmable language manipulated via computers; search refers to the strategic navigation of fit solutions in a given space characterised by problem states [207].

Like most disciplines, the AI subject involves a certain range of problems and a set of techniques for solving these problems [206]. Since initiated, studies of AI have resulted in a good number of techniques such as knowledge based systems (e.g. rule-based systems and expert systems), model-based reasoning, case-based reasoning approach and statistics based (or data driven) methods (e.g. artificial neural networks (ANN), genetic algorithms (GA) and hidden Markov Models). The AI subject has a variety of subfields that are applied in different areas, e.g. machine learning, automated reasoning and theorem proving, natural language understanding and semantics [207]. Distributed AI is one of the prominent subset and mainly concerns the design and application of multi-agent systems (MAS) [212]. Swarm intelligence is also an AI discipline that looks into the design of MAS inspired by collective activities of social insects or other animal societies. A number of optimisation techniques have been developed under the swarm intelligence subject; the most prominently used ones are particle swarm optimisation (PSO) and ant colony optimisation (ACO) [213]. Both of these optimisation techniques have been proposed for scheduling generation in power system studies [214][215]. It is not the intention of this thesis to identify all the AI techniques and AI sub-disciplines but only those that are relevant to the power industry, and especially to RPD and voltage control problems (further discussed in 4.2.2).

One of the most notable developments in power systems since the mid-90s is the increasing popularity of AI techniques' application in power systems' operation, control and planning [185][216][217]. AI applications cover all areas of power system domain: analysis, planning, control and operation; the particular application of a certain technique depends on its inherent qualities and suitable problem domains [185]. Rule-based expert systems offer effective solutions to activities that demand unique responses from accurate reasonable analysis, e.g. substation switching and alarm handling. Fuzzy logic is widely applied to power system control designs. ANN systems are commonly used as an effective tool for predicting load due to its adaptive structure. GA systems often find applications in economic dispatch and unit commitment by virtue of its capability to handle integers and comprehensive representation of the power system problem. A common feature of all AI techniques mentioned here is their reliance on accurate descriptions of real-world problems and extensive domain knowledge [185]. Knowledge-based systems do not possess learning abilities or adaptability. ANN systems do not suffer from this limitation but depend on expert users in their design and interpretation and therefore fall short of reasonable modelling theories. Fuzzy systems also suffer from the lack of reasonable modelling background. GA systems are derived from robust mathematical models and are interpretable to engineers when implemented but GA is computationally expensive and the convergence properties still need to be addressed.

In addition to these methods, MAS and machine learning have also begun to gain growing interests since late 90s. MAS has been applied in the following areas in power system studies: power transformer condition monitoring [218], contingency constrained OPF [219], automation of power system substations [220], design of framework of an electricity market simulator [221], secondary or decentralised voltage control [222][223] and so on. Relevant technologies, standards and tools required for designing multi-agent systems are elaborately explained in [224]. Machine learning has been proposed for dynamic security assessment of power systems [225][226] and prediction of load, price and wind power [227].

Although AI methods have been very popular with researchers and a whole host of applications to power systems have been suggested since the 90s, but, as far as is evident from the literature, only a subset of the proposed methods have been adopted by the electricity industry. For instance, the multi-agent systems technology proposed by Davidson *et al* has been deployed by SP PowerSystems to automate the analysis and management of the monitoring data in power systems [228].

On grounds of the difficulties in applying the conventional algorithmic methods in the context of steady state voltage control and RPD, AI methods have been proposed and applied along with these methods since early 1980s [185]. The primary advantages of doing so are summarised as below:

- The uncertainties in network conditions can be better handled, e.g. using fuzzy rules in fuzzy logic systems;
- The decision-making process can be improved by introducing "intelligence" via learning capability and adaptability, e.g. the application of the ANN technique;
- The optimality search can be improved via appropriate guidance from initial conditions to better solutions, e.g. GA systems, ACO and PSO methods.

AI-oriented techniques that have been proposed by researchers for the benefit of voltage control or RPD include the following:

- Expert systems (1988 [229], 1997 [230])
- Fuzzy logic systems (1994 [231], 2003 [232])
- ANN (1994 [233])
- Genetic algorithms (1995[234], 1998[235])
- Evolutionary algorithms (1997 [236], 2005 [237])
- ANN and fuzzy hybrid systems (1998 [238])
- Particle swarm optimisation (PSO) algorithms (2001 [200])
- MAS-based approach (2001 [222], 2004 [239])
- Reinforcement learning approach (2004 [240])
- Ant colony optimisation (ACO) based approach (2005 [241], 2007 [242])
- Multiagent-based PSO approach (2005 [243])
- Quantum-inspired evolutionary algorithms (QEA) (2008 [244])
- Differential evolution algorithm (DEA) (2008 [245])
- Seeker optimisation algorithm (SOA) (2009 [246])
- Simulated annealing (2011 [247])
- Gravitational search algorithm (GSA) (2012 [248])

These methods can be differentiated depending on whether they are applied to solve RPD problems or short-term RPP problems, as shown in Table 4-2. It can be observed from the table that there have been relatively fewer publications on short-term RPP using AI-related methods.

Table 4-2 AI related methods categorised as RPD and short-term RPP problems

Methods	**RPD at snapshots**	**Short-term RPP**
Expert systems	[249] [250] [230] [229]	n/a
Fuzzy-control based	[184] [251] [252] [253]	[232]
ANN	n/a	[254] [255]
Evolutionary-based algorithm	[237]	n/a
Genetic algorithms	n/a	[256]
Hybrid systems of fuzzy systems and ANN	n/a	[238]
Reinforcement learning	[240]	n/a
MAS	[239]	[257]
Multi-agent based PSO	[243]	n/a
ACO	[242]	n/a
Differential evolution	[245]	n/a
QEA	[244]	n/a
SOA	[246]	n/a
Simulated annealing	n/a	[247]
GSA	[248]	n/a
Dead band control algorithm	n/a	[258]
A nonlinear IPM and discretization penalties based algorithm	n/a	[259]

The concepts of selected significant AI-oriented methods, their advantages and disadvantages regarding their application to power system voltage control are summarised in Table 4-3, followed by discussions on a selection of significant publications.

Table 4-3 AI-oriented methods used for voltage control in existing literatures ([185][260][261])

Methods	*Concepts*	*Advantages*	*Limitations*
Expert systems (1988)	A computer programme that carries certain expert characteristics, that is, the capability to solve problems using domain-confined knowledge [185] [260]	• Durability with respect of competency • Easy to be transferred, reproduced or documented • Capability to generate consistent results regardless of external conditions • Low operation costs • Quick response to emergent conditions • Modularity of rules	• Lack of adaptability to changing conditions • No creativity for solving problems • Data needs to be translated into symbols for expert systems with some information losses • Possibility of inappropriate knowledge representation • Difficulty in maintenance of large rule bases
Fuzzy logic systems (1994)	Fuzzy logic is a form of approximate reasoning. Fuzzy sets and rules, membership function and values and fuzzy logic controllers altogether constitute a fuzzy system [262]	• Easy to implement 'rule of thumb' experiences and heuristics • Clear symbolisation of natural facts • Flexibility to be tuned online or offline • Comprehensive mapping between input and output • Fast computation to solve for solutions • Computationally inexpensive	• Lack of adaptability to changing conditions • Difficulty in representing some knowledge in terms of fuzzy logic and rules • Difficulty in assessing the stability of fuzzy logic controllers
ANN (1994)	ANN analogues the humans' learning process and involves a large number of nonlinear elements (also known as neurons) that are interconnected via weighted links to obtain solutions for specific problems [99]	• Capability to perform fast non-linear computations – useful for real-time application • Practicality – easy to implement • Self-learning ability • Effective method for solving problems that have no direct algorithmic solutions but valid examples	• Inability to perform specific tasks • Requires sensible selection of learning examples • The quality of training results depends on a reasonable ANN architecture
Evolutionary algorithms (1997)	A subset of evolutionary computation, a generic population-based heuristic optimisation approach based on natural selections [236]	• Searches from a population of points instead of a single point • Search is guided directly by the objective function rather than derivatives	• Local optimal values rather than global optimum • Quality of search depends on proper settings of parameters • Premature convergence and local stagnation

GA (1998)	GA is based on population genetics and natural selections for searching optimisation solutions; each individual of a population within a GA indicates a solution to the posed problem [263]	• Capable of dealing with combinatorial nonlinear problems and non-convex and non-differentiable functions • Modularity – easy to implement and interface with other models • The level of difficulty for solving the algorithm will not increase as the number of constraints increase • Effective search technique on the basis of simple concepts	• No guarantee of global optimal solution within a limited time – inappropriate for real time applications • Requirement of large computational time
PSO (2001)	A population-based evolutionary technique motivated by the simulation of social behaviours (without selection of fittest particles) [264] [265]	• Quick convergence – no overlapping or mutation calculations • Capability to update particles in parallel • Does not require calculations of derivatives; • Does not rely on a good initial condition; • Performance not sensitive to the size and nonlinearity of the problem	• Lack of mathematical reasoning; • Incapability to reach a global optimal solution; • Requires tuning of parameters for different optimisation problems
ACO (2005)	Search algorithms stimulated by the foraging activities of ant colonies to solve discrete optimisation problems [266]; shortest path is found through graphs and communication mechanisms [242]	• Advantageous when the searching graph changes dynamically • Capability to be run continuously and adapted to changes • Good solutions can be found quickly through the feedback given by "simulated ants"	• Difficulty in theoretical analysis of the technique • The search and research is based on experiments instead of mathematical knowledge • Uncertain convergence rate
DEA (2008)	A greedy selection process on the basis of weighted differences between solution vectors [245]	• Capability to deal with mixed integer problems with nonlinear objectives and constraints	• The initial settings of control variables are randomly provided • Prone to premature convergence and stagnation • The position of the global optimum value is sensitive to the initial settings of control variables
SOA (2009)	A heuristic search algorithm inspired by the act of human searching that looks for the optimal solution by a seeker population [246]	• Simple to comprehend for engineers • Easy to implement	• Need to apply fuzzy reasoning to generate step length • For each seeker, a search direction and a step length need to be calculated at each iteration, hence it is computationally intensive

Expert systems

Some work intended to coordinate different control actions to maintain desired voltage profiles. For example, in [249], a rule-based expert system that combines integer linear programming and operators' dispatching rules was developed to control voltages. In [250], an expert system was designed to facilitate power system decision-making for reactive power and voltage control problems. Authors used empirical rules to determine control actions from generator voltages, transformer tap changers and shunt capacitors to keep voltages within required limits. In [230], authors suggested to apply steady-state network equivalents and an expert system to control voltage and reactive power in a large scale power system. Control actions were selected based on the interactions between power system sensitivity analysis and proposed expert systems. In [229], the sensitivity tree is proposed to form an expert system for real-time voltage and reactive power control. However, expert systems require a lot of computational effort to translate experts' knowledge and experience into clear rules and always need to adapt their knowledge base to each new case scenario.

Fuzzy control based methods

In [184], authors presented a fuzzy control based approach that involved translations from voltage variations and control variables into fuzzy set notations in order to control substation ULTC transformers to minimise voltage deviations. In [251], a coordinated control method for voltage and reactive power was developed on the basis of heuristic modelling and approximate reasoning where control heuristics were expressed as fuzzy rules. Linear equations along with control rules were used to obtain control models. In [252], authors suggested a fuzzy logic based dynamic boundary voltage and reactive power integrated control approach. Nevertheless, prior knowledge is needed and it is hard to estimate membership functions for fuzzy logic control. In [253], the standard decoupled approach was developed to enable appropriate selections of corrective actions to avoid undesired voltage violations, by embedding the new formulation of sensitivity analysis in a qualitative reasoning based decision support tool for network operators. A number of factors regarding available control actions were taken into account in the design of the tool: control costs, control effects and control margins, so that the control priorities can be altered when appropriate and dispatch results can be achieved quickly. In [232], a fuzzy-based reactive power and voltage control method was proposed to find the combination of ULTC positions and capacitors on/off status in a day so that voltage profiles could be kept in the appropriate limits and reactive power flow through the transformer and active power losses at feeders minimised. Nonetheless, fuzzy control based systems require prior knowledge and experience to be translated into fuzzy rules and it is difficult to assess the stability of fuzzy logic controls used in voltage control context.

Artificial neural network

In 1995, an AI approach based on the ANN technique was proposed in [254] to optimally control reactive power with reactive load uncertainties incorporated. In 2005, a coordination control scheme based on ANN for an ULTC transformer and a STATCOM was presented in [255]. The objective was to minimise both tap changes of the transformer and STATCOM output while keeping voltage profiles within the required limits. An iterative condensed nearest neighbour rule was developed to train the competitive ANN. The ANN based coordinating controller took the known load trend into account but required prior analysis to derive suitable settings for control parameters, which is dependent on the topology of the system as well as the operators' knowledge and preferences. Besides, this ANN controller only considered the substation voltage rather than the voltages at the end of distribution feeders.

Evolutionary-based algorithms

In [237], authors presented a multi-objective evolutionary algorithm to solve the RPD problem where Strength Pareto Evolutionary Algorithm was used to solve the nonlinear constrained optimisation problem. The objectives included the minimisations of active power losses and voltage deviations. Three phases were involved: determination of the Pareto optimal set using a hierarchical clustering technique, the Pareto optimisation process and the use of fuzzy set theory for obtaining the fittest solution over the trade-off curve. However, this method is computationally expensive and the speed of calculation is quite slow.

Genetic algorithms

In [256], a genetic algorithm based method was presented to control voltage and reactive power in distribution systems under uncertain data environment. Non-statistical uncertainties in network conditions were introduced in a nonlinear fuzzy distribution power flow. The objective is to minimise the active power loss at the system boundary by finding crisp and best fit optimal solutions to control voltage in distribution systems. This method considers uncertainties in load forecasts but the optimisation process is costly and the computation speed is slow. Accuracy trade-off issues are yet to be investigated.

Hybrid systems of fuzzy systems and ANN

In [238], an ANN system was designed to determine capacitors status and ULTC positions for day ahead. The ANN system provided a preliminary dispatch strategy which was then refined by fuzzy dynamic programming to obtain the realistically appropriate schedule. However, this work only took into account the substation voltages rather than the voltage experienced by customers at the end of distribution feeders. Furthermore, the ANN technique usually requires an appropriate selection of system quantities at the training stage for complicated network models. More importantly, the precision of the recommendation given by an ANN is dependent on the coverage of the problem space in the training process [267]. For nonlinear voltage control problems in power systems, the use of ANN for extrapolation in voltage control problems is considered to be inappropriate and requires the application of other robust techniques.

Reinforcement learning

In 2004, authors in [240] proposed the use of reinforcement learning for solving RPD problems. Reinforcement learning is a type of machine learning techniques and is derived from optimal control theory and dynamic programming; it searches for optimal values iteratively on the basis of a mapping between states and control actions. In this work, the constrained load flow problem was firstly formulated as a multistage decision problem, then a model-free learning algorithm (referred to as Q-learning), a type of reinforcement learning algorithms, was used to learn a mapping from power system states and actions to an optimal value function that quantified the long-term value of taking certain actions. The Q-learning algorithm offered the flexibility in the choice of control actions via priorities; it was proved to be computationally faster than the GA because of the use of experience as guidance for iterative searches. However, this technique requires large storage space and the convergence rate is sensitive to the number of control actions.

Multi-agent system technologies

In 2004, authors in [239] proposed a coordinative optimisation approach on the basis of the MAS technology to better search global optimums. This approach decomposed the RPD system into several interactive subsystems and each local optimisation problem was distributed to an autonomous agent (or problem solvers). Each agent processed the local dispatch problem simultaneously under a layer control structure and then global dispatch problem is solved with the generation of approximate solutions under a network control structure. The authors claimed that, by using the MAS technology, the proposed approach helped the optimisation problem to reach a global optimum value efficiently.

In 2007, an autonomous decentralised voltage control method was developed in [257] to save excessive reactive power output. Power factor control of DGs and multi-agent technology were used and differential-difference type equations were formulated. Hunting phenomenon due to the time-delay was observed in [257]; hence [268] improved the control mechanisms by avoiding switching operations and using differential-difference equations on the basis of a superposition principle.

Although the MAS technology is gaining increasing attention these days, it lacks mathematical reasoning and serves more like a software platform and therefore requires the use of other mature techniques to achieve desired objectives. Furthermore, the implementation of the MAS technology normally requires communication links and a standard agent communication language to allow agents to interact. The practical implementation of the system is highly complex and may be difficult to administer [269].

Multi-agent based PSO

In 2005, an MAS-based PSO method was proposed in [243] to solve the RPD problem, where an agent represented a particle and potential solution to the optimisation problem. The method optimised the objective function through the interactions amongst agents and the evolution mechanism of the PSO algorithm: each agent can contribute information to the global space and share the information after diffusion. This approach appeared to be capable of converging to high-quality optimal solutions at a faster pace than the PSO algorithm or standard GA. However, this method is expensive to implement and although faster, it only looks into a snapshot of power systems and hence would take a rather long time to apply this approach to operational day-ahead planning studies.

Ant colony optimisation

In 2007, an ACO-based approach was proposed for solving the RPD problem and four types of ACO algorithms were applied in [242]. The approach involved the mapping of the solution space onto a search graph defined by a start node, a target node and all the arcs, where each stage represented a control variable and the states of a stage represented all possible settings of the corresponding variables. The "simulated ants" looked for the best route between the start node and the target node by choosing the appropriate next node to visit, depending on the amount of pheromone trail and some heuristic information.[17] The searching iteration was completed after all ants achieved a tour and the pheromones needed to be updated in each iteration of the algorithm. This approach required iterative running of the AC load flow to derive the value of the objective function for each ant. The proposed algorithm is computationally intensive and the convergence rate is rather uncertain.

Differential evolution algorithms

In 2008, a differential evolution approach was presented in [245] for solving RPD problems involving both discrete and continuous variables. The approach aimed at minimising active power losses in transmission systems by determining the optimal settings of control variables. This method dealt with the inequality constraints through a "penalty parameterless" approach in order to avoid the time-consuming trial and error process for deciding the penalty parameter. However, the method still requires trial and error test on the initial size of the population, which is highly relevant to the convergence speed, i.e. the optimisation process is highly sensitive to the population size. For a power system under varying conditions, the use of this method would not be appropriate.

Quantum-inspired evolutionary algorithm

In 2008, an evolutionary algorithm based on quantum computation was proposed for solving bid-based optimal active and reactive power dispatch in [244]. This approach aimed at determining the optimal settings of control variables for the dispatch problem taking into account the bid-offered cost. The dispatch problem was firstly formulated as an objective function, the minimisation of the total offered bid cost, under a number of system constraints. Then the QEA technique was adopted to solve for solutions on the basis of Q-bit individuals (indicating a linear superposition of single states) with the involvement of quantum collapse (for reducing the

[17] Pheromone is a chemical substance that ants lay on the ground while walking to guide others towards a target point. The more quantity of pheromone trail, the more ants attracted. The pheromone evaporates over time and loses quantity if no more pheromone was deposited.

computation effort in a classical computer instead of a quantum computer). The QEA technique also needed the prior knowledge of the bid curves of generators and involved a general quantum rotating gate helping to progress the quantum population. This approach is difficult to interpret and highly costly to implement and is inappropriate to use in operational planning by DNOs who typically do not have access to bid prices.

Seeker optimisation algorithm

In 2009, an SOA approach, inspired by the act of human searching, was presented in [246] to dispatch reactive power. The SOA approach was operated based on the search population where each individual was known as a seeker and the population needed to be divided into subpopulations. This approach was favoured by the authors for its simple implementation and easy interpretation, but it is rather computationally intensive due to the iterative calculations of a search direction and a step length for each seeker.

Simulated annealing

In 2011, a fuzzy simulated annealing approach was proposed in [247] to dispatch capacitors and transformer tap changers for 24 hours day ahead. The proposed approach involved a multi-objective fuzzy representation of the dispatch problem: voltage deviation minimisation, loss reduction and minimised number of operations of capacitors and tap changers. A goal-attainment procedure was adopted to transfer the multi-objective problem into a single objective one and to achieve a sound compromise between conflicting constraints, before simulated annealing was used to search for the optimum value. The authors claimed that the simulated annealing algorithm is easy to implement and capable of escaping the local optimums, but the convergence rate is rather slow with a zigzag search path. Besides, this approach may be rather costly to be implemented.

Gravitational search algorithm

In 2012, the gravitational search algorithm (GSA) was proposed to solve RPD problems in [248]. GSA is a heuristic search algorithm originated from the gravitational law and the law of motion and uses a gravitational constant to adapt the accuracy of the search; GSA assumes that objects with heavier masses have higher fitness values and lower velocity and attracts other objects via the gravity force. The proposed method initially set up the optimisation problem by formulating the objective function and constraints, then applied GSA by introducing gravitational and inertia masses to all objects via the gravitational constant and the best solutions, indicated by the positions of objects at certain dimensions, were found via iterative calculations of best and worst fitnesses, masses and velocity until a stopping criteria was satisfied. The use of GSA for RPD is fairly recent and appeared to be faster than the PSO algorithm, but GSA normally need a large number of iterations to reach an appropriate solution and also require rather large computer storage space because of the iterative calculation of a number of variables for each object (control variable), e.g. the gravitational constant, masses, positions of objects, velocity and acceleration.

Dead band control algorithms

In [258], authors proposed dead band control algorithms to diminish tap changer movements for 24 hours ahead of time . A performance index related to tap positions was introduced and load diversities were considered in the proposed algorithms. However, only one substation transformer was considered regardless of reactive compensation devices in this work.

Improved conventional optimisation technique

In 2009, the reactive power and voltage control problem was formulated as an MINLP problem in [259] and solved using a nonlinear IPM and discretization penalties. The maximum allowable daily switching operation number (MADSON) was respected in the algorithm and slack variables were introduced to convert inequality constraints to equality constraints. The application of the IPM involved the use of a Lagrangian function as well as the Karush-Kuhn-Tucker (KKT) conditions, i.e. the calculation of derivatives of constraints. This method is rather computationally intensive and the convergence rate is highly sensitive to the setting of the MADSON.

4.2.3 Methods Concerning Time Intervals

The previous two sections have introduced the techniques that approached the RPD and voltage control problems from a real-time point of view, or at snap shots. As for these that were concerned about the day-ahead scheduling of control variables, the changes in network conditions (e.g. loads and generation) were not considered but only the conditions at specific time points. This section particularly discusses the papers that were concerned about the time-varying nature of network conditions, especially the changes of load over time.

In 1985, capacitor and voltage regulator problems were treated as two independent optimisation problems under changing loading conditions in [270] with the same objective of minimising the peak power and power losses while satisfying voltage constraints. Although the varying nature of demand was considered in the form of load duration curve, the parallel optimisation algorithms take a long time and much space to solve for a system with many loads and distributed generation. In addition, it cannot be guaranteed that the optimisation problems will be convergent and produce optimal solutions. Hence this method may not be practically applicable.

In 1994, a fuzzy inference method was used in [231] to design a new voltage control equipment, where fuzzy rules were used to break down one day into five periods. Control sensitivities derived from mean voltage errors and time scheduled fuzzy rules were used to determine the timings of tap changing operations in a substation. However, due to the stochastic nature of demand and DGs in distribution networks, it can be a rather algorithmically complex task to divide a day into felicitous periods.

In 1995, on account of load trend over time, an integral tool involving numerical and heuristic methods are proposed in [271] to find a set of control variables so as to either alleviate voltage violations when there was more than one violation or to minimise power losses when there was no violation, depending on the state estimation results. Sensitivities, voltage bounds, reserve margins, along with load trend which is classified as increasing, decreasing, stable with reserves and clearly stable, were considered by an expert system for selecting corrective actions for alleviating violations. This tool applied a coordinate-descent gradient technique for solving the loss minimisation problem with a quick response. Although this tool was implemented by two utilities, it still relies on prior engineering knowledge and the operator's rules need to be modified to adapt to changing network conditions, e.g. outages of network components, changes in generation patterns or reinforcement of the network. Besides, as control variables and the number of rules increase, the process will become very slow.

In 1995, a three level (primary, secondary and tertiary) hierarchical control of voltage and reactive power was presented in [272] for short (one day) and very short term scheduling (15-30mins). To coordinate the online voltage control and the off-line scheduling process, a two-stage approach was involved in the control strategy: the short term reactive scheduling programme was executed at the first stage based on hydro-thermal scheduling and demand forecast one day in advance; then the very short term rescheduling programme was executed in an on-line study at the second stage on the basis of the actual operating point to minimise the voltage deviations of key nodes from 15 minutes to several hours in advance. In particular, the optimal voltage targets for the key buses were produced by the scheduling procedure for the most indicative time intervals of the daily load pattern. Hence, the robustness of this scheduling procedure is highly sensitive to the selection of time intervals. Also, this control strategy is costly to be implemented and strongly relies on real-time communication amongst control centres throughout a power system.

In 2002, authors approached the voltage control problem from an operational scheduling viewpoint by providing a "transition-optimised" solution in [273]. This work regarded the nonlinear problem as a time-based scheduling problem and aimed at reducing redundant control changes in the status and output of reactive compensation equipment from a time-domain aspect, instead of a static snap-shot perspective. An algorithmic technique was developed by modelling a multi-objective function including the minimisation of the active loss and the maximisation of the voltage collapse proximity indicator on the basis of the changes in control variables at time intervals. This technique also involved transition constraints on control variables so that these variables could be incrementally updated as the algorithm proceeded across all the time intervals. The sparse LP algorithm was used to optimise the linearisation problem. This approach is not suitable for discrete variables (such as transformer tap changer settings) because control variables were modelled as continuous variables in the LP problem [274]. Hence it cannot deal with switching status of equipment or the discrete tap position step changes. Besides, the robustness and efficiency of the approach is still to be verified. Nonetheless, further to this work, the discrete shunt devices for optimal reactive power flow problems are appropriately modelled in [275] where a novel method based on probabilistic and adaptive threshold approaches was proposed to reduce system losses.

In 2002, a heuristic and algorithmic integrated method was applied for reactive power optimisation in [276], where the varying nature of load was also taken into consideration. The objective was to decide appropriate control settings for capacitor banks and transformer tap positions day ahead with the daily demand curve segmented into 24 parts. The method required control variables to be simplified for the reactive power optimisation problem with constraints on the maximum allowable number of operations. The disadvantage of this method is that the optimisation problem needs to be computed for each hour and hence asks for a large solution space and long processing time. Moreover, whether the optimality of solutions is degraded due to the simplification of control variables is yet to be verified.

In 2002, a time-interval based control strategy was introduced in [277] to determine optimal day-ahead schedule for ULTC tap changer positions and capacitor status to reduce active power losses while respecting the maximum allowance of the number of operations for the ULTC and the capacitor. This time-interval based approach reckoned that several load levels could be found in a daily load pattern and no control actions might be required when the loading condition was within each load level. Hence, the GA technique was used to divide a daily load forecast into several sequential levels and identify appropriate load levels by determining the start and end times for each level. To achieve desired scheduling results regarding the transformer and the capacitor settings, the GA was based on a tournament selection model for choosing the parents to crossover. This method does not require as much space as conventional optimisation methods but the partitioning of load require engineering judgement for choosing a specific number of load levels and the changes in control variables between two adjacent load levels may be fairly large. This approach can become computationally complex for steep and diversified demand curves. The partitioning method will need to be revised if DGs are present in the network.

In 2003, a time-interval based control strategy was introduced in [278] to determine optimal schedule for ULTC settings and capacitor switching to reduce losses and ensure the number of operations lower than the maximum allowance. A generic algorithm was used for load level partitioning and dispatch scheduling. This method does not require as much space as conventional optimisation methods but the partitioning of load can become computationally complex for steep and diversified demand curves.

In 2010, a hybrid method based on the ANN and the ACO techniques for minimising the active power losses at the current time interval whilst maintaining voltage security was presented in [279]. The ANN was trained using real-time measurements and offline simulation results to estimate the voltage stability margin, which was then used as one of the constraints for the optimal RPD problem solved by the ACO technique. The given daily active and reactive load profiles were evenly divided every 15 minute and the ACO was used at every operating time interval. This approach involves heavy computational effort in the training of ANN and the training process will be difficult if the system undergoes any topology changes. This hybrid model is quite computationally intensive due to iterative use of the ACO and the convergence rate is unknown.

In 2012, automated voltage control schemes in an area with wind farm connections were considered at three hierarchies in [280]: system control, wind farm control and equipment control. In particular, a two-tier and multi-stage control strategy was proposed for the control of a wind farm. The first tier provided control strategies for discrete reactive control equipment with the objectives being the minimisation of voltage deviations and the number of switching operations during one time interval (one hour) based on very short term wind power forecasting. The second tier then divided the time duration of the first tier into a number of stages (15 minutes) and provided strategies to continuous reactive equipment of each stage with objectives of minimising voltage deviations and maximising the voltage stability margin. A fast and elitist multi-objective genetic algorithm known as Non-dominance Sorting Genetic Algorithm (NSGA)-II was used to solve the multi-objective optimisation problems. Limitations of the proposed control strategy are that it requires iterative execution of load flow algorithms to obtain the static voltage stability margin and that the application of NSGA-II is highly costly and computationally intense.

4.3 Summary

The chapter has included a description of sensitivity analysis which is often used in voltage control studies. State-of-the-art voltage control methodologies in existing literatures have been reviewed thoroughly and commented in terms of their advantages and limitations. Although the RPD problem has been extensively dealt with in OPF literatures, it is still under investigation whether OPF programmes will be implemented in distribution networks.

It has been highlighted in this chapter that, although there have been a good number of papers concerned with voltage control problems, most of them only examine the problem either in a real-time perspective or at snap shots. As for those that looked into the problem from a time-interval based perspective, the complicated mathematical representation of the voltage control problem means that it is difficult to solve for a converged solution and the calculation is highly computationally intense.

5. Proposed Methodology

This chapter describes how the proposed methodology has developed from the initial research idea to achieve stated objectives by introducing the key components in the methodology and the way different parts of the methodology interact with each other. Advantages and limitations of the methodology are also discussed in this chapter.

5.1 The Role of the Methodology in the Operation of Distribution Networks

The primary objective of this thesis is to propose and validate a control methodology for managing voltages in a distribution network where DGs and loads have a time-varying nature, by scheduling voltage control equipment, such as ULTC transformers and MSCs, across an operational planning time period. In particular, when to apply a control action and which equipment to operate should be determined based on their effect on network voltages and associated control costs; the most control-effective and cost-effective actions should be scheduled at the appropriate time slots.

To ensure that voltage profiles in a distribution network do not fall outside required tolerance limits with varying loading conditions and generation levels, control engineers are required to make effective decisions on which control actions to take and at what time. The equipment used at a distribution substation for this purpose generally includes ULTC transformers and, at some locations, MSCs. ULTC transformers regulate their secondary bus voltages directly using automatic voltage regulators (AVR) via tap changers and MSCs in a substation are switched in or out so as to change the reactive power output from the substation and to regulate voltages at the substation and remote busbars [198]. In the UK distribution networks, ULTC transformers are the most widely used voltage control devices with AVC schemes that regulates the transformer tap changers according to given set points [39].

Practically in control rooms, these voltage targets or set points for transformers are set to be a fixed value until supply of electricity cannot be secured due to unforeseen conditions; control engineers then must adjust the set points or operate other devices based on past experience. Normally in the UK distribution networks, the voltage target for 33/11kV substation transformers is set to 11.1kV (1.01 per unit) at the primary side [52]. Due to the stochastic nature of DG and uncertainties in demand behaviours, there are risks that voltages might fall outside the required tolerance ranges. Furthermore, too frequent control actions will increase the wear-and-tear on the equipment and incur costs over time in that assets' maintenance intervals and life expectancy will be shortened. Hence, it is of vital importance for control engineers to effectively coordinate these control equipment in a reliable and economic manner. Cost-effective control actions need to be scheduled in order to improve network voltage profiles and maintain a satisfactory quality of power supply.

5.2 Key Components

In order to schedule control actions across a given time period, an AI planning approach is adopted in this work with the application of power system sensitivity analysis. Based on a given model of a practical distribution network, the intention is to use given demand and generation profiles from day-ahead forecasting results or historical data to estimate voltage profiles for a selection of nodes that are most likely to experience extreme voltages during a specific planning time period. The maximum and minimum voltage profiles experienced at each time slot, information of available control actions and associated voltage sensitivities are then given to an AI planner which has the capability to determine a sequence of settings for the control variables while respecting specified upper and lower voltage limits and to minimise the total number of control operations over the time span.

The proposed methodology involves an AI planning tool, power system analysis software and a programming language/platform that is capable of interfacing with both. The relationship between the power system sensitivity analysis and AI planning approach is shown in Figure 5-1. The ultimate objective is to obtain a sequence of control settings and voltage target settings using the AI planner on the basis of voltage profiles and sensitivity factors derived from power flow results and network calculations.

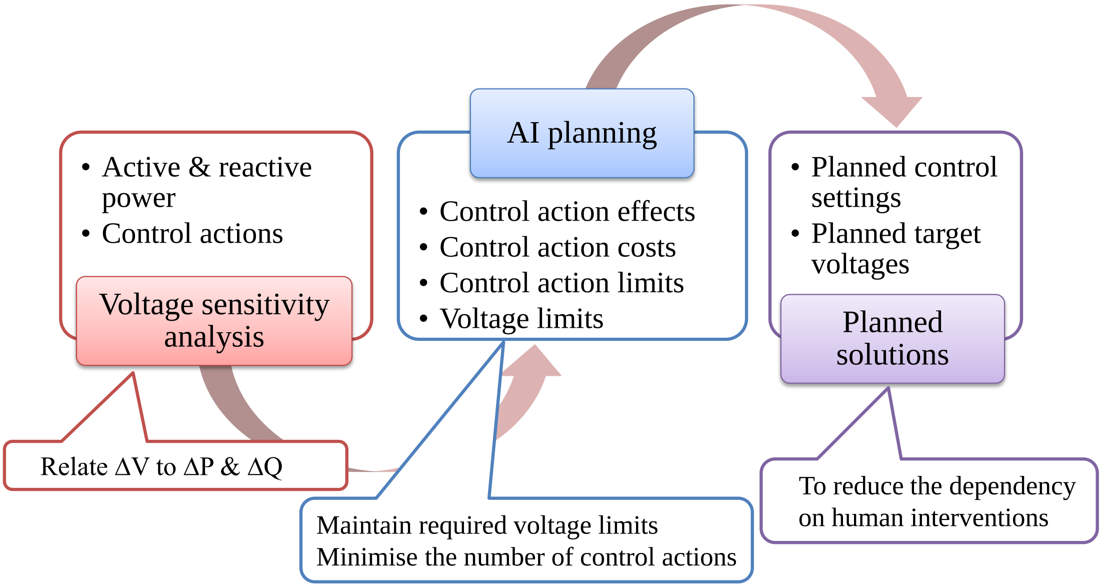


Figure 5-1 Components required for the proposed methodology

5.3 AI Planning

Planning is a branch of AI that specifically concerns the scheduling of a sequence of actions; this area of research has been active for about 50 years [281].

5.3.1 Definition

In simple terms, action planning refers to the capability of intelligent systems to schedule sequences of actions to fulfil certain purposes under given initial situations. The classical planning problem is defined as follows:

> "Given a description of the current situation (an *initial state*) of an agent, the means by which the agent can alter this situation (a set of *actions*) and a description of desirable situations (a *goal*), find a sequence of actions (a *plan*) that leads from the current situation to one which is desirable [282]."

AI planning has a philosophy of domain independence and uses a heuristic general search framework to solve a wide range of problems of different types. It is commonly used for action scheduling problems to specify what to do, when to do it and who does it. According to the definition of planning, it is necessary to specify the notions of initial states, actions and the ultimate goal for planning problems [282]. Take elevator control for example, initial states of the problem include the current location of the elevator as well as locations of passengers or objects ready to board; actions refer to the vertical movements of the elevator between different levels and passengers getting on board; the goal is to reach a particular floor.

It should be noted that the concept of 'planning' in the AI context is similar but not identical to 'planning' in the power system context. The concept of planning in the two domains is similar because both refer to a process of systematic decision-making. The difference is that AI planning is about scheduling a sequence of control actions to meet a certain goal whilst power system planning normally involves decisions on the vision for the future and tasks required to achieve certain objectives. However, AI planning techniques can be used to solve operational planning problems whose emphasis is on determining the best possible arrangement of the available resources to meet a set objective. The difference between operational planning and long-term planning is pointed out in section 2.2.

From the perspective of action scheduling, AI planning may appear to be similar to conventional optimisation problems such as unit commitment as descripted in [283]. Yet the key difference between them lies in that AI planning looks for a sequence of states that can meet a specific future goal while optimisation algorithms aim to find a set of values that can generate an optimum value for a specific objective function [281].

5.3.2 Planning Languages

Planning problems are generally computationally difficult even with the environment being observable and all actions being deterministic [282]. Significant effort has been made in investigating methods to solve 'typical' planning tasks. For example, the first International Planning Competition in late 1990s gave rise to a quasi-standard planning language that clearly defines the planning domain and relevant problems, known as the planning domain definition language (PDDL) [284]. Planning systems fundamentally involve general representations of states, actions, operators, goals and real-world models as well as fit-for-purpose searching techniques. AI planning has the capability to process problems from different domains and hence is regarded as a general-purpose problem solver [284].

Domain and problem

Specifically, the following components need to be specified in a PDDL planning task: objects, predicates, initial state of the objects, actions or operators and a particular goal. Two typical files are required to contain these components, a domain file for predicates and actions, and a problem file for objects, initial states and goal specifications. Generic templates of basic domain and problem files are given in Table 5-1.

Table 5-1 Generic templates of domain and problem files ([284])

Domain file	Problem file
(define (domain <domain name>) *(: requirements <r1>...<rn>)* *(: types <t1>...<tn>)* *(: constants <c1>...<cn>)* *(: predicates <p1>...<pn>)* *(: action 1 <a1>)* *...* *(: action n <an>)* *)*	*(define (problem < problem name>)* *(: domain <domain name>)* *(: objects ...)* *(: initial states* *(is1)* *...* *(isn))* *(: goal (...))* *...* *)*

Operators

A number of operators can also be specified in addition to action descriptions such as preconditions and action effects, shown in Table 5-2.

Table 5-2 Generic templates of preconditions and effects for PDDL domain files ([285])

Preconditions	Effects
and/or/not	*and/not*
exists <variable> <literal>	*forall <variable> <effect>*
forall <variable> <literal>	*when <variable> < effect >*
=/</ >/<=/>=	*increase/decrease/assign/scale-up/scale-down*

Quality of plan

PDDL has so far been through a number of versions with new features added with each version. For instance, a new field, *metric*, that measures the quality of plans, was appended on planning problem definitions to introduce optimisation objectives to be maximised or minimised, e.g. *(: metric minimise (function))* [285]. Discrete and continuous durative actions were also brought in the language so that the time duration that actions cause can be calculated and confined within a range. Action effects can be universally quantified (*forall…*) or conditional (*when…*). An example template of such actions is shown as below:

(:durative-action <name>
:parameters (<parameters>)
:duration (duration specification)
:condition (<preconditions>)
:effect (<effects>)
)

Constraints

Constraints can also be added to planning problems in terms of domain or problem files; constraint operators include: *always, sometime, within, at end, sometime-before, sometime-after, always-within, hold-during* and *hold-after* [285]. Examples are shown as follows:

(:constraints
(and (sometime (…))

```
            (sometime (…))
      )
  )
  (:constraints (and
      (forall (…)
       ((at end (forall (…)
            (and (…)))))
       ) )
  )
```

In this research work, the 2.1 version of PDDL [286] is used for the AI planning tool.

5.3.3 Planning Algorithms

To generate appropriate plans for AI planning problems, a number of planning algorithms have been developed and prominently used such as state-space search [281], partial-order planning[287], planning graph [288] and constraint satisfaction programming [289]. Search techniques in the area of AI planning are the subject of continuing research that focuses on ways of navigating the search space. While the details of the techniques are beyond the scope of this thesis, an overview of this area is presented here.

State-space search

State-space search is an approach that navigates planning solutions under given states, actions and associated preconditions and effects [205]. The state-space search is formulated on the basis of the following components: the initial states, applicable actions, goal tests and control step cost (typically 1). The search can start either from the initial states, namely forward search, or from the goal, namely backward search. The efficiency of forward and backward search is refined with the presence of a heuristic function that measures the approximate distance between a state and the goal [205].

Planning problems have also been solved using heuristic search [290]. Heuristic search planners use a general language STRIPS[18] to describe declarative problems and a general algorithm for extracting heuristics. The STRIPS language models a planning problem by a tuple P in equation (5-1)

$$P=<A, O, I, G> \tag{5-1}$$

where A represents a number of atoms (or individuals), O represents a number of operators, I represents the initial conditions of atoms and G represents the goal conditions of atoms. All the operators O are characterised by a precondition list $Prec(o)$, an add list $Add(o)$, and a delete list $Del(o)$.

Heuristic search planners automatically extract heuristics from STRIPS encodings and thereby convert planning problems into heuristic search problems [290]. Heuristics are normally used in search algorithms as guidance for the search and involve the state model S in equation (5-2) derived from the STRIPS problem P:

$$S_P = <S, s_o, S_G, A(s), f\,(a, s), c\,(a, s)> \tag{5-2}$$

where S is the set of atoms from A, initial conditions s_o are from I, goal states S_G specify all the goal conditions G, actions $A(s)$ refer to the operators O that satisfy relevant preconditions $Prec(a)$, a state transition function $f\,(a, s)$ that maps states s into states $s' = s — Del\,(a) + Add\,(a)$ for all the actions and action costs $c\,(a, s)$.

In heuristic planning problems, it is normally assumed that action preconditions are independent from each other to avoid unnecessary interrelations. The solution to this state space is a sequence of actions a_0, a_1 ... *and* a_n that corresponds to a state trajectory so that each action is achieved in each state each iteration and goal states to be realised at next iteration. The solution is assigned optimum values when the total cost is minimised.

The heuristic search is guided by a relaxed heuristic function h that is derived from a planning task where all delete lists $Del\,(a)$ of available actions are eliminated.

[18] STRIPS stands for Stanford Research Institute Problem Solver that was developed in early 1970s as an automated planner. The STRIPS language these days serves as a general base language for representing planning problems.

Heuristic functions can be defined on the basis of the planning purpose. For instance, the sum of costs of all atoms may be important in situations where each subgoal needs to be considered; the minimum value of the cost of all atoms is emphasised if an accurate estimate of the costs for a particular subgoal such as the most costly one is desired. For a set of atoms *A*: an additive heuristic function h_{add} in equation (5-3) that represents the sum of the costs of each atom in *A* and a max heuristic function h_{max} in equation (5-4) that selects the maximum cost out of all the costs. The additive heuristic h_{add} assumes that subgoals are independent and combines the costs of all the subgoals whereas the maximum heuristic only looks into the most expensive subgoals.

$$h_{add} = \sum_{a\ in\ A} g_s(a) \tag{5-3}$$

$$h_{max} = max\ g_s(a) \quad for\ a\ in\ A \tag{5-4}$$

where $g_s(a)$ is the cost of achieving each atom *a* in the given set *A* from the state *s*.

Solutions can be found by starting the search either from the initial states or from the planning goal, the former is known as forward planning and the later as backward planning [290]. Typical examples of forward state planning are hill-climbing planners and best-first search planners. The hill-climbing search iteratively selects one of the best solutions that minimises the objective function and expands it at every step until the goal is achieved. The best-first search maintains an open and closed tuple of nodes as actions and applies an evaluation function of plan associated costs with weighted nodes. Computational experiments have suggested that best-first search used in the simplest planner provides the most robust solutions over a wide range of problems, better and faster than the hill-climbing search.

While forward planning approaches require the heuristic to be calculated in each new state, backward planning does not rely on the re-computation of the heuristic of all the states [290]. Backward search is also known as regression search where states are regarded as sets of sub-goals and a set of atoms that represent a unique state in forward planning is considered to be a collection of states with all the inclusive atoms being true.

Normally two phases are included in regression search: a forward propagation for estimating action costs and the use of these costs for guiding the search. The goal states are regarded as a set of atoms that decide the root node for guiding the regression search. Regression search space refers to a tuple containing the available states, initial states, goal states, set of actions and state following the execution of actions and action costs. The solution to the regression space is the inverse of the solution to the progression search. In regression search, estimated costs obtained for all nodes from the initial condition are used to define the heuristic of all the states in backward search. The heuristic function *h* for a planning problem *P* is usually derived from a 'relaxed' problem *P'*. Due to its simple algorithms and relatively comprehensive analysis, heuristic planners are easy to be extended.

Although the regression planners generally solve planning problems faster than forward planners owing to reduced computation for heuristics, regression search in many cases results in questionable states that cannot be derived from the initial states and leads to useless search if not detected [290]. Forward planners do not suffer from this problem and make good use of the additional information generated when recalculating the atom costs in each state.

Whether planned solutions are searched in a forward manner or a backward manner, the heuristic function is obtained by ignoring delete lists which may result in the loss of some relevant properties. The general planner, METRIC-FF [291], can extend the process of "ignoring delete lists" to numerical state variables in order to maintain relevant properties of the problem relaxation for tackling linear tasks provided that the numeric task is monotonic. Therefore METRIC-FF requires that problems are expressed in terms of integer and linear variables [286]. METRIC-FF has been widely used and proved to be robust and quick [291]. Besides these advantageous features, it was used in this work because it can adequately express problems in terms of the language features that can interface with IPSA+ [178].

5.3.4 Applications

AI planning has been applied to many different fields such as robotics, process control, autonomous agents and spacecraft mission control in that these problems can be modelled using notations of initial states, actions and goals [282]. Since planning has been employed to various problem areas, it is often regarded as a general problem solving tool. In existing literatures, AI planning has been scarcely used in the context of power system management. Bell *et al* proposed the application of AI planning for power substation management in 2009 in order to reduce the wear-and-tear on substation equipment while maintaining the substation voltage within a satisfactory range [292]. The motivation for this application was that voltage targets have been conventionally determined by operators on the basis of engineering judgements which is a time-consuming and expensive manual process. AI planning therefore was used to design an automated system that can devise voltage targets for voltage control equipment such as transformers and MSCs. The work also took account of factors that could cause voltage changes at outgoing lines from the substation such as demand fluctuations, weather conditions, outages and maintenance activities. The objective was to minimise the number of control actions in between planning time slots and over the whole planning period while respecting defined voltage limits. Such actions include stepping up or down a transformer and switching in or out an MSC.

The innovative system was named Variable On-line Transformer Scheduling (VOLTS); the flowchart of VOLTS is depicted in Figure 5-2. METRIC-FF is employed in this work to express the decision making process and to find a suitable solution in a reasonable computational time. Discrete control actions and their effects are modelled in PDDL version 2.1. With a defined optimisation objective to achieve, METRIC-FF starts from an initial guess of solutions and iteratively appends constraints to former results before a plan that meets all constraints is achieved.

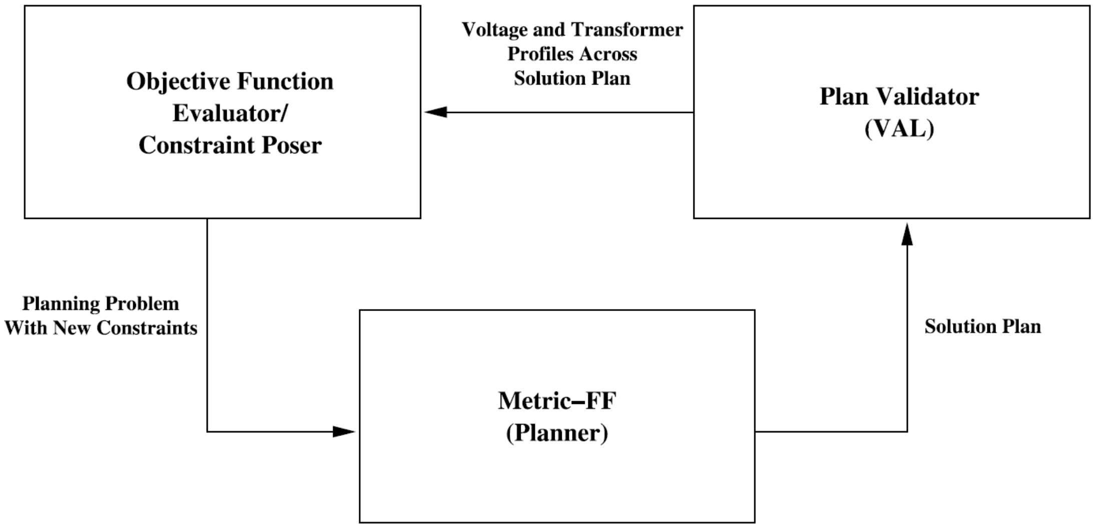


Figure 5-2 Flow diagram of the VOLTS system ([292])

However, the work is limited in the following respects [292]:

- Localised regulation: only the local voltage at the transmission substation was regulated by determining the control actions for the substation transformer and MSC, without considering the voltages at close-by network.
- Lack of mathematically sound reasoning: fixed sensitivity factors derived by intuitive engineering judgement were used, rather than mathematically calculated sensitivities.
- Lack of system validation: the planned results were not validated on any power system model.

The main innovations described in the present concern proposed methodology extensions to the mentioned existing work by overcoming its drawbacks in the context of distribution system voltage control.

5.4 The Role of AI Planning

The AI planning tool used previously for power substation management [292] is extended and developed in this work to interface with IPSA+ [178] to evaluate planned solutions; the shortfalls of the previous application were discussed in section

5.3.4. AI planning technique plays an important role in the proposed methodology and it uses a general search framework to solve the voltage control problem. The general forward search planner METRIC-FF was used in this work to represent the intelligent decision making process and to reduce the time it takes to compute solutions for complex problems. The advantages of using METRIC-FF were introduced in section 5.3.3.

In this thesis, the AI planning process involved in the voltage control scheduling process is illustrated in Figure 5-3, where the inputs, parameters and output of the AI planner are shown. The inputs are the description of the voltage control problem, i.e. the initial condition of the power system, the predicted time-series voltages for certain nodes, the voltage controllers' range of settings and control sensitivities as well as control costs. Based on these inputs along with given planning parameters such as the requisite voltage limits, the AI planner will schedule control actions, i.e. tap positions of ULTC transformers and switching status of MSCs, at the time slots where voltages fall beyond the limits so that voltage profiles throughout the planning time period will remain within the security constraints.

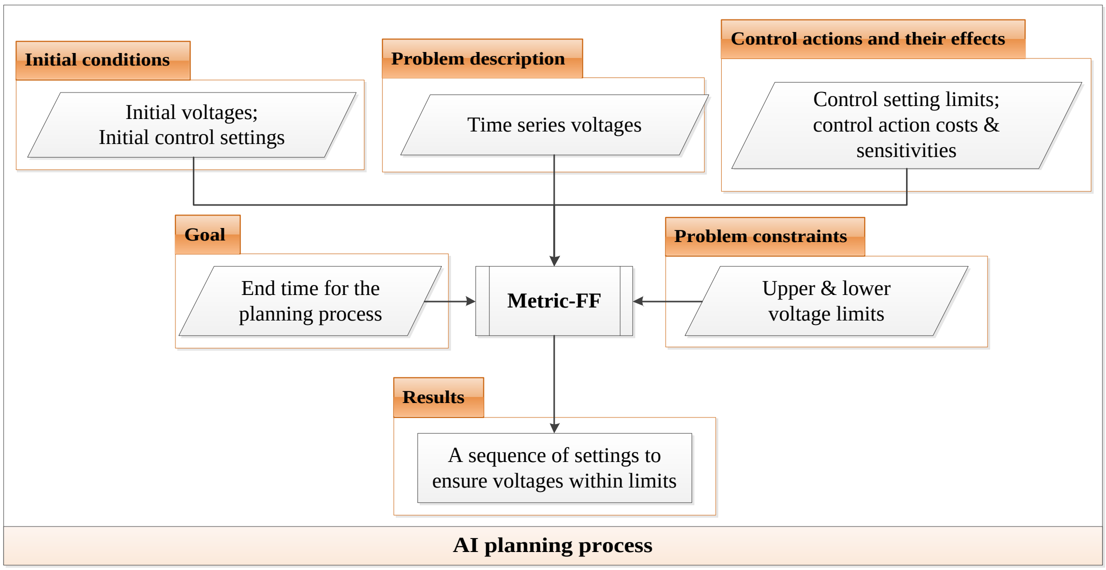


Figure 5-3 The AI planning approach used for voltage control problems

5.5 Power System Analysis Software

The power system analysis software allows electrical systems to be accurately modelled and its complex nonlinear nature to be studied under a wide range of scenarios. In the context of the proposed methodology, the functionality required of the load flow analysis software is listed below:

1. The capability to perform load flow calculations accurately and efficiently;
2. Easy access, import and export of network model parameters and calculated system states from load flow simulations, in a manageable format such as comma separated value (CSV) files;
3. Graphical user interface of network models including various voltage control equipment;
4. Capability to perform load flow analysis on network models using scripts/programming languages;
5. Preferably with existing applications by some DNOs in the UK or with a good potential to be applied by operators.

To the author's knowledge, power system analysis software that is used by the UK network operators and also available to researchers includes IPSA+, PSS/E and DIgSILENT PowerFactory software. Of the above software tools, IPSA+ [178] was chosen because it satisfies all the requirements listed above and most importantly its scripting language, Python, is able to interface with the proposed AI planner Metric-FF, as introduced in section 5.6. IPSA+ version 1.6.8 was used for the case studies presented in this thesis.

5.6 Scripting Programming

Python is an Object Oriented Programming (OOP) language that can run on a range of computing platforms including Windows and Linux and is free to use, easy to maintain and simple to interpret [293]. The language is extensible and has built-in modules for performing specific tasks, such as *math* for using mathematical operators, *numpy* for numerical calculations of matrices and arrays, and *matplotlib* for plotting graphs etc. Its extensibility means that one Python file can interface with another simply by calling its name, which supports the interface between IPSA+ and the AI planner.

Python also allows data stored in CSV files to be easily imported for manipulation and exported for other use. Python supports the use of classes as a standard feature of OOP; classes group functions together and deal with variables in a self-organised manner. A simple form of the class in Python includes the name of the class, initial definition of variables and definitions of functions, shown in the example below.

```
Class Name (object):
    def __init__ (self, initial variables):
        self.variable = initial variables
    def function (self, associated variables):
        function descriptions
```

5.7 Details of the Proposed Methodology

As mentioned before, to effectively schedule voltage control actions across a planning time period, the proposed methodology integrates power system sensitivity analysis as introduced in Section 4.1 and the AI planning approach in Section 5.3. Since the objective of this work is to plan out or schedule control actions for a specific period of time, the methodology takes historic or forecasted generation and demand profiles as input, under the assumption that given data is credible and accurate. In light of the typical cycle of demand, daily profiles are examined in this work, i.e. the planning time duration is 24 hours from midnight of one day to that of the next day. The time interval between planning steps is half an hour considering that electricity demand is quite often recorded on half-hourly basis [294] when monitoring devices or meters are available, and that load forecasts are typically hourly or half-hourly [295]. However, the length of the planning period and the planning time intervals are indefinite and depend on the nature of available demand and generation data. In the UK, demand and generation are forecasted every 30 minutes [296] and updated every 4 hours [34], in which case, the AI planner will be executed once in every 4 hours when the forecasted data become available and planned solutions will be provided for every 30 minute interval.

The proposed methodology is illustrated in the flowchart in Figure 5-4.

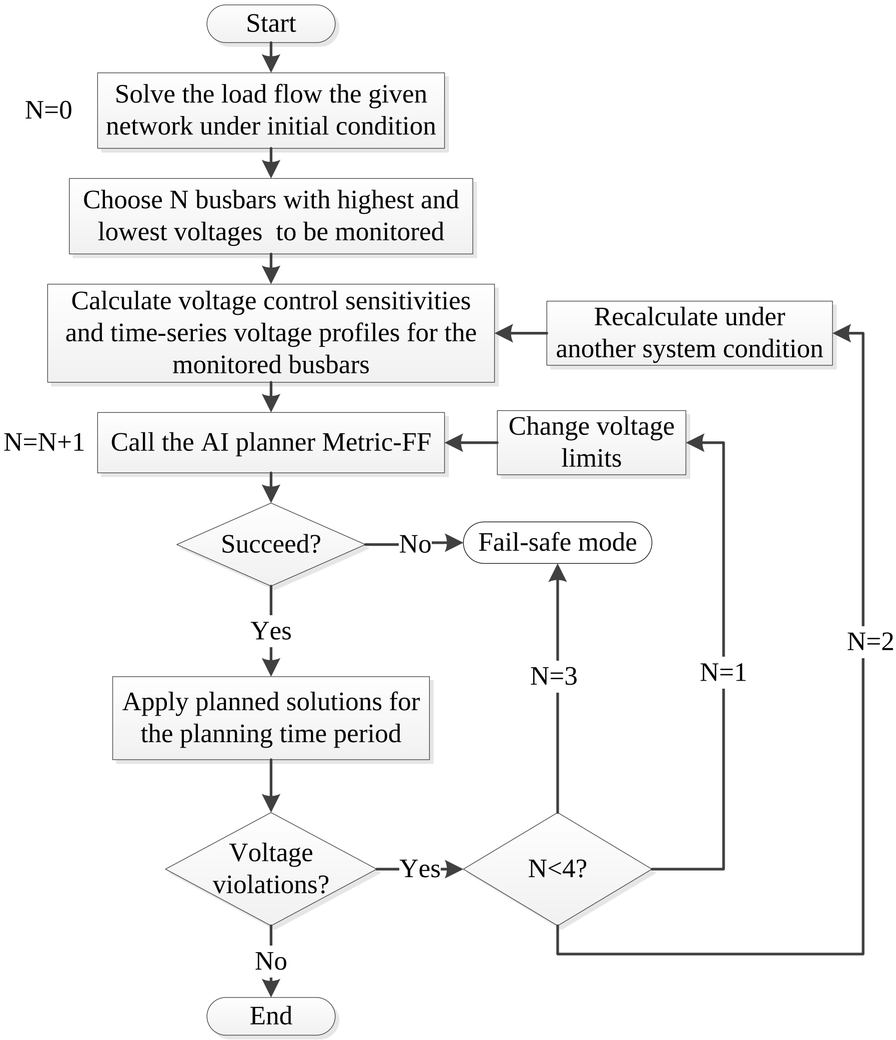


Figure 5-4 Flowchart of the proposed methodology

The proposed control strategy shown in Figure 5-4 is explained in terms of the following steps:

Step 1): Initialisation, sensitivity analysis & voltage calculation

Firstly, load flow is solved for a given distribution network under the initial system condition and a defined number of busbars with the highest and lowest voltages are identified as monitoring nodes in subsequent analysis. In case studies presented in chapter 6, two busbars with the highest voltages and two with the lowest voltages were chosen as a fair indication of the voltage performance in the studied distribution considering that extreme voltages tend to occur at the end of feeders in radial distribution networks. Normally, the nodes where loads are the heaviest and furthest from the distribution substation tend to experience the lowest voltages. By performing an initial load flow, the number of nodes can be decided depending on how far away the lowest voltages are from the requisite limits. The closer the voltages are to the limits, the more nodes need to be selected. Secondly, sensitivity matrices relating voltage changes at these monitored busbars to changes in control actions by voltage control equipment are calculated using equations (4-64), (4-67) and (4-71) respectively. Thirdly, with the ULTC transformers under fixed nominal tap settings, time series voltage profiles for the given load and generation profiles are obtained for the planning period, by executing load flow algorithms for each time slot or by applying equation (4-56) along with the relevant sensitivity matrices. The former option provides a more accurate approximation of the time series voltages at the expense of a slightly longer calculation time, while the results based on the latter method are less accurate but quicker.

Step 2): Scheduling of control actions and settings of target voltages using the AI planning approach

The time series voltage profiles at the selected busbars and the voltage control sensitivities derived from the first step are given to the AI planner along with the upper and lower voltage limits. Based on these descriptions of the problem, the AI planner will solve the voltage planning problem as an action scheduling task and schedule cost-effective solutions in terms of planned control actions by applying changes to the existing control settings when necessary. In the core of the planner, to settle underlying conflicts between the compliance of voltage limit and the minimisation of number of control operations and control action costs. Voltage control "costs" are modelled in a multi-objective function in equation (5-5):

$$PM = \alpha \times T + \beta \times M + \gamma \times LV + \delta \times HV \tag{5-5}$$

where PM is short for Planner Metric, referring to the total cost of the plan, which is the summation of costs of all the actions in the plan, α is the cost of each step in a transformer tap change operation, T is the total number of tap position step changes in the entire planning time period, β is the cost of each MSC switching action, M is the total number of switching actions for the MSC in the planning period, γ is the relative probability weighted 'cost' of the violation of the low voltage limit LV due to high demand and/or low DG output, δ is the relative cost of the violation of the high voltage limit HV due to low customer demand and/or high DG output. The constants α, β, γ and δ in the objective function represent the relative importance of the each factor.

The first two terms reflect the total control costs from planned control actions for the planning time period; the greater the constants, the fewer control actions the AI planner schedules. The assigned values for α and β can be obtained from consultancy with asset managers with regard to an estimation of the operational impact on equipment condition and lifetime in terms of costs. As mentioned in section 3.4, in the case studies carried out in this thesis, the cost per transformer tap change is the replacement cost of the asset divided by the total expected number of operations on tap changers in a transformer's lifetime (section 3.4.1) and similarly, the cost of switching an MSC is the cost of replacing the MSC's circuit breaker divided by the total expected number of switching actions in its life expectancy (section 3.4.2).

The latter two terms indicate the costs of voltage excursions beyond required voltage limits throughout the planning period; the greater the constants, the harder the AI planner tries to meet the requisite voltage limits. These two constants have the effect of enforcing respect of the voltage limits though at the risk, under extreme conditions, of no feasible plan being found. In this work, γ and δ are set to be infinity so that voltage limits are always respected. However, these values can be modified to reflect a less stringent compliance with the limits.

Specifically, the number of control changes scheduled by the planner is determined by the existing voltage levels at each time slot and the control sensitivities representing the control effect by an incremental change in control settings. The scheduled number of incremental changes should be able to improve the voltage profiles from outside the security limits to be inside. The AI planner estimates the time series voltages by applying voltage changes associated with planned control actions based on control sensitivities to the original time series voltages, as shown in equation (5-6).

$$V_{plan}^{t} = V_{orig}^{t} + S_{control} \cdot n_{control} \qquad (5\text{-}6)$$

where V_{plan}^{t} refers to the planned voltage target at time *t*, V_{orig}^{t} refers to the original voltage at time *t* before planning, $S_{control}$ is the voltage sensitivity due to the controls that occur at time *t*, $n_{control}$ is the number of scheduled control actions at time *t*. It should be noted that the sensitivities could be positive or negative and the polarity indicates the effect on voltages: a positive sensitivity means that the control action will increase the voltage profile, rice versa.

Step 3): Validation of planned solutions

Finally, the planner's suggested solutions in terms of control settings for voltage control equipment are applied to the given network for each time slot. Load flow algorithms are executed at each time slot and resultant time series voltage profiles are checked against the predefined limits. If there is no voltage violation, the planned results have achieved the planner's primary objective. The planned solutions are then compared with the conventional control approaches with regard to a range of factors: the number of voltage violations, the total number of any changes in control variables, the total control cost based on the number of incremental control change and the total system losses in megawatt-hour (MWh).

To indicate the wear-and-tear on the voltage control equipment due to planned control actions, two variables are also calculated for the entire planning period: the total number of control actions, i.e. the number of occurrence of any changes in control settings (whether it's one or two incremental step changes) and the total control costs. The planned solutions along with the conventional method are discussed based on the values of these two variables for different types of control mode. The total control costs across the planning time window are calculated on the basis of the number of incremental control changes and the cost per control operation as introduced in section 3.4. Control costs of transformer operations are calculated based on the number of tap step changes between two adjacent time slots and the defined incremental tap step. Control costs of MSC switching actions simply depend on the number of switching operations. Hence the total control costs cross the planning time period involve two terms, one is the cost of tapping up or down any of the transformers and the other is the cost of switching on or off an MSC, as shown in equation (5-7).

$$Control\ cost = \sum_{n=0}^{N}\sum_{t=0}^{T} TC \cdot \frac{T_{t+1}^{n} - T_{t}^{n}}{Step^{n}} + \sum_{q=0}^{Q}\sum_{t=0}^{T} SC \cdot (M_{t+1}^{q} - M_{t}^{q}) \qquad (5\text{-}7)$$

where *TC* refers to the tap cost per step change, *SC* refers to the switching cost of an MSC, T_{t+1}^{n}, T_{t+1}^{n} refer to tap position of transformer *n* at time *t+1* and *t* respectively, $Step^{n}$ refers to the incremental tap step change for transformer *n*, M_{t+1}^{q}, M_{t}^{q} refer to the status of capacitor *q* at time *t+1* and *t* respectively.

Step 4): Re-planning & failsafe operation

Given the inherent difference between the nonlinear nature of power systems and the AI planner's assumption of linearity, the planned solutions may not be able to eliminate all the initial voltage violations. In addition, in view of the likelihood that the network used by the planner could be modelled in a wrong way with incorrect parameters, or that the loads, generator outputs or branch statuses are different from what was assumed and used in the planning process, which would result in wrong sensitivities, the planner's suggested initial solutions might not see voltage fall outside limits when they may actually do. Therefore it is necessary to check planned solutions by running load flow algorithms based on updated demand and generation profiles or by observing current network conditions using available measurements and re-plan the voltage control problem to update the solutions when the time progresses to be closer to the real time.

Re-planning is required if, on being checked in load flow solutions for each time slot of the planning period, the planner's first attempted solutions fail to meet the requisite limits for any time slot. If the planned control actions are unable to keep voltage profiles within required limits at any time interval, two approaches can be adopted to improve the solutions: the first option is to adjust the parameters of voltage bounds for the planner on the basis of the polarity of voltage violations, i.e. raise the lower voltage limit when there is a lower voltage violation and lower the upper limit when the upper voltage limit is violated; the second option is to recalculate the voltage sensitivity factors for the particular time slots when voltages are outside limits. Both of these options will require a second execution of the AI planner under the new problem descriptions.

To cope with unlikely but possible failures of generating an appropriate plan having attempted the above two options, a regulatory fail-safe mode will be reverted to. The fail-safe control refers to applying localised voltage control methods such as generators' automatic voltage control and tap-changing transformers' fixed voltage target settings. The availability of this backup mode is also to deal with the potential loss of communications in relation to generation and demand forecast, system monitoring and control such as devices to monitor voltages and the capability to actuate control actions.

5.8 Advantages and Limitations

The proposed methodology takes advantage of the AI planning philosophy, power system sensitivity analysis and successfully integrates the two; to date no other method has taken this approach. The proposed methodology has the following advantages:

- In terms of the functionality of the methodology:
  - As an analytical tool, it is not entirely dependent on real-time data communications from network's measuring points to control centres.

  - It has less reliance on manual operation and engineering experience than conventional methods for controlling the ULTC transformers and MSCs in distribution networks.
  - It enables a feedback/re-plan loop to improve previous solutions if the solutions are not compliant with the requisite voltage limits.
  - It results in significant improvement of compliance with voltage limits.
  - It incurs less control operations and therefore a reduced total control costs over time compared to the conventional control methods.
  - Compared with the conventional optimisation and AI-related methods, the proposed approach is computationally easy and quick to solve and credible solutions can be generated provided that the network is accurately modelled.
- In terms of its practical implementation:
  - It is easy to implement and can potentially be applied to DNOs' existing software packages.
  - The planned solutions are easy for control engineers to interpret.
  - It does not require a rather large storage space and is quick to reach a planned solution unlike population based optimisation techniques.
  - It can serve as an off-line operational planning tool or an analytical tool for dealing with historical data.
  - The length of the planning time period and the time intervals are indefinite and therefore can be defined by users.

Due to the inherent difference between the linear planner and the non-linear power system, the proposed methodology may not always be able to generate a satisfactory plan for a given planning problem, i.e. there may be errors in the planning process. However, case studies in the following chapter suggested that planner errors seldom occur and in most cases, the proposed methodology gives acceptable solutions. Furthermore, the presence of a failsafe plan relieves the consequence of an inadequate plan. The proposed approach requires a good level of observability of the network to be studied or a credible model of the network with appropriate parameters.

The accuracy of the planned solutions depends on the available forecasts of demand and generation.

5.9 Summary

In this chapter, the proposed control methodology has been described in detail on the basis of information previously introduced in former chapters. AI planning has been introduced in this chapter as an important component of the proposed methodology.

The chapter has explained that the proposed methodology integrates an AI planning approach and the power system sensitivity analysis in order to produce a set of solutions for a given network model based on available generation and load data in time series and these results can be validated using power flow algorithms and corrected if erroneous.

6. Case Studies and Discussions

This chapter presents the case studies demonstrating the effectiveness of the proposed methodology when applied to a distribution network model, by illustrating the simulation results for different case scenarios and discussing the implications from the results.

6.1 Network Data and Simulation Procedures

In the following case studies, a 33/11kV test network model by courtesy of the Aura-NMS project shown in Figure 6-1 was used for its appropriate representation of a typical radial distribution system. There were 48 nodes, 24 loads, 51 lines, 2 ULTC transformers and 2 DGs in addition to a slack generator (representing grid power from transmission systems). The time series profiles of non-domestic demand in Figure 2-8 were used as in the following cases. Parameters for the network model as well as the demand and generation time series profiles are included in Appendix A.

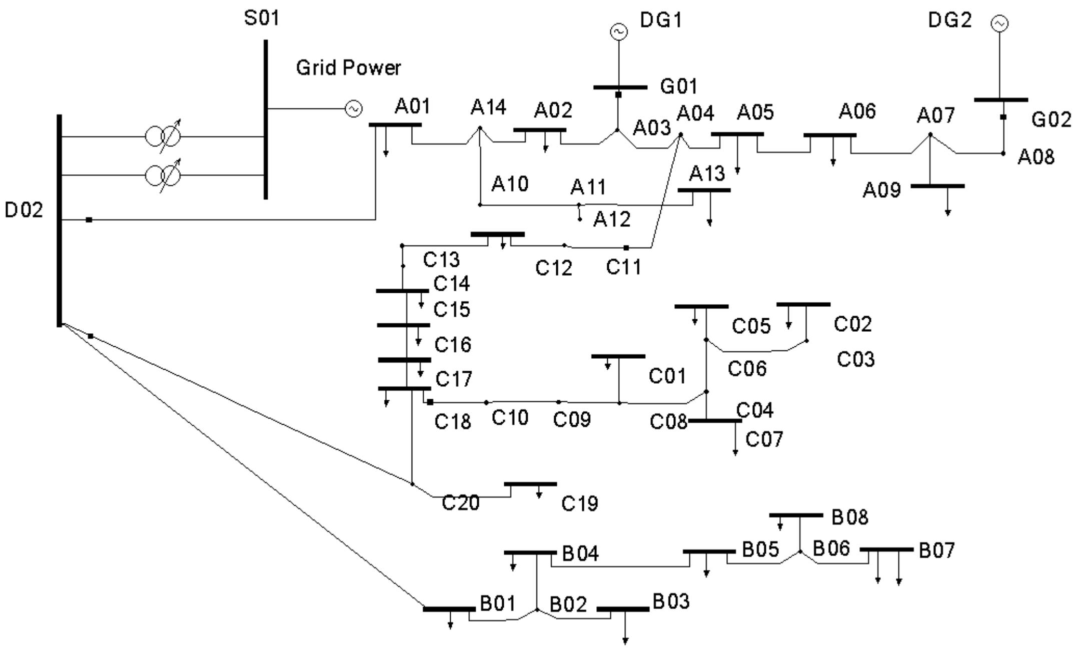


Figure 6-1 An MV-LV distribution network model (adapted from [27])

The two substation transformers share the same characteristics: the maximum and minimum tap ratios for each transformer were +10% and -10% respectively from the nominal position 0 with a ratio of 100%; the incremental tap step was 1.25%. It was assumed in the following case studies that the tap changers of these transformers were synchronised, i.e. the two transformers are always set on the same tap position to avoid unnecessary reactive power circulations. In addition, the value of deadband (DB) of the 33/11kV transformers is set to be equal to 1.25% to avoid excessive tap position changes [121]. Considering that ULTC transformers in distribution networks have been conventionally controlled via given target voltages under the AVC scheme, this control mode was simulated as a reference case (denoted as 'fv' in subsequent figures). Although DNOs may choose to change the constant target voltage for AVC schemes from the value of 1.0 per unit to be 1% higher during peak demand seasons, such a change in setting under unknown DG output might impose risks to the overall voltage profiles [52]. For example, the voltage profiles may become higher than usual when a number of DGs are exporting a rather large amount of power into the local distribution network. Therefore, it was assumed in the following case studies that the target voltage of 1.0 per unit was used for ULTC transformers as a reference.

As an initial case for the AI planner to improve upon, tap changers of ULTC transformers were set to be fixed at nominal positions under given load and DG time series profiles (with the notation of 'fc') and the voltage control sensitivities are calculated based on the initial condition. The corresponding time-series voltage profiles for a selected number of busbars were obtained by load flow results and the AI planner was applied based on the voltage profiles and voltage sensitivities to generate a sequence of planned control settings (with the notation of 'pc'), i.e. tap positions for the transformers and switching status for capacitors. The planned control settings were then applied to the system model and the resultant time series voltages at the regulated busbars such as the LV side of an ULTC transformer were used as planned target voltages for the transformers' AVC scheme (with the notation of 'pcv') to check if the resultant tap changing operations are consistent with the original planned control settings. Therefore, the planned results took two forms:

planned control settings and planned voltages. This offers operators the flexibility to choose either to set the tap changer positions for the ULTC transformers at certain time slots or to set the target voltages for the AVC scheme for the transformers.

The model was simulated on a half-hourly basis for 24 hours starting from midnight. It was assumed in the case studies that the input data, i.e. the distribution model and forecasted day-ahead time series generation and demand profiles, were available, accurate and appropriate for system studies. The general simulation procedures are outlined as follows:

1. Initialisation of a given electrical network model:
   Obtain the parameters for voltage control equipment such as the maximum, minimum and current tap positions of ULTC transformers; solve the given network for the initial time slot of the predicted generation and loading profiles, calculate voltage control sensitivities and identify the busbars whose voltages need to be monitored for the AI planner to consider;
2. Description of the voltage planning problem:
   Set the tap changers of transformers to be fixed at nominal positions (fc) and obtain the resultant time series voltage changes between every two consecutive time slots under the given time series profiles of generation and demand for each time slot; [19]
3. Execution of the AI planner:
   Use the time series voltage changes at the monitored busbars (from step 2), control device settings and sensitivity factors (from step 1) as inputs to the AI planner to obtain a scheduled sequence of control settings for voltage control equipment (pc) and estimated voltages at the monitored busbars;
4. Validation of planned results:
   Apply the planned sequence of control settings for each of the control equipment to obtain the relevant time series voltage profiles at the

[19] The nominal position is usually at the mid-point of the tapping range, but in some cases, it could also be fixed at other positions. In this thesis, it is assumed that the nominal position is the mid-point of the tapping range for a ULTC transformer and that the tap changers are at the neutral positions at the initial condition.

transformer busbar and use these voltages as the target voltage settings for the transformers under AVC schemes to solve for the corresponding tap positions and resultant voltage profiles at each time slot (pcv);

5. Simulation of the conventional approach:
   Set the target voltages for ULTC transformers to be 1.0 per unit and execute load flow calculations for each time interval under given time series profiles of generation and demand to obtain a sequence of tap positions and resultant network voltages;
6. Comparison of simulation results:
   Compare the planned solutions against the conventional control approach in terms of the number of voltage limit violations, the number of changes in equipment status/settings and the associated control costs.

The objective of the proposed methodology is to plan control actions so that a minimal number of control actions are used to meet the requisite voltage limits. Therefore, for all of the studied cases in this chapter, the simulation results for each control mode were summarised in terms of the number of voltage violations, number of control actions and associated control costs. Specifically, the number of voltage violations across the network at all time slots was recorded for each control mode in order to check the compliance with requisite voltage security limits. The total number of tap changing operations (i.e. the sum of occurrences of any change in tap position from one time slot to the following time slot) and the number of MSC switching actions were also observed for each control mode. For example, if a transformer changed its tap changer position from 1 at 04:00 to 3 at 04:30, the number of tap changing operations will increase by 1. Also shown in the simulation results are the total control costs calculated using equation (5-7) based on the total number of incremental tap position changes of ULTC transformers and the total number of status switching operations for MSCs throughout the planning time period. As in the previous example, the control cost incurred by the tap changing action during the two time slots will be the given cost per tap change multiplied by 2. The control costs of actuating an incremental tap change (assuming that tap changers are mechanical) and switching an MSC were merely indicative and set to be 0.1 and 0.05

respectively. This setup is to prove that the AI planner is capable of using the relatively cheaper control action out of available options. As an indication of different control mode's impact on system losses, the total losses in MWh were also noted for each control mode, that is, the sum of the MW losses in each hour over the planning time period.

The two DGs in the studied distribution network were assumed to be of wind power; the time series generation profiles were obtained at a UK generation site on a winter day in January and provided by the courtesy of Dr Thipnatee Sansawatt in SPEN. Although many DNOs currently prefer DGs to operate with a unity power factor to avoid potential undesired interference with the existing system management schemes, the following case studies explored the interaction between different generator control modes and the substation transformer AVC schemes [59][143]. The control modes of power factor control (PFC) and AVR for generators were studied in the subsequent sections, because these two modes adequately represent the actual operation of the major types of operating wind farms. That is, wind turbines that are connected to the grid using synchronous generators (such as FRC-based wind turbines) are typically capable of producing reactive power and therefore can be considered to have AVR control. DFIG-based wind turbines also have reactive power capability and thus may be available for AVR control. FSIG-based wind turbines do not possess intrinsic, controllable reactive power capability and typically require capacitors on-site for power factor correction purpose; therefore, with suitable control of the onsite reactive compensation, the operation of this type of wind generator can be deemed as under PFC mode [135]. The time series demand and generation data are all included in the Appendix A.

Considering that voltage profiles in distribution networks are largely dependent upon loading and generation conditions, the following two major scenarios were considered in this chapter: low voltage scenarios at times of winter maximum demand with normal DG output and high voltage scenarios at time of summer minimum demand with high DG generation. Winter maximum demand was of non-domestic type and assumed to be 200% relative to the normal loading condition.

Summer minimum demand was of domestic-type and assumed to be 40% of the normal loading condition. Both loading profiles included economy seven and unrestricted customers as introduced in section 2.4.2.2 and the plots of time series profiles were as shown in Figure 2-8. Considering that the distribution network is heavily loaded during winter and thus voltages tend to be lower than usual, the time series profiles of minimum voltages experienced across the network were observed for the winter cases and those of the maximum voltages were observed for the summer cases.

6.2 Case 1: Winter Scenario

In this section, tap position settings and target voltage settings of ULTC transformers and DGs' control mode as well as the status of MSCs were studied under the winter maximum loading condition. Although low voltages tend to occur with high levels of demand and low levels of generation, DGs were assumed to be producing a normal amount of active power so that it is capable of exporting an appreciable amount of reactive power to the network. The time series profile of the power output by each of the DGs is depicted in Figure 6-2.

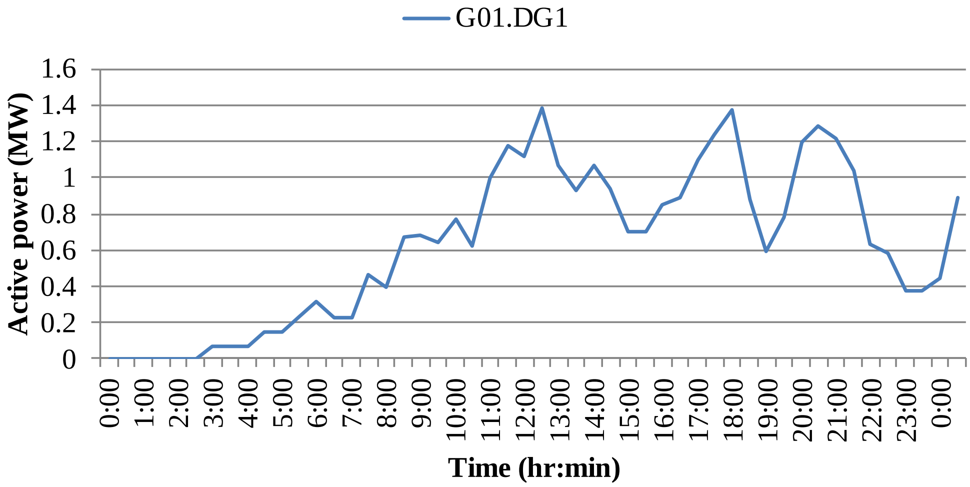
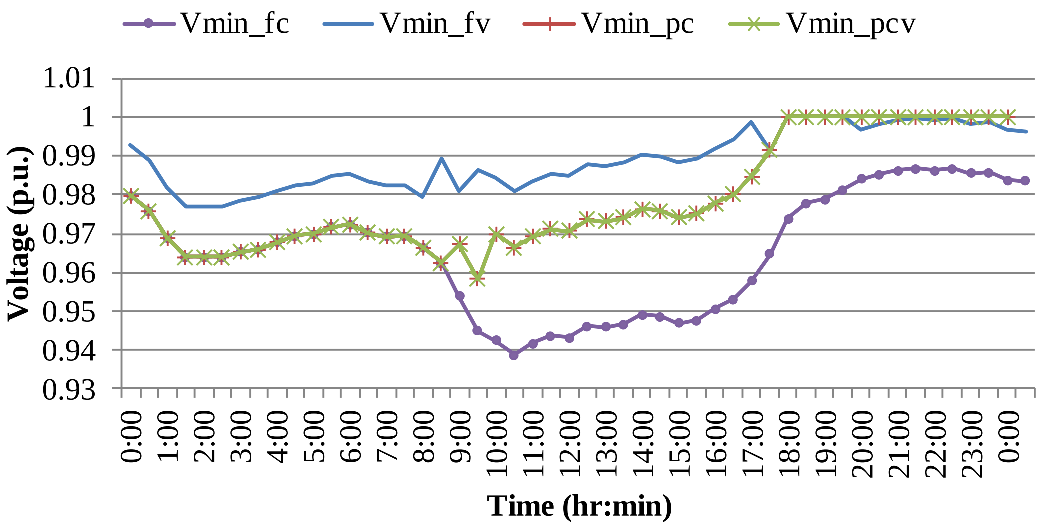


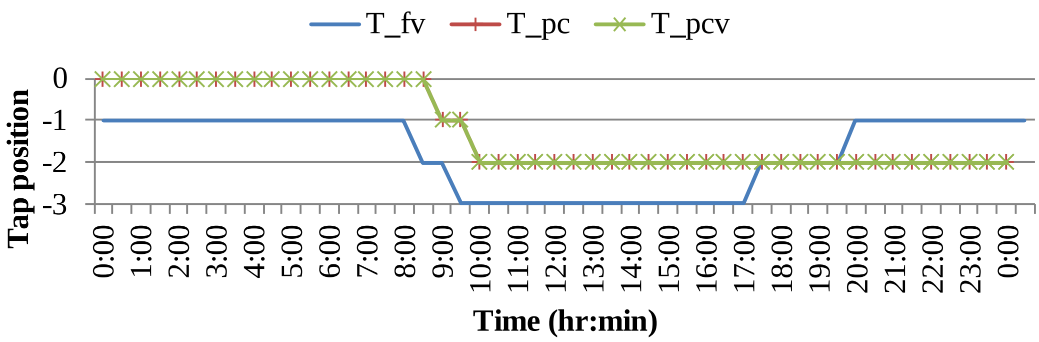
Figure 6-2 Daily time series profile of wind power output for case 1

6.2.1 Case 1a: Transformer and DG PFC

In this case, it was assumed that the capacity of each of the DGs was 2MW and that both DGs were under power factor control (PFC) mode with a lagging power factor of 0.95. The minimum voltages experienced across the network at each time slot and transformers' tap changer positions were depicted in Figure 6-3; the total number of voltage violations and control operations as well as associated costs were summarised in Table 6-1.



(a) Minimum voltages



(b) Transformer tap positions

Figure 6-3 Time series profiles of minimum voltage and tap positions - case 1a

Table 6-1 Case summary - case 1a

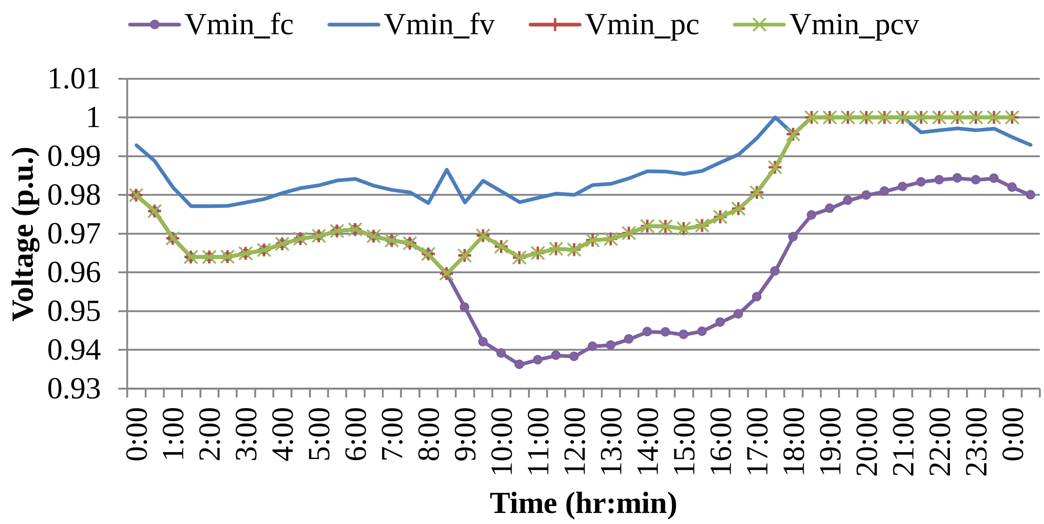
Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MW)
Nominal control	1	0.938869	394	0	0	2.1831705
Fixed voltages	1.011912	0.977104	0	8	0.8	2.043702
Planned control	1.019282	0.958335	0	4	0.4	2.0901775
Planned voltages	1.019282	0.958335	0	4	0.4	2.090185

It can be seen from Figure 6-3 (a) and Table 6-1 that when the tap changers of ULTC transformers were set to be at the nominal position (as indicated by the purple curve denoted as fc), the minimum voltage fell beyond the lower voltage limit of 0.95 per unit at the time window from 09:30 to 17:30, leading to a total of 394 voltage violations. The AI planner's scheduled tap position settings eliminated voltage violations (as indicated the red curve denoted as pc) by moving the tap changers from the nominal position to the position of -1 and -2 at 09:00 and 10:00 respectively, thus resulting in a total control cost of 0.4 on the two transformers. The same results were observed when the resultant transformer voltages from the planned tap settings (as indicated the green curve denoted as pcv) were used as target voltages to enable load flow algorithms to automatically adjust tap changers. It should be noted, however, that the adjustment of tap changers are executed by the AVC schemes for ULTC transformers in practice.

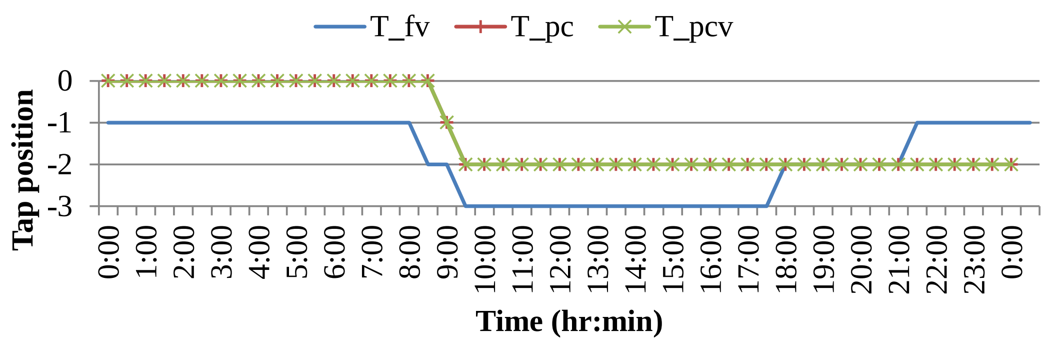
In the meantime, the conventional approach, the fixed target voltage setting of 1.0 per unit for tap changers (as indicated the blue curve denoted as fv), did not violate any voltage limits across the planning time period, but started from a non-nominal position of -1 and led to incremental changes in tap position settings at 08:30, 09:30, 17:30 and 20:00 respectively in order to ensure that the voltage at the transformer busbar is relatively close to the target setting of 1.0 per unit at all time slots; it can be observed from Figure 6-3 that the average minimum voltage was higher than 0.98 per unit and closer to 1.0 per unit throughout the planning time period. The resultant tap changer operations incurred a total control cost of 0.8, two times higher than that of planned solutions. This implies that tap changer operations tend to be more frequent when a constant target voltage is used for automatic tap changer control scheme. Therefore, it can be concluded that, with DGs under PFC mode, planned tap position settings and the resultant voltages for transformers both resulted in lower control costs, compared with the conventional fixed target voltage settings.

6.2.2 Case 1b: Transformer and DG UPF

In this section, the tap changing operations were studied under the winter scenario with the DGs operated at a unity power factor (UPF). The time series voltage profiles of the minimum voltages along with the tap changing operations for each of the studied transformer control modes were depicted in Figure 6-4 and the results were summarised in Table 6-2.



(a) Minimum voltages



(b) Transformer tap positions

Figure 6-4 Time series profiles of minimum voltage and tap positions - case 1b

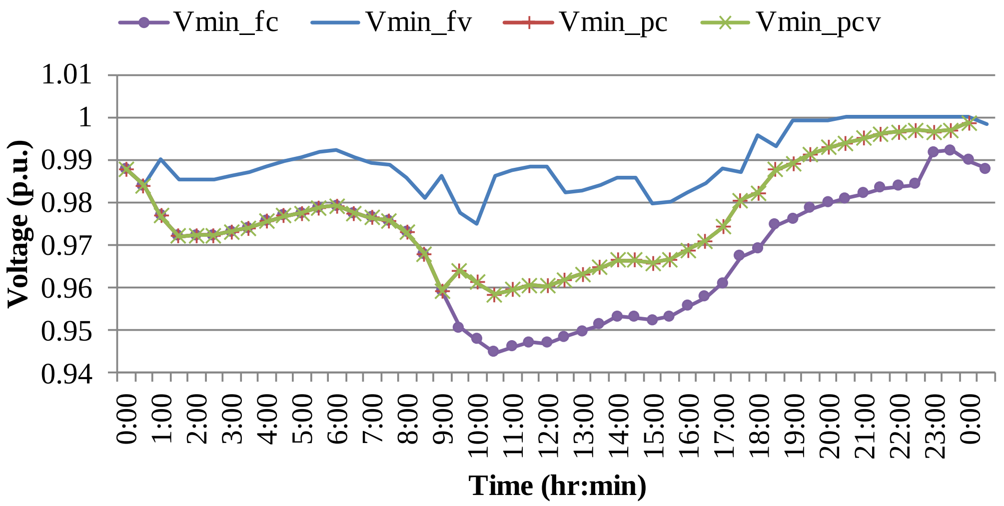
Table 6-2 Case summary – case 1b

Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MW)
Nominal control	1	0.936152	556	0	0	4.577577
Fixed voltages	1.014223	0.977104	0	8	0.8	4.277261
Planned control	1.014483	0.959625	0	4	0.4	4.372775
Planned voltages	1.014483	0.959625	0	4	0.4	4.372967

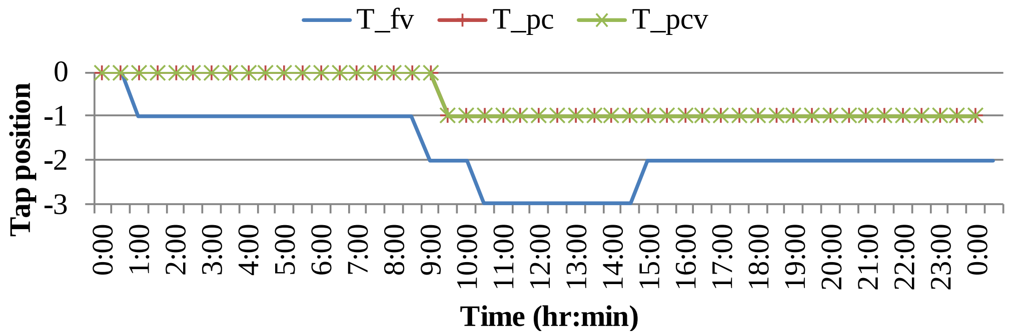
By comparing the results in Table 6-1 and those in Table 6-2, it could be seen that, there was more voltage violations when the DGs were operated with a unity power factor due to lack of insufficient reactive support in the local network. Nonetheless, the planned solutions were the same as the ones for case 1a in terms of the total number of changes in control settings and the associated control costs, although the timing of the second control action was relatively advanced.

6.2.3 Case 1c: Transformer and DG AVR

In this case, the two DGs were assumed to be under AVR control with reactive power limits set to be the power factor of 0.95 leading and lagging. The time series profiles of the minimum voltages experienced across the network and tap-changing operations of transformers were depicted in Figure 6-5 and the number of voltage violations, control operations and associated costs were summarised in Table 6-3.



(a) Minimum voltages



(b) ULTC transformer tap positions

Figure 6-5 Time series profiles of minimum voltage and tap positions - case 1c

Table 6-3 Case summary - case 1c

Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Nominal control	1	0.944893	164	0	0	2.0756115
Fixed voltages	1.007863	0.975043	0	8	0.8	2.0729875
Planned control	1.003168	0.958413	0	2	0.2	2.0278925
Planned voltages	1.003168	0.958428	0	2	0.2	2.031457

It can be seen from the plot in (a) of Figure 6-5 and the content in Table 6-3 that under the fixed nominal tap position settings, the minimum voltage experienced across the network fell below 0.95 per unit at the time window from 10:00 to 13:00, resulting in a total number of 164 voltage violations, significantly less than that of case 1a when DGs were under PFC. The reduced number of voltage violations is due to the DGs' enhanced reactive power capability (with the maximum and minimum VAr limits set to be the lagging and leading power factor of 0.95). In the meanwhile, the fixed target voltage of 1.0 per unit did not lead to any voltage violations but changed tap positions at 01:00, 09:00, 10:30 and 15:00 respectively throughout the planning period to keep the actual voltage at the transformer to be close to 1.0 per unit and hence incurred a total control cost of 0.8 on the two transformers, the same as case 1a.

In this case, the AI planner's scheduled tap position settings and the resultant voltage settings also ensured that voltages remain within requisite limits throughout the planned period. Specifically, the AI planner changed the tap changer settings from the nominal position 0 to -1 at 09:30, leading to a total control cost of 0.2. When the planned tap positions' resultant voltages were used as target voltages for the transformer AVC schemes, the tap changer operations were the same as the planned tap position settings during the planning time period.

Comparison of case 1a and case 1c

The conventional approach and planning approach for the two control modes for DGs were compared and summarised in Table 6-4. By comparing the conventional fixed target voltage approach in case 1a (as summarised in Table 6-1) and case 1c (Table 6-3), it can be seen that the total control costs were the same under the PFC and AVR control modes although the timings of the tap changing operations were different; the active power losses were marginally higher for the AVR control mode ('fv' mode) than the PFC mode with a difference of 0.0293MWh. It can be also observed that, regarding the planning approach, the control costs were cheaper by 50% and the losses were less by 0.0623MWh for the AVR mode than the PFC mode. In the meantime, the planning approach with DGs under AVR control mode led to a cheaper control cost than the conventional fixed target approach with the DGs under PFC mode.

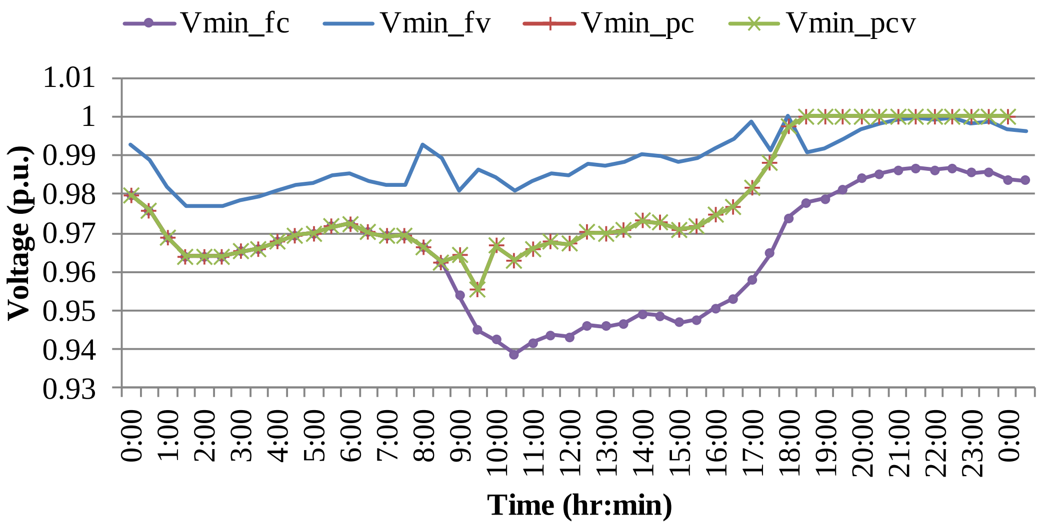
Table 6-4 Comparison of case 1a and 1c

Transformer control	*DG control mode*
Conventional approach	The same control cost for AVR and PFC mode, marginally lower losses for DG PFC mode than AVR mode
Planning approach	Less control cost and less losses for AVR mode than PFC mode

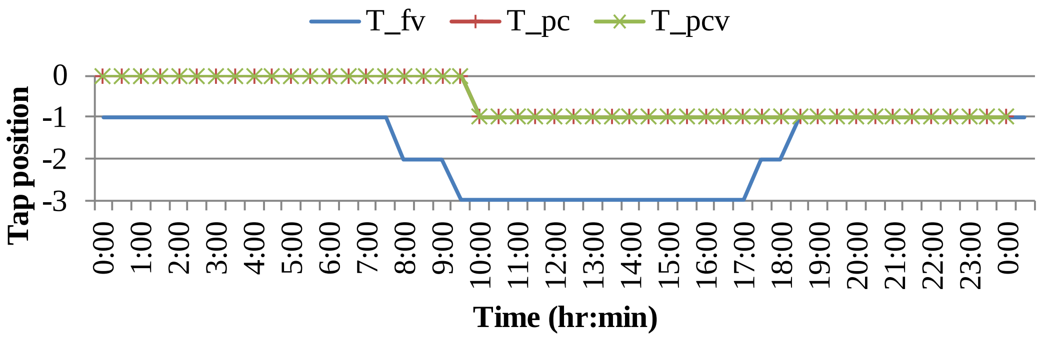
6.2.4 Case 1d: Transformer, DG PFC and MSC

In this case, in order to study the coordination of ULTC transformers and an MSC, it was assumed that one capacitor was installed at node C20, where one of the distribution feeders terminate and a number of loads were supplied from, in order to best compensate the heavily loaded part of the distribution network. The control cost of switching on or off an MSC was assumed to be lower than the cost of changing the transformer tap positions, as discussed in section 3.4. That is 0.05 for each switching action of the MSC and 0.1 for an incremental change in transformer tap positions. The two DGs were assumed to be under PFC mode.

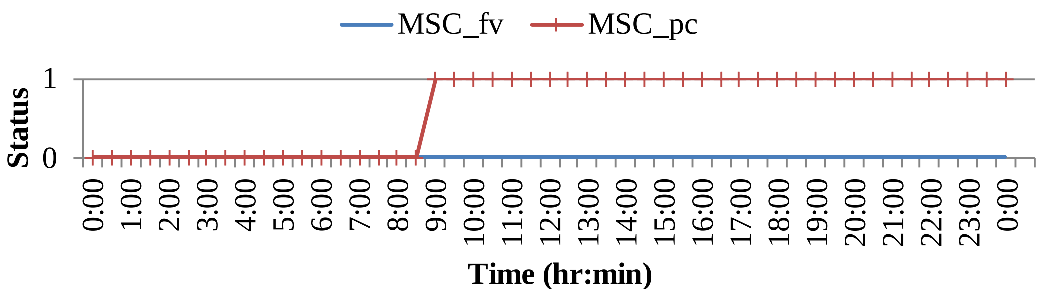
It should be noted that, for the conventional control mode, the MSC was assumed to be under local automatic control that has a low voltage threshold of 0.94 per unit, i.e. the MSC will be switched on if the local voltage falls below 0.94 per unit. This assumption is made based on the fact that very few MSCs are currently used in the UK distribution networks and it is likely that these MSCs are operated under automated local controls rather than a coordinated control scheme as the ARS scheme in transmission systems [39]. MSCs tend to have a relatively lower voltage threshold setting (or a higher DB setting) than transformers because the switching action of an MSC or a number of capacitors normally leads to a greater change in voltage magnitude. Compared with transformer tap-changing operations, the switching operation of an MSC or an MSR is relatively less frequent since switching actions normally only occur when a moderately large step change is required or a reasonable amount of MVAr reserve is needed. The time series profiles of the minimum voltages experienced at the network, tap changer operations and MSC status were depicted in Figure 6-6; the simulation results were summarised in Table 6-5.



(a) Minimum voltages



(b) ULTC transformer tap positions



(c) MSC on/off status

Figure 6-6 Time series profiles of minimum voltage, tap positions, MSC status - case 1d

Table 6-5 Case summary - case 1d

Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Nominal control	1	0.938869	394	0	0	2.1831705
Fixed voltages	1.0085	0.977104	0	8	0.8	2.0439765
Planned control	1.016514	0.955225	0	3	0.25	2.083261
Planned voltages	1.016514	0.955225	0	3	0.25	2.083204

It can be seen from Figure 6-6 and Table 6-5 that the fixed nominal tap position settings resulted in 394 voltage violations at the time window from 09:30 to 16:00. The conventional method, i.e. the fixed target voltage for transformer AVC schemes and the local automatic control of the MSC, did not lead to any voltage violations. This is because the fixed 1.0 p.u. target voltage for the transformers eliminated voltage violations by adjusting the tap positions at 08:00, 09:30, 17:30 and 18:30, leading to a total control cost of 0.8, the same as that of case 1a. In this control mode, owing to the tap changing operations, the lowest voltage seen by the MSC during the planning time period was about 0.99 per unit, well above the low voltage threshold of 0.94 per unit, as seen in Figure 6-7. Therefore, no MSC switching action was seen under local control, shown in (c) of Figure 6-6.

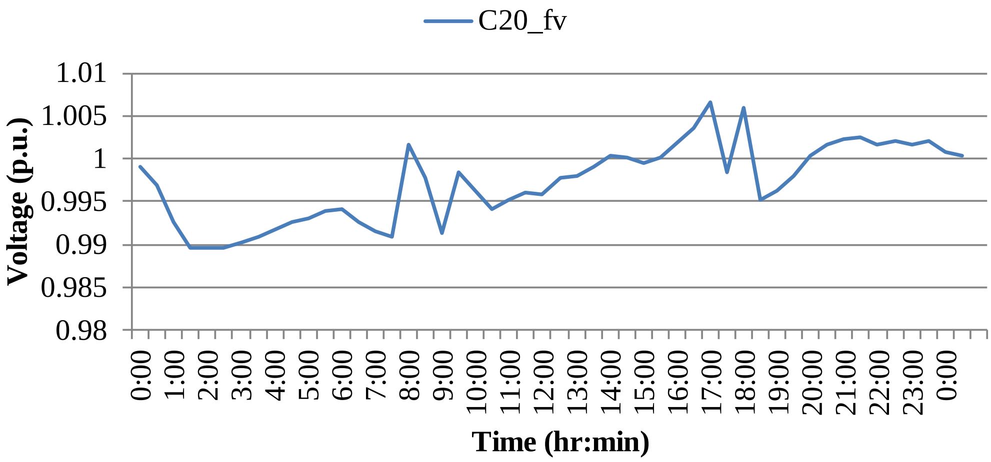
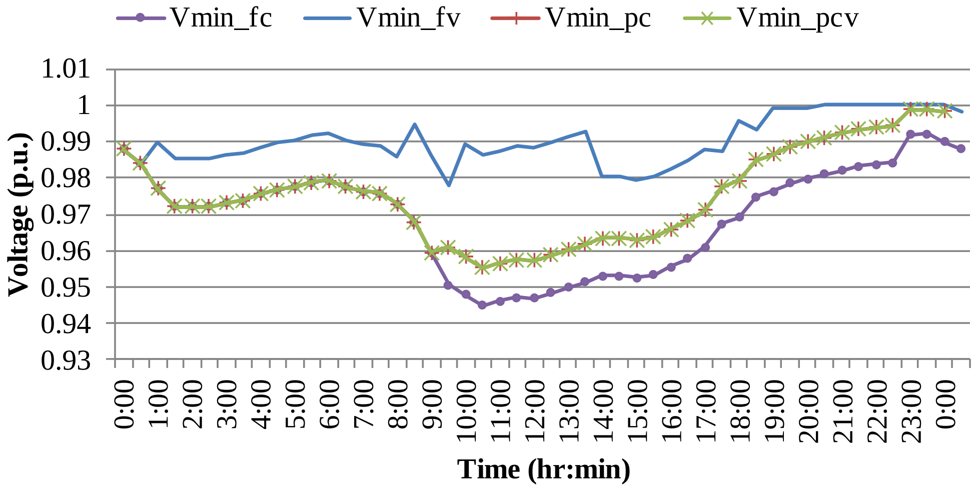


Figure 6-7 Time series profile of voltage at the MSC-connected node C20 – case 1d

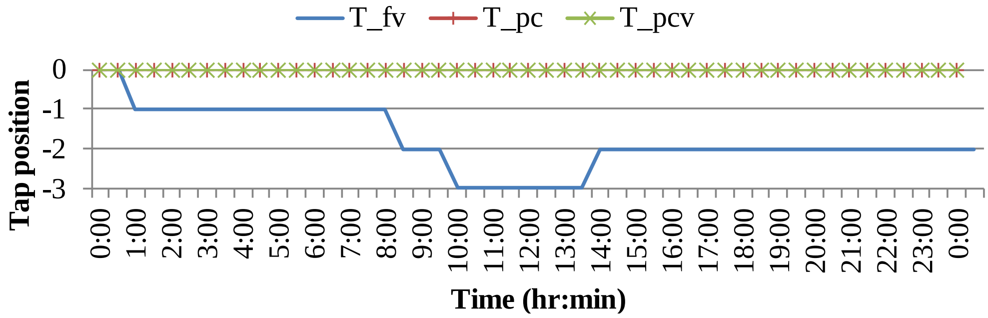
Regarding the planned control actions, the AI planner scheduled the MSC to be switched on at 09:00 to improve the minimum voltage from below 0.95 per unit and also tapped down the transformer tap changers at 10:00 to improve the minimum voltage from below 0.94 per unit, leading to a total control cost of 0.25, 0.2 for tapping the transformer tap changers and 0.05 for switching on the MSC. The case summary in Table 6-5 showed that the maximum voltage at the network rose to 1.0165 per unit because of the MVAr compensation by the MSC, marginally higher than that of the conventional 1.0 per unit AVC target setting, but still well within the upper voltage limit. The same results were observed when the planned tap positions' resultant voltages were used. In this case, both planned control settings (i.e. transformer tap positions and MSC status) and resultant target voltages eliminated voltage violations at a much lower cost compared with the conventional control approach.

6.2.5 Case 1e: Transformer, DG AVR and MSC

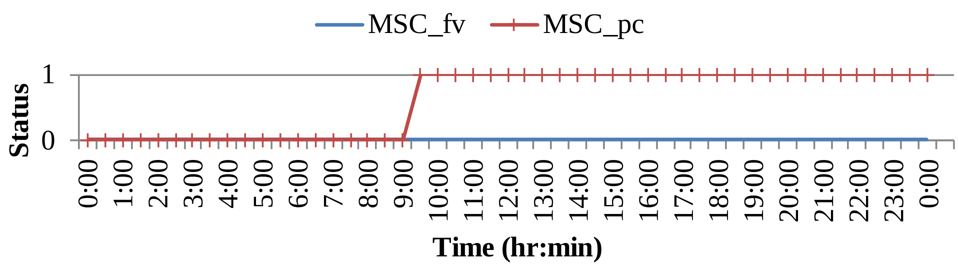
In this case, the two DGs were assumed to be under AVR mode and the rest of the network conditions and assumptions are the same case 1d. The time series profiles of the minimum voltages experienced across the network, tap changer operations and MSC status were depicted in Figure 6-8; the simulation results were summarised in Table 6-6.



(a) Minimum voltages



(b) ULTC transformer tap positions



(c) MSC on/off status

Figure 6-8 Time series profiles of minimum voltage, tap positions, MSC status - case 1e

Table 6-6 Case summary - case 1e

Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Nominal control	1	0.944893	164	0	0	2.0756115
Fixed voltages	1.007863	0.977804	0	8	0.8	2.0278215
Planned control	1.002359	0.955297	0	1	0.05	2.01712
Planned voltages	1.002359	0.955323	0	1	0.05	2.0204825

It can be seen from Figure 6-8 and Table 6-6 that the fixed nominal tap position settings resulted in 164 voltage violations at the time window from 09:30 to 13:00, much less than that of case 1d. The conventional methods, i.e. the fixed target voltage for transformer AVC schemes and the local automatic control of the MSC, did not lead to any voltage violations. This is because the fixed 1.0 p.u. target voltage for the transformers eliminated voltage violations by adjusting the tap positions at 01:00, 08:30, 10:00 and 14:00, leading to a total control cost of 0.8, the same value as that of case 1d. In this control mode, owing to the tap changing operations, the lowest voltage seen by the MSC during the planning time period was about 0.99 per unit, well above the low voltage threshold of 0.94 per unit, as seen in Figure 6-9. Therefore, no MSC switching action was seen under local control, shown in (c) of Figure 6-8.

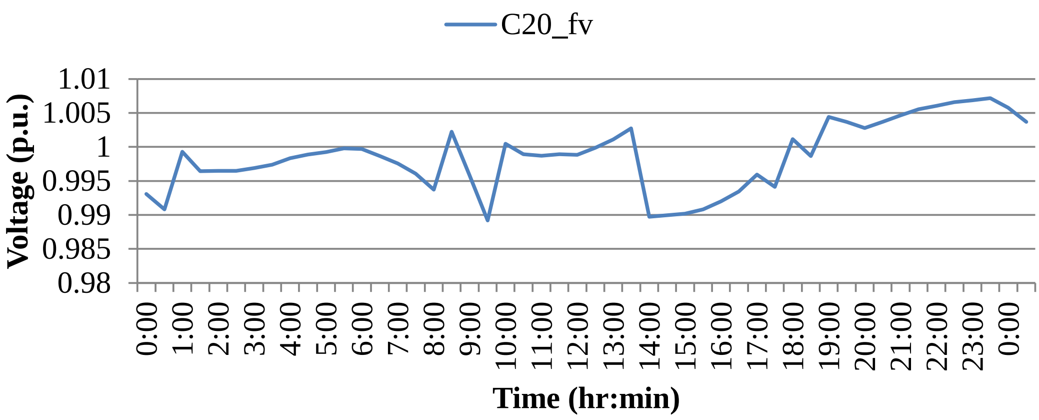


Figure 6-9 Time series profile of voltage at the MSC-connected node C20 – case 1e

As for the planned control actions, instead of using the ULTC transformers, the AI planner scheduled the MSC to be switched on at 09:30 to improve voltage profiles due to the lower control cost for using the MSC (a control cost of 0.05 by switching on the MSC). The same results were observed when the planned tap positions' resultant voltages were used. In this case, both planned control settings (i.e. transformer tap positions and MSC status) and resultant target voltages eliminated voltage violations at a much lower cost compared with the conventional control approach.

Comparison of case 1d and case 1e

The conventional approach and planning approach for the two control modes for DGs were compared and summarised in Table 6-7. By comparing the conventional fixed target voltage approach in case 1d and case 1e, it can be seen that the total control costs were the same when the DGs were operated under PFC and AVR control modes although the timings of the tap changing operations were different; the active power losses were slightly higher for the PFC control mode than the AVR mode with a difference of 0.0162MWh. It can be also observed that, regarding the planning approach, the control costs were cheaper by 2.0 and the losses were less by 0.0661MWh for the AVR mode than the PFC mode. In the meantime, the planning approach with DGs under AVR control mode was the cheapest option that also had the least losses.

Table 6-7 Comparison of case 1d and 1e

Transformer control mode	*DG control mode*
Conventional approach	The same control costs for AVR and PFC mode, marginally lower losses for DG AVR mode than PFC mode
Planning approach	Less control cost and less losses for AVR mode than PFC mode

6.3 Case 2: Summer Scenario

In this section, tap position settings and target voltage settings of ULTC transformers and DGs' control mode were studied under the summer minimum loading condition. To evaluate high voltage profiles due to the export of active power by DGs, it was assumed that each of the DGs' capacity was set to 7MW. The daily time series profile for the two DGs is shown in Figure 6-10.

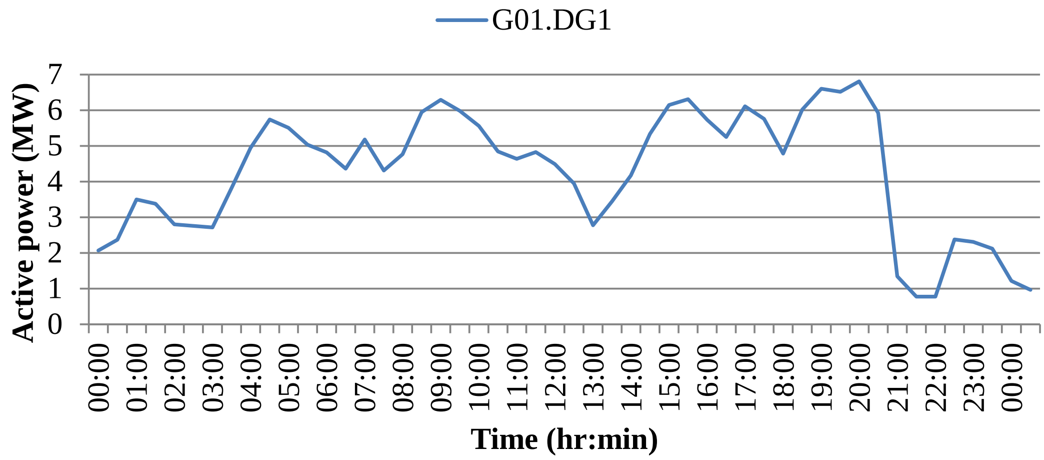
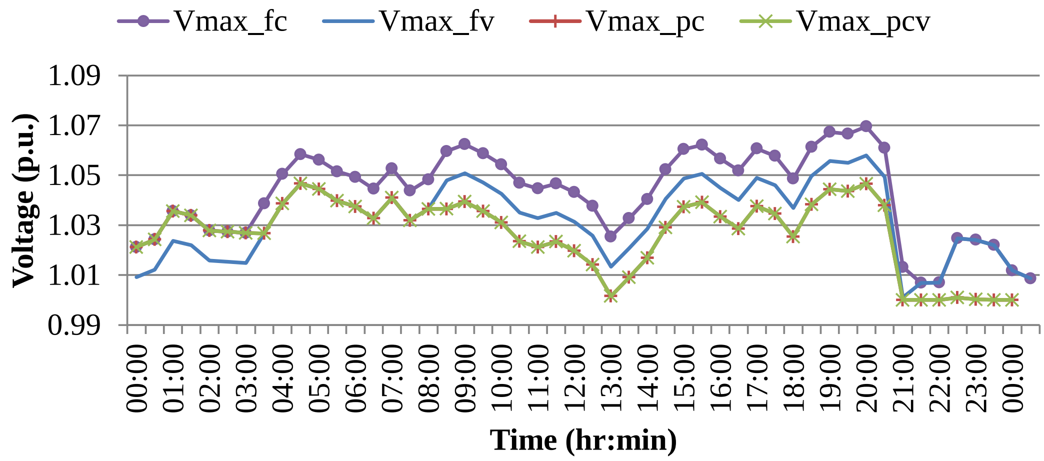


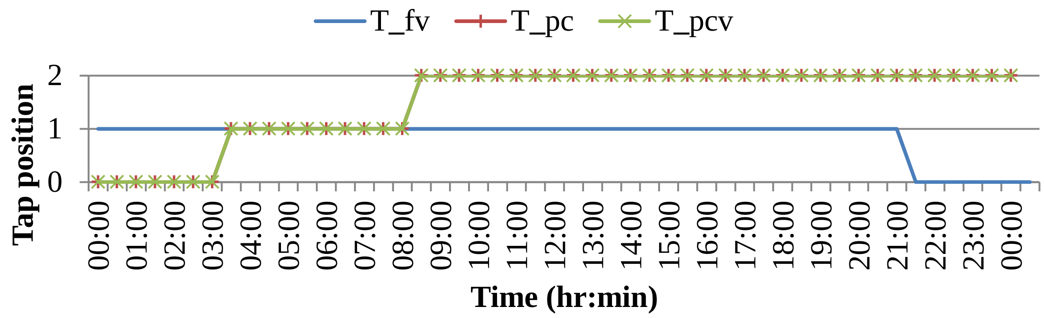
Figure 6-10 Daily time series profile of wind power output for case 2

6.3.1 Case 2a: Transformer and DG PFC

In this case, it was assumed that DGs were under power factor control (PFC) mode. That is, a fixed setting of 0.95 lagging was used. The maximum voltages experienced across the network at each time slot and the transformers' tap changer positions were depicted in Figure 6-11; the total number of voltage violations and control operations as well as associated costs were summarised in Table 6-8.



(a) Maximum voltages



(b) Transformer tap positions

Figure 6-11 Time series profiles of maximum voltage and tap positions - case 2a

Table 6-8 Case summary - case 2a

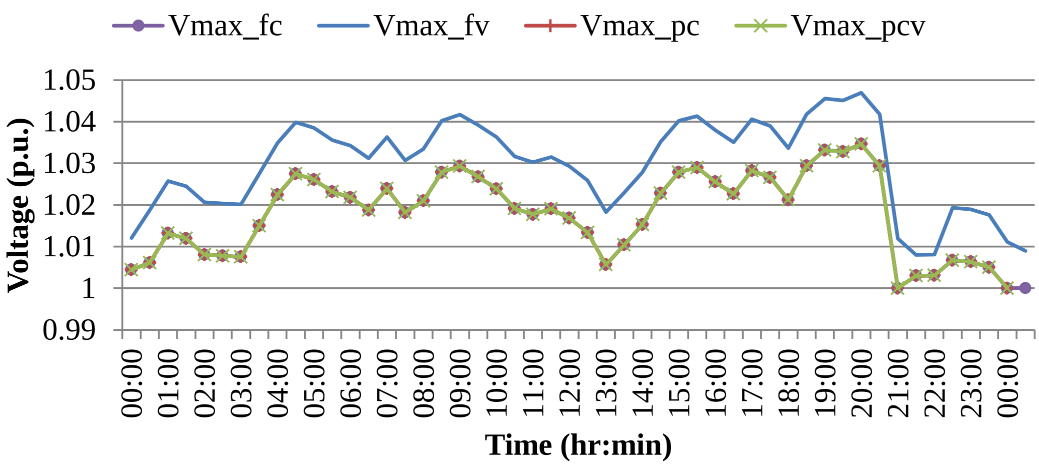
Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Nominal control	1.069525	1	41	0	0	5.547605
Fixed voltages	1.057906	0.990255	9	2	0.2	5.667935
Planned control	1.046694	0.976513	0	4	0.4	5.771145
Planned voltages	1.046694	0.976513	0	4	0.4	5.76977

It can be seen from the (a) in Figure 6-11 and Table 6-8 that when the tap changers of ULTC transformers were set to be at the nominal position, the maximum voltage reached higher than the upper voltage limit of 1.05 per unit at a number of time windows: from 04:00 to 05:30, from 08:30 to 10:00 and from 15:00 to 20:30, resulting in a total number of 41 voltage violations. The AI planner's scheduled tap position settings eliminated these voltage violations by moving the tap changers from the nominal position to +1 position at 03:30 and to the position of +2 at 08:30, resulting in a total control cost of 0.4 on the two transformers. The same results were observed when the resultant transformer voltages from the planned tap settings were used as target voltages to enable load flow algorithms to automatically adjust tap changers.

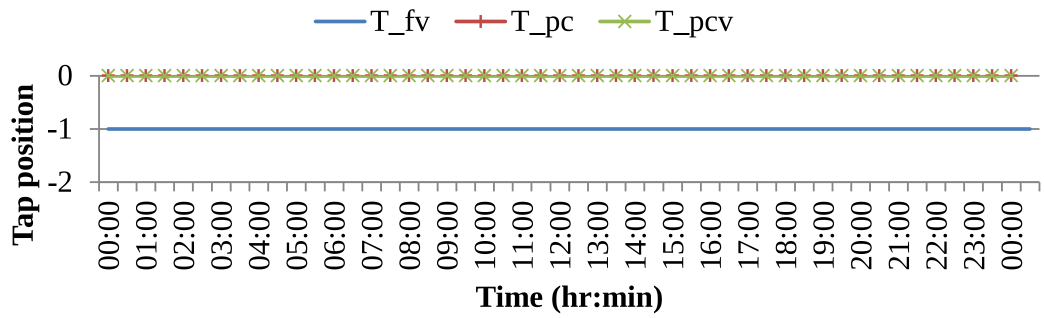
The simulation results for the conventional fixed voltage target approach showed that the tap positions were set to be at the position of +1 from 00:00 to 21:00 before changing to the nominal position, leading to a total control cost of 0.2. However, the upper limit was violated from 19:00 to 20:00 under this control approach.

6.3.2 Case 2b: Transformer and DG AVR

In this case, the two DGs were assumed to be under AVR control with reactive power limits set to be the power factor of 0.95 leading and lagging. The time series profiles of the maximum voltages experienced across the network, tap changer operations of ULTC transformers were depicted in Figure 6-12 and the total number of voltage violations and control operations and associated costs were summarised in Table 6-9.



(a) Maximum voltages



(b) Transformer tap positions

Figure 6-12 Time series profiles of maximum voltage and tap positions - case 2b

Table 6-9 Case summary - case 2b

Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Nominal control	1.034633	0.986274	0	0	0	5.46559
Fixed voltages	1.046945	0.998219	0	0	0	5.3342
Planned control	1.034633	0.986274	0	0	0	5.458625
Planned voltages	1.034621	0.986275	0	0	0	5.456525

It can be seen from the plot in (a) of Figure 6-12 and the content in Table 6-9 that under the fixed nominal tap position settings, the maximum voltage experienced across the network were well within the requisite upper limit, i.e. no voltage violation was observed. This is because of the reactive power support regulated by the AVR of the two DGs. In this case, the fixed target voltage of 1.0 per unit for ULTC transformers also satisfied the required voltage limits without changing the tap positions within the planning time period. However, the tap changers were set to be at the position of -1 based on the load flow results, which meant a relatively higher voltage profile. The AI planner did not suggest any changes to the nominal tap position settings simply because no voltage violation was detected.

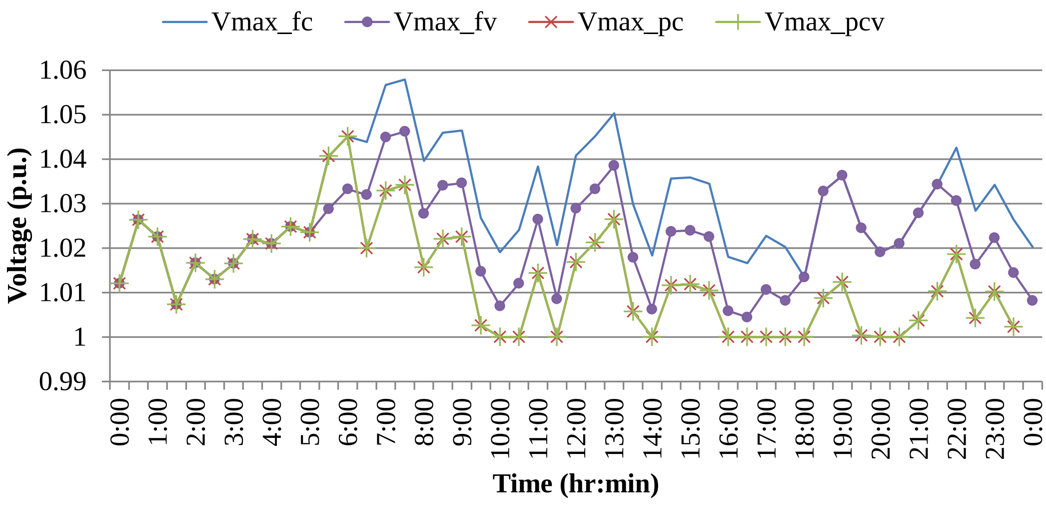
Comparison of case 2a and case 2b

By referring to Table 6-8 and Table 6-9, it can be seen that, for all the studied tap changer control approach, the active losses are less when DGs were operated under the AVR mode compared with the PFC mode. By comparing the conventional fixed target voltage approach in case 2a and case 2b, it can be seen that the AVR control mode for DGs did not incur any control cost while the PFC mode caused a control cost of 0.2. It can be also observed that, regarding the planning approach, the total control cost was 0 (less by 0.4) and the losses were less by 0.313MWh for the AVR mode than the PFC mode.

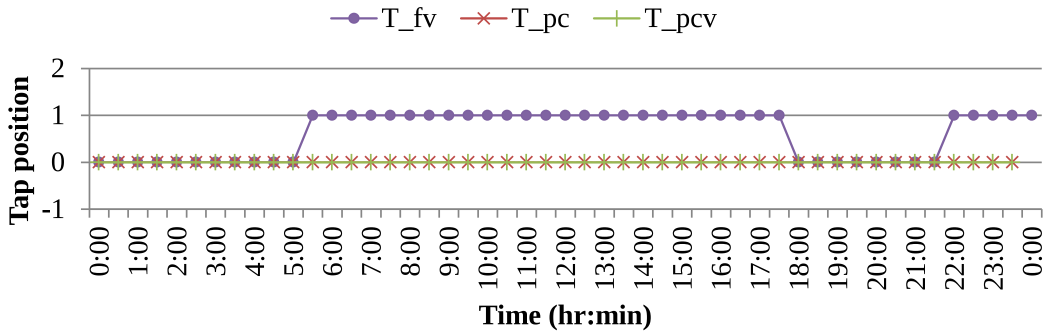
6.3.3 Case 2c: Transformer, DG AVR and MSR

In this case, in order to study the coordination of ULTC transformers and an MSR, it was assumed that the control cost of switching on or off an MSR is lower than the cost of changing the transformer tap positions. That is 0.05 for each switching action of the MSR and 0.1 for an incremental change in transformer tap positions. The two DGs were assumed to be under PFC with a power factor of 0.95 and the MSR was assumed to be placed at node C20, where one of the distribution feeders terminate and a number of loads were supplied from, in order to best compensate the heavily loaded part of the distribution network.

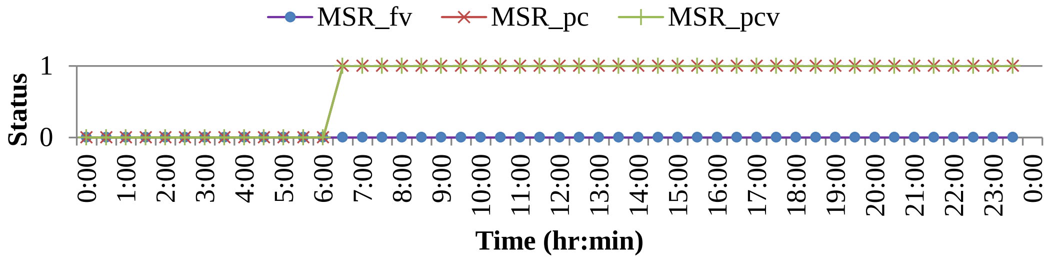
It should be noted that, for the conventional control mode, the MSR was assumed to be under local automatic control that has a high voltage threshold of 1.06 per unit, i.e. the MSR will be switched on if the local voltage is higher than 1.06 per unit. Similar to MSCs, MSRs tend to have a relatively higher voltage threshold setting (or a higher DB setting) than transformers because the switching action of an MSR normally leads to a relatively bigger change in voltage magnitude. The time series profiles of the maximum voltages experienced across the network, tap changer operations and MSR status were depicted in Figure 6-13; the simulation results were summarised in Table 6-10.



(a) Maximum voltages



(b) ULTC transformer tap positions



(c) MSC on/off status

Figure 6-13 Time series profiles of maximum voltage, tap positions, MSR status - case 2c

Table 6-10 Case summary - case 2c

Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs
Nominal tap position	1.057906	0.9995	5	0	0
Planned control	1.045097	0.975147	0	1	0.05
Planned voltages	1.045097	0.975147	0	1	0.05
Conventional control	1.04618	0.989369	0	6	0.6

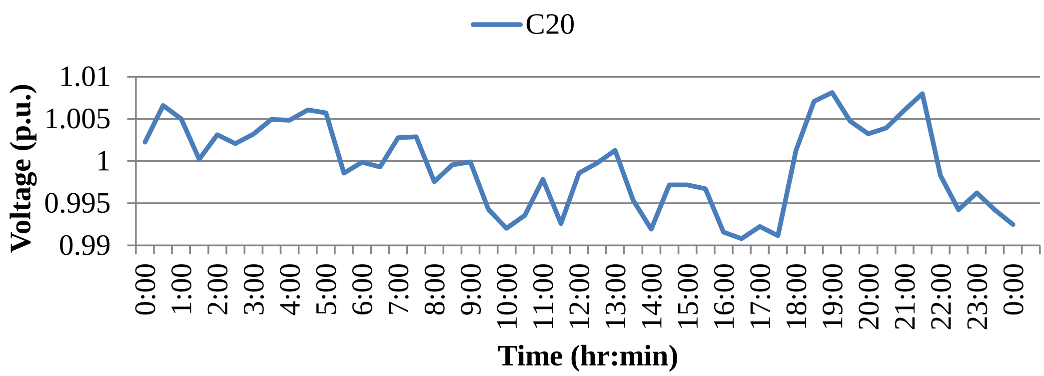


Figure 6-14 Time series profiles of voltage at the MSR-connected node C20 - case 2c

It can be seen from Figure 6-13 and Table 6-10 that the fixed nominal tap position settings resulted in 5 high voltage violations at the time window from 07:00 to 08:00. The conventional methods, i.e. the fixed target voltage for transformer AVC schemes and the local automatic control of the MSR, did not lead to any voltage violations by adjusting tap positions at 05:30, 18:00 and 22:00, leading to a total control cost of 0.6. Owing to the tap changer operations, the highest voltage seen by the MSR during the planning time period was 1.045 per unit, lower than the high voltage threshold of 1.06 per unit, as seen in Figure 6-14. Therefore, no MSR switching action was seen under local control, shown in (c) of Figure 6-13. Instead of using the ULTC transformers, the AI planner scheduled the MSR to be switched on at 06:30 to improve voltage profiles because of its relatively lower control cost. The same results were observed when the planned tap positions' resultant voltages were used. In this case, both planned control settings and resultant target voltages eliminated voltage violations at a much lower cost compared with the conventional control approach.

6.4 Case 3: Summer Scenario (15mins)

In this section, the studied time interval was set to be every 15 minutes instead of 30 minutes to examine whether the proposed methodology is capable of dealing with the rapidly varying nature of demand and generation. The daily time series profiles of demand used in this section were derived from reference [88]; the time series profile of wind power output is shown in Figure 6-15. The summer scenario is evaluated in this section to account for the high variability of renewable resources as well as the local voltage regulation.

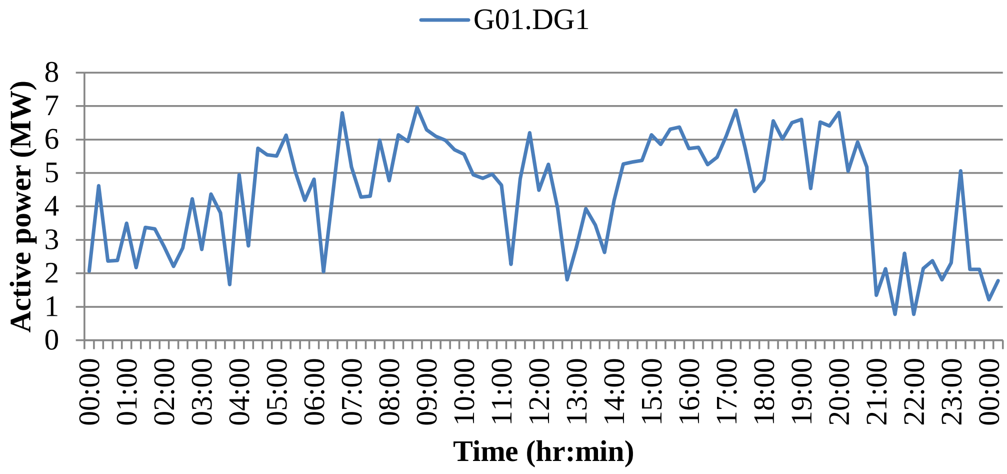
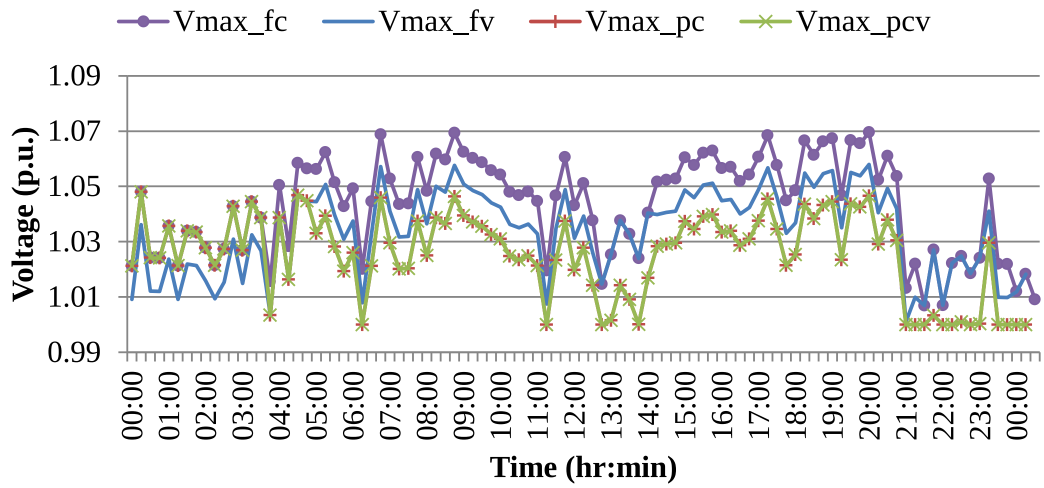


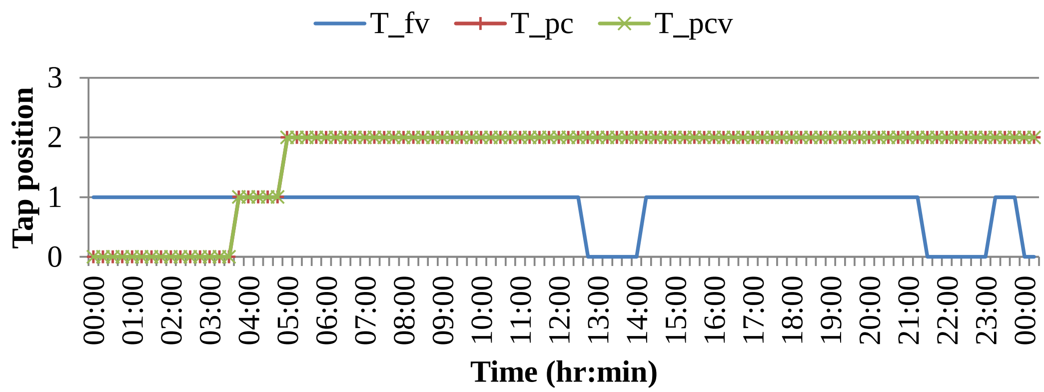
Figure 6-15 Daily time series profile of wind power output every 15 minutes for case 3a

6.4.1 Case 3a: Transformer and DG PFC

In this case, DGs were assumed to be operated under PFC mode with a lagging power factor of 0.95 (case 2a was set up the same as case 1a except that the planning time interval is 15 minutes instead of 30 minutes). The time series profiles of the maximum voltages experienced across the network as well as profiles of tap operations were depicted in Figure 6-16 for the studied control modes of ULTC transformers; the simulation results under these control modes were summarised in Table 6-11.



(a) Maximum voltages



(b) ULTC transformer tap positions

Figure 6-16 Time series profiles of maximum voltage and tap positions - case 3a

Table 6-11 Case summary - case 3a

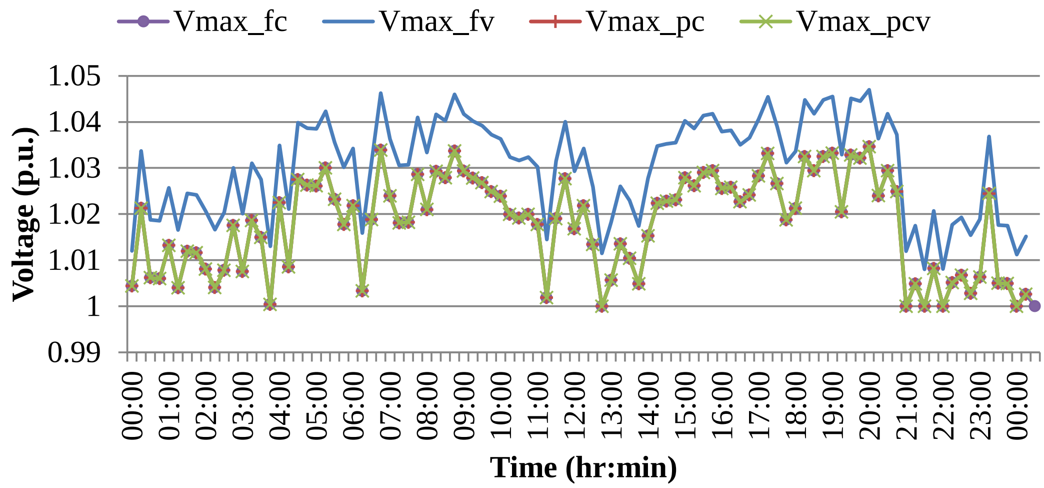
Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Nominal control	1.069517	1	87	0	0	5.65166
Fixed voltages	1.0579	0.989561	26	10	1.0	5.77252
Planned control	1.047991	0.976237	0	4	0.4	5.879305
Planned voltages	1.047991	0.976237	0	4	0.4	5.879235

From the voltage plots in (a) of Figure 6-16 and the content in Table 6-11, it can be seen that the maximum voltages experienced across the network exceeded the upper limit at a wide range of time slots when tap changers were fixed to be at the nominal positions, causing a total number of 87 voltage violations, much more than that of case 2a due to the increased number of time slots and the sharp change in generation between every two consecutive time slots. There were 26 voltage violations when tap changers were operated under the fixed target voltage of 1.0 per unit, leading the tap changers to be at the position of +1 at the start and to change five times throughout the planning period. The resultant control cost is 1.0, four times higher than that of case 2a. The planned tap settings eliminated voltage violations by changing positions at 03:30 and 05:00 with a total control cost of 0.4; the planned tap settings' corresponding resultant voltage led to the same results. Compared with case 2a, planned solutions led tap changers to go through more changes due to the rapid fluctuations in DGs' output. Nonetheless, planned solutions improved voltage profiles at a much cheaper cost than the conventional control approach.

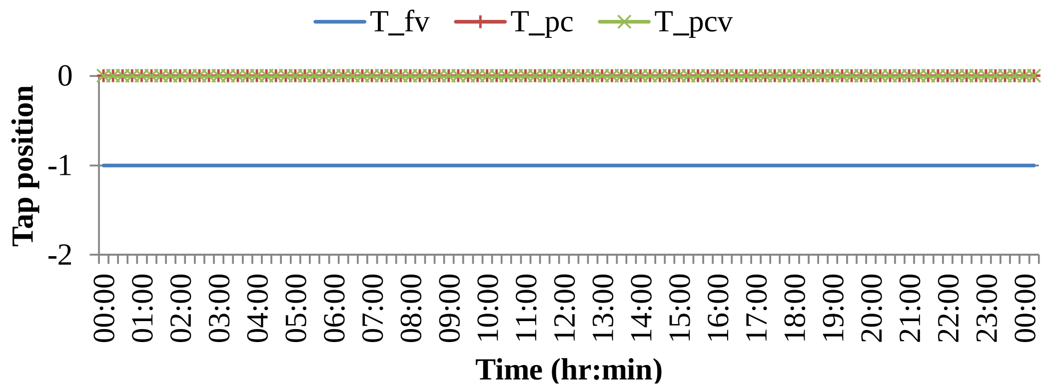
In addition, the calculation time for solving this case was about 7.781 seconds, whilst case 1a took around 4.125 seconds, about 47% quicker than case 2a. Besides, with shorter planning time intervals, more computer hard disk capacity is also required to solve the case because of the increase in the volume of data.

6.4.2 Case 3b: Transformer and DG AVR

DGs were assumed to be operated under AVR control mode (with reactive capability set to be 0.95 lagging and leading) in this case. The time series profiles of the maximum voltages experienced across the network as well as profiles of tap operations were depicted in Figure 6-17 for the studied control modes of ULTC transformers; the simulation results under these control modes were summarised in Table 6-12.



(a) Maximum voltages



(b) ULTC transformer tap positions

Figure 6-17 Time series profiles of maximum voltage and tap positions - case 3b

Table 6-12 Case summary - case 3b

Control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Nominal control	1.034633	0.985769	0	0	0	5.5695825
Fixed voltages	1.046945	0.998219	0	0	0	5.433545
Planned control	1.034633	0.985769	0	0	0	5.56602
Planned voltages	1.034621	0.985769	0	0	0	5.5640775

It can be seen from Table 6-12 that there was no voltage violation for all the studied transformer control methods and no tap changing operation was observed, owing to the reactive support provided by the two DGs. Compared with case 3a when DGs were operated under PFC mode, AVR mode improved the overall voltage profiles without requiring tap-changing operations and resulted in relatively lower losses.

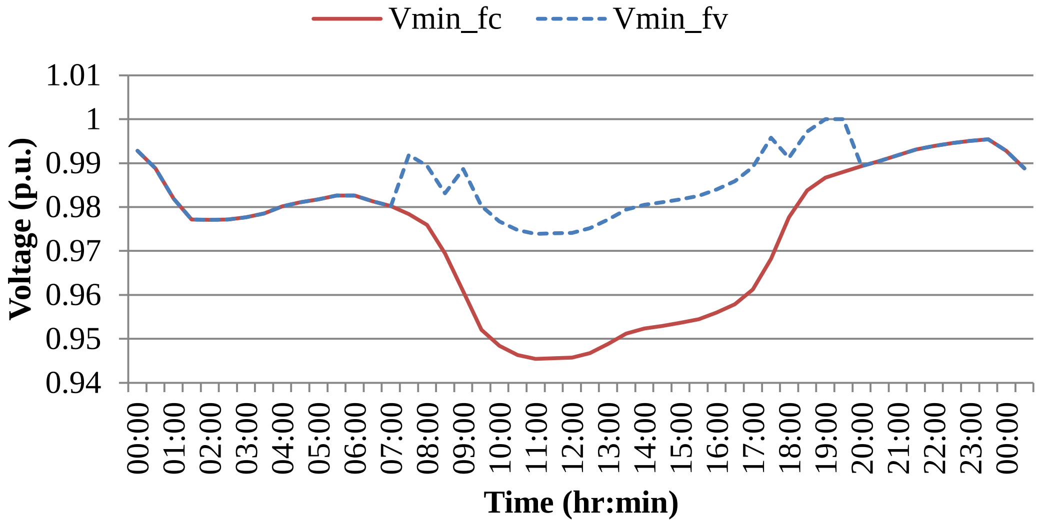
6.5 Case 4: Fail-safe Mode

The concept of fail-safe mode was brought forward in the context of this thesis to deal with the following potential situations: when the AI planner fails to generate any solution in the first instance; when the planned solutions cannot satisfy the requisite voltage limits after re-planning; or when communication failures cause the unavailability of system data such as the status of system components or forecasted demand and generation data. As mentioned in section 5.7, the planner could fail to reach a solution even after re-planning as a result of an incorrectly modelled voltage control problem. That means that no control action can be found to satisfy the required limits due to insufficient control margins or erroneous control sensitivities. For instance, the current tap position given to the planner is already at one of the limits but the planner anticipates that a change to be beyond the limit is required. Another example is that the planner decides that applying the required control actions will violate the other limit due to erroneous sensitivity factors, if the calculated sensitivities are much greater than the actual sensitivities.

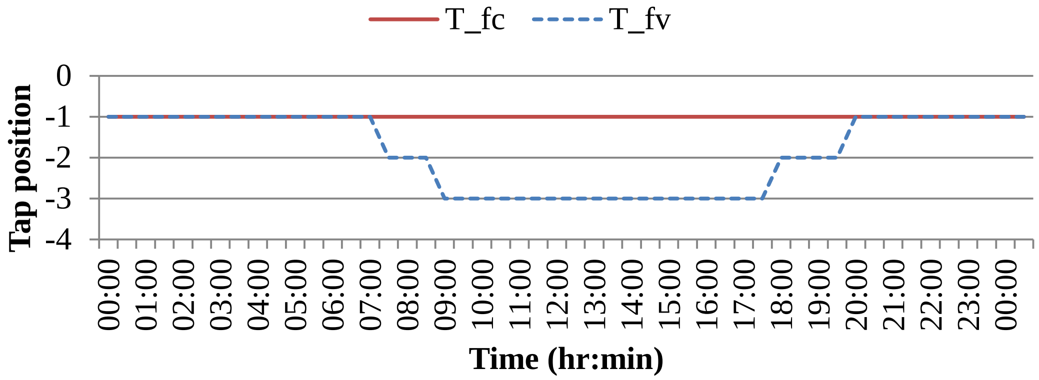
The fail-safe mode should be reasonably capable of providing appropriate control actions that comply with voltage security requirements, concerning the available control equipment, control modes and control schemes. In this thesis, the fail-safe mode essentially refers to the conventional voltage control methods, i.e. fixed target voltage settings for ULTC transformers' AVC schemes, local automatic control for MSCs and DG's available control modes. If both PFC and AVR control modes are possible with DGs, the proposed methodology can examine both options to identify the relatively cost-effective one.

6.5.1 Case 4a: Winter scenario without DGs

Winter scenario (200% loading) was studied in this case assuming that DGs were unable to export any power to the network. Therefore the conventional transformer control approach is regarded as the fail-safe mode. As a comparison, fixed tap position control were also simulated with the tap changer positions fixed at -1 to raise the voltage profiles at the secondary side of the transformer. The results are shown in Figure 6-18 and summarised in Table 6-13.



(a) Minimum voltages



(b) ULTC transformer tap positions

Figure 6-18 Time series profiles of minimum voltage and tap positions - case 4a

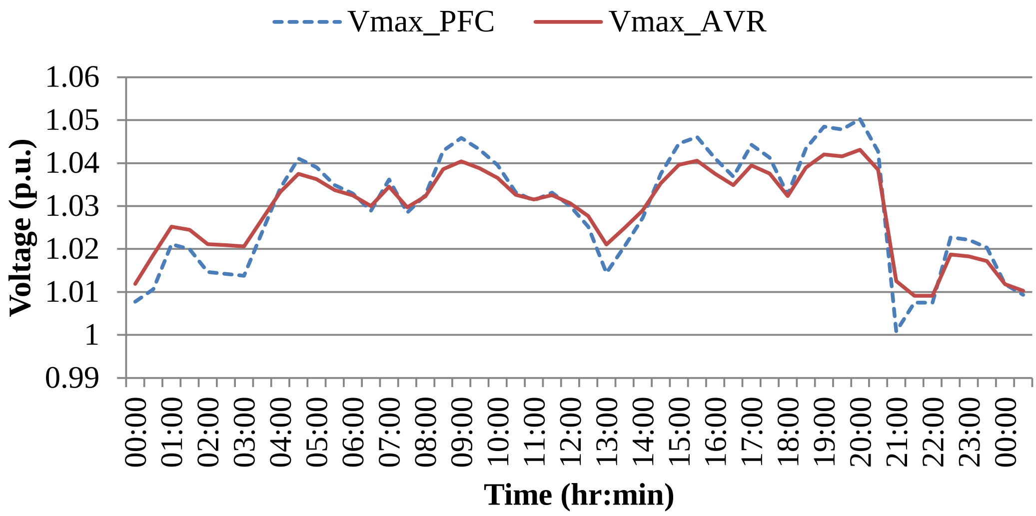
Table 6-13 Case summary – case 4a

Transformer control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
Fixed voltage	1.009065	0.973893	0	8	0.8	2.630628
Fixed tap	1.001257	0.945435	90	0	0	2.7427925

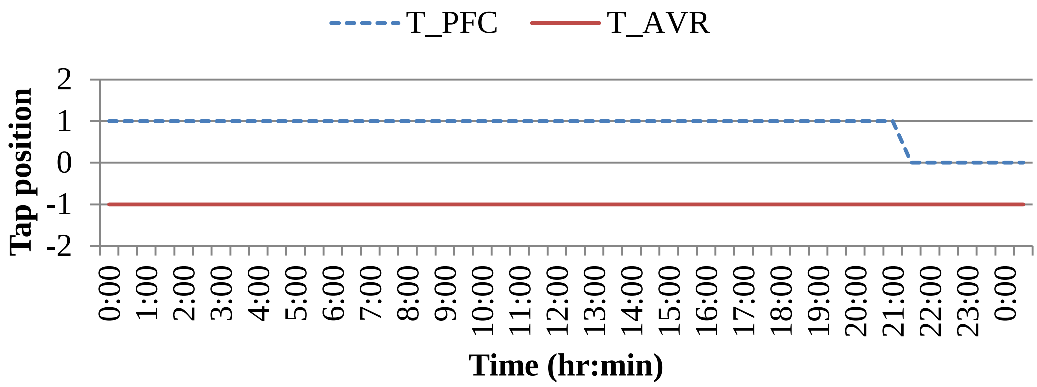
The voltage and tap position plots in Figure 6-18 suggested that when tap changers were fixed at the position of -1, the minimum voltage fell below the lower limit from 10:00 to 13:00. It can also be seen that when tap changers were operated under AVC fixed target, the voltage profiles were within security limits with tap changing actions at 07:00, 09:00, 18:00 and 20:00 respectively. It can also be seen from Table 6-13 that the total losses were relatively lower when the tap changers were operated under fixed target voltage, compared with the fixed tap position setting. On that basis, the failsafe control mode, i.e. the fixed target voltage for transformer AVC schemes, ensured that voltage limits were respected at the control cost of 0.8 with reduced active power losses. .

6.5.2 Case 4b: Summer scenario with DGs

In this case, it was assumed that the loading scale for demand was 0% and the DGs were rated at 6MW with the same output profile as in case 3 and operated under either PFC mode or AVR mode, i.e. two options for the failsafe control mode. The ULTC transformers tap changers were operated with fixed voltage target. The maximum voltage experienced at each time slot and tap changing operations are shown in Figure 6-19 and summarised in Table 6-14.



(c) Maximum voltages



(d) ULTC transformer tap positions

Figure 6-19 Time series profiles of maximum voltage and tap positions - case 4b

Table 6-14 Case summary – case 4b

DG control mode	Vmax (p.u.)	Vmin (p.u.)	No. of violations	No. of changes	Control costs	Losses (MWh)
PFC	1.050261	0.991372	1	2	0.2	4.5253015
AVR	1.043104	0.993147	0	0	0.0	4.2171365

It can be seen from the voltage plot in Figure 6-19 that the time series voltage profile was relatively smoother when DGs were operated under AVR mode, compared with the PFC mode. The maximum voltage with DGs under PFC mode was marginally higher than the upper limit at 20:00 at node G02 where one of the DGs was connected, because of DGs' export of reactive power at the power factor of 0.95.

This implies that AVR control enabled the DGs to better regulate the local voltages than PFC mode. The tap position plot in Figure 6-19 suggested that no tap changing operation was observed with DGs under AVR control mode while one step change was observed at 21:30 when DGs were operated under PFC mode. In the meanwhile, the summary in Table 6-14 suggested that the total losses when DGs were under AVR mode were less than PFC mode, by 0.308MWh. Therefore, AVR control mode for DGs is more preferred than the PFC mode.

6.6 Case 5: External Factors of Planning Studies

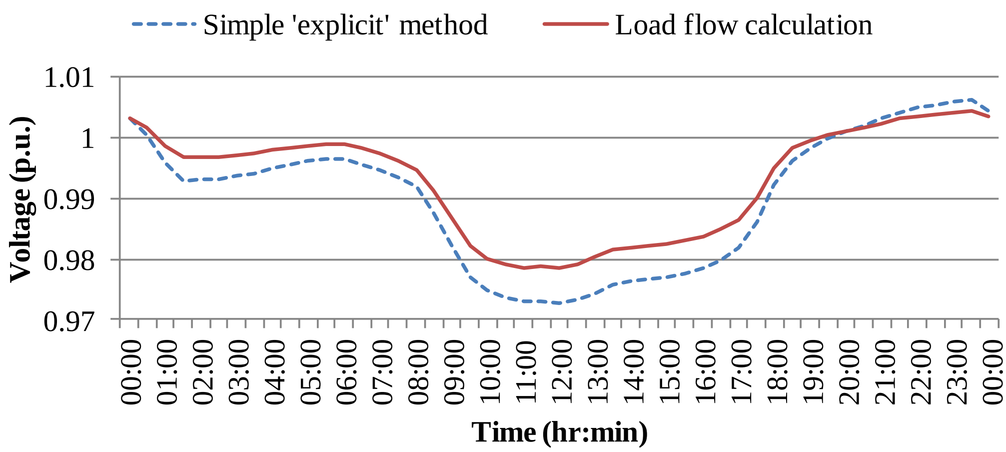
Case studies in this section were carried out to evaluate the factors that may have an impact on the accuracy and speed of the proposed methodology.

6.6.1 Case 5a: Computation of Time Series Voltages

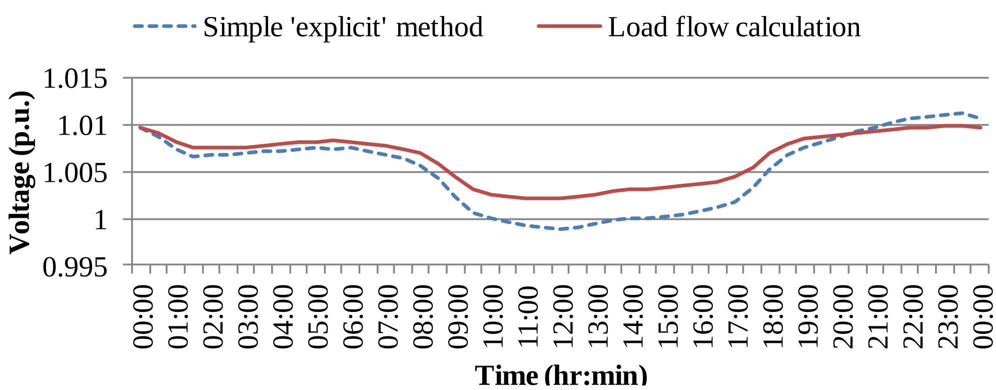
Given forecasted time series demand and generation data for an electrical network, there are two primary methods to predict the corresponding voltage profiles. One method is to obtain the time series voltages by executing the N-R load flow algorithm under specific loading and generation conditions at each given time slot; the other is to use the sensitivity-based calculation method introduced in section 4.1.5 to estimate voltages for each time slot on the basis of the initial load flow solution, the changes in demand and generation every two consecutive time slots and the sensitivity of voltage change with respect to changes in active and reactive power, on the basis of equation (4-56). The first method provides a more accurate estimation of actual voltages by repeated iterative calculation at all time slots; thus it requires relatively heavier computational effort and takes a relatively longer time to solve.

The simple sensitivity-based method, however, is computationally easier because only an initial load flow solution is required as the starting point before voltages for the subsequent time slots are calculated based on the previous solution and the changes in demand and generation between two consecutive time slots along with the sensitivities of these changes. The limitation of this method is that it provides only a linearised estimation of time-series voltages based on the knowledge of the previous time slot and the accuracy of the calculated results is highly sensitive to the magnitude of the change of network conditions between every two consecutive time slots. Due to the nonlinearity of electrical systems, the faster sensitivity-based approximation only suffices to estimate voltages when the changes between consecutive time slots are reasonably small. Therefore, in the previous studies, the time series voltage profiles that were used in the planning studies were obtained through iterative load flow calculations rather than direct calculations using the simple sensitivity-based method.

In this section, two case studies were carried out in order to demonstrate the difference in the time-series voltages calculated using the two methods. To primarily examine the magnitude of demand change, the two DGs with wind power profile were set to be producing 40% of the normal output with no reactive capability. In scenario (i) and (ii), the loading scale of demand was assumed to be 150% and 50% respectively; the former has arelatively larger change between adjacent intervals while the latter has a smaller change. The time series voltage profiles calculated by the two methods were depicted in Figure 6-20 and the simulation results were summarised in Table 6-15 in terms of error and computation time.



(a) Time series voltage at node D02 - 150% loading condition



(b) Time series voltage at node D02 - 50% loading condition

Figure 6-20 Estimated time series voltage profile at node D02 – case 5a

Table 6-15 Summary of time-series voltage calculation results – case 5a

Scenario	**Scaling factor (%)**		**Error range (%)**	**Calculation time (s)**	
	Demand	Generation		Load flow algorithm	Sensitivity-based method
i	150	40	-0.5720, 0.0210	0.375	0.265
ii	50	40	-0.0977, 0.0581	0.375	0.266

It can be seen from the plots in (a) and (b) of Figure 6-20 that the difference between the two voltage curves obtained using the two methods is relatively smaller when the loading scale was lower, i.e. when the changes of loads was smaller between two adjacent time slots. According to Table 6-15, the biggest error (assuming that the load flow algorithm's result is accurate) was 0.572% and 0.0977% respectively for the loading condition of 150% and 50%; voltage error of the lower loading condition is significantly lower than that of the higher condition. Therefore, the smaller the magnitude of change at each time interval, the more accurate the sensitivity-based method becomes. It can also be seen from Table 6-15 that the time it took for the load flow algorithm to solve for voltage profiles was slightly longer than that of the sensitivity-based method, with a very minor difference of 0.109 seconds (about 29.33% of the total calculation time of 0.375 second).

In view of the accuracy and efficiency of IPSA+'s load flow algorithm, it was used for all the case studies presented in this thesis to identify the system states around which sensitivity matrices are calculated, to obtain the time series voltage profiles as descriptions of the voltage problem for the planner to deal with and to test and validate the planned solutions. The studies on the planning approach and the conventional approaches assume that system states based on load flow calculations are representative of the 'real electrical system'.

6.7 Summary

This chapter has introduced the studied network model and explained the simulation procedures, followed by a range of case studies to verify the effectiveness and robustness of the proposed methodology as well as the 'failsafe' mode. The simulation results of the case studies have been discussed and conclusions have been drawn.

7. Conclusions and Future Work

This chapter concludes the thesis and provides suggestions for future work.

7.1 Conclusions

The thesis has provided an in-depth overview of the operation of power systems with particular discussions on distribution networks in terms of the existing voltage management practice. It has discussed a wide range of topics related to the core of the research work, the operational management of voltage in distribution networks. The following subsections are a brief summary of the main points in the thesis and the concluding marks about the research work.

7.1.1 Summary of the Thesis Background

The quality of supply is a key consideration for SOs, TSOs and DNOs in the daily operation of modern power systems; voltage quality, in particular, is a paramount measure of the power quality at the electricity user's side. In transmission systems, voltage control is typically achieved using a range of equipment including FACTS devices, ULTC transformers, MSCs and the terminal voltage references for AVRs of synchronous generators [127]. In the GB distribution networks, the control of voltage is normally performed by AVC schemes that regulate ULTC transformers, and in a few cases, by MSCs. However, the automatic control schemes only reach as low as 33/11kV and the voltage performance at networks below 11kV is rarely monitored or controlled [52]. Voltage profiles at distribution networks are normally subject to varying demand and generation, equipment maintenance and other unanticipated events such as loss of equipment. Since the UK government urged an increasing use of renewable energy for supplying demand, the number of generators using renewable resources has been growing significantly in both transmission systems and distribution networks in the past decade [11]. This has also increased the degree of complexity of control of voltages in distribution networks. Electricity demand also influences voltage profiles through the consumption of active and reactive power. Typically, energy users are broadly made up of domestic and nondomestic customers; electricity consumers in the UK can also be categorised as unrestricted users and economy seven users that can take advantage of the Economy Seven tariff, which offers a standard tariff for using electricity during daytime and a relatively cheaper tariff for energy consumption at night time [297]. The presence of different types of energy customers makes electricity demand diverse and stochastic. Demand is typically characterised by power factor, which indicates the relation between active power and reactive power. A lagging power factor means absorption of reactive power; the lower the power factor, the more reactive power is consumed. Power factors that are close to unity is typically preferred by SOs at large electricity consumers' sites considering that reactive power cannot be transmitted over long distances [127].

Voltage control problems can be addressed from a real-time point of view, or a control dispatch perspective. Real-time control requires fast computation and quick results while dispatching voltage control equipment generally is considered as one of the operational planning activities. In the state-of-the-art literatures, voltage control has been addressed as an optimal RPD problem under the OPF context, which is typically treated as an NLMIP. Conventional optimisation techniques have long been proposed for solving this nonlinear dispatch problem and intelligent systems have also been developed based on optimisation techniques for reaching the optimal schedule. The optimisation results of most optimisation techniques, whether conventional or AI-oriented, normally depend on an appropriate initialisation of the studied population and the optimisation process is highly computationally expensive. Above all, most of the publications that looked into voltage control problems from an operational planning perspective and only dealt with voltage control problems at 'snapshots' regardless of the time-varying nature of demand and generation. Only a small number of publications have approached the voltage control problem by looking into the time intervals across a certain time period. Some of these publications were based on optimisation techniques with constraints on the changes in system control variables between time slots [270][273][277][279]; some used fuzzy inference methods with an overall time period divided into five intervals using fuzzy rules [231]; some combined a numerical approach with a heuristic method [271][276] with clear definitions on load trend based on changes across time intervals; some work looked at voltage control problems at different hierarchies and used the two-stage approach to break down the entire operational planning time period into a number of intervals [272][280]. All of these methods depend either on the appropriate division of given load curves or on the definition of increasing or decreasing load trend. However, the observations on load patterns are subject to the diversity of demand and may result in confusions over when to divide load curves. Besides, fluctuations in the growing DGs' penetration should not be overlooked; similar divisions of DG curves may be necessary, which will significantly increase the complexity of the problem.

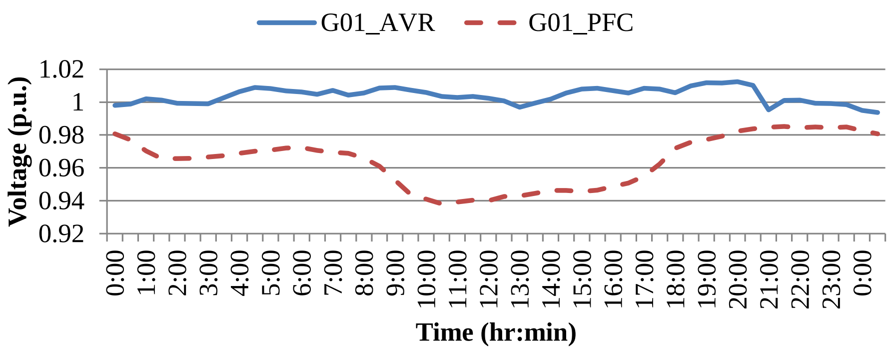
In summary, most of these methods that are based on time intervals only had a single objective function, either to minimise the total active losses or to improve voltage security levels for each time interval rather than the entire time period. The majority of the methods involve complicated iterative algorithms and as yet few have been deployed by power utilities to tackle voltage control or reactive power control problems on actual power systems. Above all, few looked into both voltage security and the control costs caused by voltage control actions, e.g. the wear-and-tear due to switching operations. The proposed methodology is thus developed in this research work in order to overcome these limitations, as introduced in the subsequent section.

7.1.2 Concluding Statements on the Methodology and Case Studies

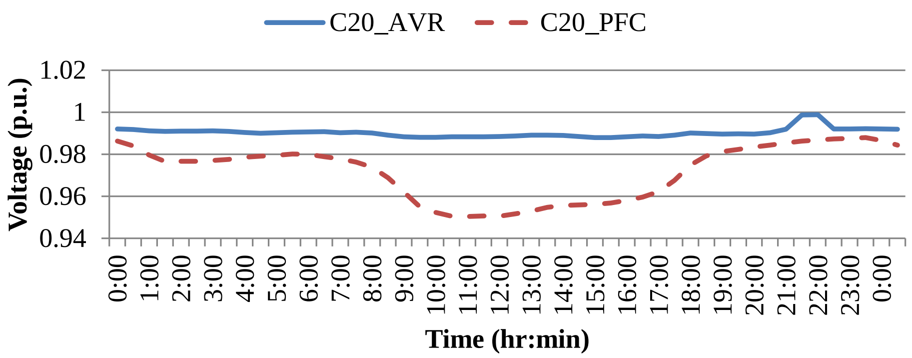
This thesis discusses voltage control problems at distribution networks from an operational planning perspective and introduced a new methodology that integrates power system sensitivity analysis with an artificial intelligence planning tool to better schedule control actions to maintain a desired level of voltage security while reducing the wear and tear on voltage control equipment by minimising the total number of control actions across the planning time period. Specifically, a strategic voltage control methodology was developed to schedule control settings or voltage targets for ULTC transformers and status settings for MSCs for different network models under a variety of loading conditions and DG profiles.

A range of case studies were carried out on a distribution network model to examine the proposed methodology in terms of its capability to choose the appropriate control actions to deal with voltage violations. The available control equipment in the distribution network included two substation ULTC transformers, an MSC and two DGs. Two primary scenarios were evaluated: low voltage scenario under winter peak demand with normal DG output (rather than low output, to allow DGs to possess some capacity for reactive power production) and high voltage scenario under summer minimum demand with high DG output. In each case, transformers' nominal tap position settings were used to obtain an initial time series 'picture' of the voltage control problem, used by the AI planner as inputs to generate solutions regarding control settings. For each scenario, the planned control approach was compared with the conventional control approach with regard to transformer tap position settings and MSC status settings, while DGs were operated under either PFC mode or AVR mode. The conventional control approach refers to the fixed 1.0 per unit target voltage setting for ULTC transformers and automatic switching of MSCs.

In case 1 and case 2, a winter scenario and a summer scenario have been examined on half-an-hour time intervals respectively, taking into account the control of transformer tap changers and an MSC as well as the control of DGs. The objective of these two cases is to evaluate the capability of the proposed methodology to deal with high voltage and low voltage violations. By comparing the conventional control approach and the planning approach for the transformers and the MSC under the two case scenarios, it was concluded that the planning approach ensured that voltage profiles stay within the requisite limits at a relatively cheaper cost, whether the DGs were operated under AVR or PFC mode. By comparing the operation mode of DGs when the transformer tap changers were operated under the conventional fixed voltage targets, it was observed that, the time series profiles of the maximum and the minimum voltages were relatively smoother, i.e. closer to 1.0 per unit, when DGs were under AVR control, especially at the nodes where DGs were directly connected, and most importantly, the transformer tap changers had less control operations, i.e. less control costs. The system losses in MWh were also relatively smaller when DGs were operated under AVR control mode than when under PFC mode. This is because that the AVR control mode of the generator ensured a relatively flatter voltage curve throughout the planning period with the voltages being relatively closer to 1 per unit, compared with the PFC mode whose voltage profiles were more fluctuating and lower than 1 per unit, as shown in (a) of Figure 7-1. The same observations can be made for the voltage profiles at the load terminals, as shown in (b) of Figure 7-1. As a result, the flow of reactive power was reduced for the AVR control mode, and the current flowing in the distribution network was smaller in magnitude and thereby the total system losses were less. This made the AVR control mode more favourable over the PFC mode, especially when DGs were able to generate a sufficient amount of power.



(a) Voltage at the generator terminal G01



(b) Voltage at the load terminal C20

Figure 7-1 Time series profiles of voltage at a generator node and a load node - case 1a &1b

In case 3, the summer scenario has been further examined with time intervals set to be every 15 minutes rather than 30 minutes and the two control modes of DGs were studied. The purpose of this scenario is to examine how the planned solutions are affected by the volatility of DGs' output. It was observed from the simulation results that, regarding the control of the transformer tap changers, when the DGs were under the PFC mode, the planned control approach led to fewer control actions than the conventional control approach. In the meanwhile, the AVR mode for DGs ensured that there was no tap changing operation whether transformer tap changers were regulated using the planned approach or the conventional approach. Similar to the conclusion drawn from case 1 and case 2, the total losses in MWh were relatively less for AVR mode than for PFC mode, for each control mode of the ULTC transformers. Therefore, it can be concluded that it was more favourable to control transformer tap changers with the DGS operated under AVR control mode than PFC mode.

To deal with the possibilities of failures of planning, resulting from the loss of communication or a wrongly modelled system, a concept of failsafe mode has been introduced, referring to the conventional control approach of transformer tap changers, automatic local control of MSCs and available control modes of DGs. In case 4, two scenarios had been looked into to demonstrate the failsafe mode: winter scenario with no output from DGs and summer scenario with no load. The failsafe mode regarding the control of transformer tap changers alone has been examined in the winter maximum demand scenario in case 4a, by assuming that DGs were unable to export any power. The simulation results suggested that the conventional fixed target control approach managed to ensure that voltage profiles stay within the requisite limits via automatic tap-changing operations at the expense of less system losses. In case 4b, the operation modes of DGs were examined in the summer no load scenario, assuming that the transformer tap changers were under the conventional fixed target control. The simulation results indicated that AVR control mode for DGs resulted in less tap-changing operations compared with PFC mode and less system losses.

Finally, given a time series of forecast demands and generation profiles, the planner requires an estimate of future voltages. This could be achieved by successively solving an AC load flow for each successive time step or, alternatively, by simply using linear sensitivities (as described in section 4.1.5) calculated at the initial time step in order to estimate voltages at subsequent time steps. Specifically, the sensitivity-based method estimates voltages for each time slot based on the changes in demand and generation every two consecutive time slots and the voltages of the previous time slot; the estimation depends on the solved load flow solution at the first time slot under the initial system condition. It is anticipated that the N-R AC load flow algorithm provides relatively more accurate estimation by repeated load flow iterations while the sensitivity-based method assumes a linear system and is less computationally intensive but also less accurate. The purpose of case 5 is to compare these two approaches. Two loading scales (150% and 50%) were studied with DGs exporting 40% of the normal MW time series profile. The simulation results showed that, as anticipated, the error resulting from the sensitivity-based method was relatively bigger when the loading scale was higher. This is because that the changes between every two consecutive time intervals were bigger at a higher loading scale. It was also observed that the N-R algorithm took marginally longer time to calculate the time series voltage profiles compared with the sensitivity-based method. Therefore, the simulation results justified the reasons for using the N-R load flow algorithm for the planning studies. Above all, the N-R AC load flow algorithm is also very fast to solve to obtain the time series voltage profiles across the planning time period.

The primary finding from the case studies in chapter 9 is that, the planning approach ensured that changes in control actions were made only at the time slots where necessary and that the relatively cheaper option is used out of the available control actions. However, a potential limitation of the proposed methodology is the inherent difference between the linear AI planner and non-linear power systems. The linearisation of nonlinear problems is typically effective when the change from a given condition to another condition is relatively small. This means that the proposed methodology can provide excellent results when the changes in voltage profiles between adjacent time slots are relatively small but may not generate appropriate planned results if the change is relatively big in its magnitude. This limitation can be overcome by dividing the planning time intervals into shorter intervals to ensure that the changes over time are small enough for the AI planner to deal with.

In brief, the following conclusions can be drawn:

1) The proposed methodology was proven to be more effective than conventional voltage control methods by maintaining satisfactory voltage profiles and reducing control costs.
2) Its decision making capability can significantly lessen the present heavy dependency on engineering experience;
3) Instead of controlling voltages at snapshots, this work considers the time varying nature of demand and generation as well as their effect on voltage profiles, examines voltage profiles across a defined planning time period and schedules control actions on the basis of voltage sensitivity factors;
4) The voltage limits of the planner can be adjusted to allow for different satisfactory levels depending upon the requirements of networks and operators' preference;
5) A fail-safe mode was incorporated into the methodology so that local voltage control methods can always be reverted to if any failure occurs in the final planning stage or any loss of data communication.

In particular, the failsafe mode was incorporated in case of a failure in generating a plan. The presence of this mode is to ensure that users can always get a plan regardless of the performance of the AI planner and it refers to local equipment control such as a certain setting of tap positions for transformers and a reference voltage for the generators with AVRs. The execution of the failsafe mode in practice may require automatic or manual settings for the equipment and some communication between the control room and the equipment operators (such as wind farm controllers) may be necessary.

The proposed methodology works successfully for observable distribution networks with available day-ahead forecasts of demand and generation. Although at present few distribution networks are fully observable and most DNOs do not have appropriate forecasts, simple and reasonably accurate characterisations of demand and generation and their forecasts as well as an increase in network monitoring are, at time of writing, being addressed in a number of LCNF projects being undertaken in the UK, such as "Flexible Networks for a Low Carbon Future" by SPEN and "New Thames Valley Vision: From data to decisions" by Southern Electric Power Distribution [30]. In addition, forecast of generation has been especially emphasised by the SO in the external incentive plan [80]. On that basis, it is expected that more available measurements will greatly enhance the quality of state estimation results for distribution network analysis; DG owners will be motivated to improve their generation forecasts. Hence, more accurately predicted demand and generation profiles that are anticipated to become available will serve well for the voltage planning problem addressed in this thesis. The robustness of the planning approach against forecast errors is further discussed in the following section.

The planning process for 24 hours in the case studies conducted in this chapter took around 7 seconds to reach final results and hence is much quicker than most of the optimisation algorithms including OPF. This AI planning tool interfaced with the power system analysis software is a simple yet effective solution to most DNOs for coping with the variable demand and generation whilst maximising assets life expectancy by reducing the number of operations.

Above all, network operators will find this planning approach feasible to apply to their existing automated distribution systems and effective to use when it comes to power network operational planning since system security and control costs are both considered in the proposed method. Another advantage is that the planned solutions are easy for operators to interpret and different solutions may be obtained by defining the voltage control problem differently in terms of the maximum and minimum limits.

7.2 Discussions on Planning

7.2.1 Number of Monitored Nodes

In the studied cases presented in chapter 6, a total of 4 nodes (2 nodes that experienced the highest voltage and 2 nodes that had the lowest voltage) were selected to be monitored based on the load flow results at the initial time slot, which was adequate for the voltage control problems, because the studied network is a relatively localised part of a complicated electrical system. A large-scale network will need to have the number of monitored nodes increased to such a level that each of the interconnected areas are adequately represented, to reduce the possibility of any un-monitored node having the lowest voltage at any time slot. However, the increased number of monitored nodes will inevitably require heavier computational effort and potentially more communication infrastructures in practice if the existing measuring devices do not cover the studied nodes or the state estimation techniques cannot provide an accurate 'picture' of the system.

7.2.2 The Philosophy of Planning

Planning control actions and target voltages will enable operators to look ahead of real-time into a certain time period such as one day and schedule control actions in such a manner that changes in control settings only occur when necessary by an appropriate amount whilst respecting the requisite voltage limits. One of the advantages of planning is that unnecessary control operations can be avoided. For instance, with the planning approach, tap changers of transformers are operated under AVC schemes with varying target voltages that are derived from planned tap operations, whilst the fixed target voltage setting for the transformer AVC schemes normally leads to more frequent tap-changing operations due to the time-varying nature of demand and generation. The proposed approach has an objective function that overlooks the total number of control actions across the planning time period by making sure that the required voltage limits are satisfied and the control limits are respected.

In comparison, conventional optimisation approach only deals with each time slot independently when the time arrives. That is, a conventional optimisation approach solves reactive power dispatch problems independent of the changes between two consecutive time slots. Therefore the solutions to an optimisation problem at the previous time slot may be quite 'far-away' from the new solution at the next time slot, i.e. the resultant voltage step change may be big. The volatility of demand and generation profiles overtime also increases the likelihood of big voltage changes between two consecutive time slots, which may not be compliant with system requirements, depending on the scale of the intervals. Specifically, in GB power systems, the SQSS states that, for substations supplying users at any voltage level, the voltage step change following operational switching actions at intervals more than 10 minutes should not exceed ±3%, as depicted in Figure 7-2 [298]. Operational switching includes the switching actions that are a regular practice including manual and automatic actions, such as the tap changing operation of ULTC transformers and switching actions of MSCs or MSRs. Voltage step changes are limited to reduce voltage fluctuations experienced by electricity users that may cause damage to electric appliances. With a planning approach, such a large step change can be avoided in that control actions can start to go through incremental changes several time slots prior to the final solution by looking across a number of time slots.

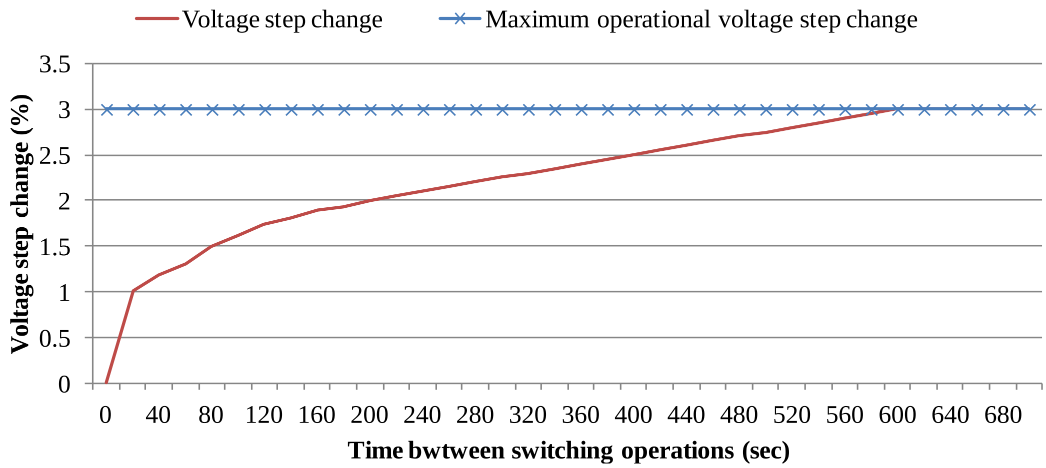


Figure 7-2 Maximum voltage step change permitted for operational switching actions (adapted from [298])

7.2.3 Errors in Planned Solutions

The accuracy of planned solutions is largely dependent on the accuracy of the available forecast of demand and generation as well as the operating condition of the studied network. The timing and magnitude of the predicted profiles are subject to forecast error, which might result in a planned solution that does not comply with the requisite limits. For instance, if a given time series of DG output occurs earlier than anticipated or later, the timing of the worst voltage condition will in turn occur earlier or later. If the forecasted demand or generation is erroneous in terms of the magnitude, predicted voltage conditions will not be accurate, i.e. estimated voltages might be too high or too low. When the actual voltages are 'worse' than predicted (i.e. exceeding the upper or lower limits), more control actions would be required than those initially planned based on the erroneous forecasts; when the actual voltages are 'better' (i.e. the predicted voltage conditions violated the required limits whilst the actual voltages did not), the planned solution may have involved more control actions than necessary. Other network-related factors that could potentially lead the planner to provide erroneous solutions involve changes in network conditions such as fault outages or the closing operation of certain NOPs. Considering that such changes to the network will result in a different set of sensitivity factors, re-planning is also required to update the solutions.

If monitoring devices and 'pseudo-measurements' are available, it is possible to have the knowledge of voltage violations at the studied network. Re-planning will be required, given the most up-to-date forecast of demand and generation as well as network condition, to rectify the originally planned solutions, if any non-compliance of voltage limits is observed. A fault outage that entails loss of supply to customers is likely to be communicated to network operators, in which case re-planning can be carried out once the location of the outage is identified. As for DGs' output, the accuracy of forecast tends to be improved as time gets closer to the real-time since the knowledge of weather is normally more accurate. Therefore, the planned solutions may be updated as the forecast gets revised over time.

When the AI planner's initial solutions are unable to maintain voltages within the requisite limits at certain time intervals, re-planning can be done for the entire predefined time period. It is also possible to only re-apply the AI planner for the particular time duration when voltage profiles are outside the limits. This will reduce the computational effort incurred during the planning process. However, re-planning of part of the entire time period might result in solutions that are inconsistent with those that are already well planned, i.e. the reserved initial planned solutions for the time slots when voltages are within limits. Therefore, the partial re-planning's solutions need to be combined with the initial planned solutions for evaluating the overall quality of the new plan.

7.3 Recommendations for Future Work

Based on what has been achieved in this research work, the following recommendations are outlined for potential extension of the existing work for future applications.

7.3.1 Planning Time Period and Intervals

As mentioned in chapter 8, the planning time period is indefinite and may be defined according to how frequently users wish to update the planned solutions. For instance, the planning process could be performed every six hours ahead of real time when more accurate forecasts become available. The planning time interval may also be set to hourly or quarterly, depending on users' preferences. A shorter time interval indicates more number of time steps and longer processing time and vice versa. The increase in the number of time steps may not necessarily indicate an improvement in the quality of the plan because the planned results are more dependent on the size of voltage changes over time. Voltage profiles in distribution networks are subject to the volatility of DGs, in which case, voltage changes between shorter time intervals may be relatively smaller than longer intervals. Considering that the AI planner requires the control effect, i.e. voltage sensitivities, at each time interval, more time steps will require more sensitivity input. If these sensitivities were to be recalculated every certain time intervals, this would have increased the computational effort in the planning process but with a more detailed representation of the voltage profiles and potentially improved planning quality.

7.3.2 Safety Margin in Planning

It has been mentioned in this chapter that there is a possibility that planned solutions are erroneous. Whilst re-planning is an option as a remedy to the existing solutions, having a 'narrower' range of voltage limits for the original planning problem (i.e. prior to any knowledge of errors) can potentially help to ensure that voltage limits are respected if the actual voltage conditions were to be worse than anticipated. However, the stringent voltage constraints may lead to more frequent control actions, i.e. extra control costs. Therefore, the settings of voltage limits will need to be chosen with attention paid to the trade-off between voltage security and operational costs.

7.3.3 Application to Transmission Systems

The proposed methodology can be extended to deal with voltage control problems in transmission systems. For the GB transmission system, voltage control is currently achieved by strategically regulating a wide range of control equipment such as synchronous generators, transformer tap changers, MSCs, MSRs and other reactive compensators such as SVCs to meet specific voltage targets at crucial locations such as grid supply points and industrial load centres. However, the existing coordinating voltage control strategy used in the GB transmission systems such as the Automatic Reactive Switching (ARS) scheme (as introduced in section 3.3.2) only focuses mainly on voltage security and MVAr reserves but pays attention to the wear-and-tear on equipment by the required control operations only to the extent that the breakers that are opened and closed to connect or disconnect banks of capacitances are cycled. Therefore, some computational aid will be helpful to the SO in terms of the reduction of control cost. The meshed configuration of transmission systems poses a complex and challenging voltage control problem in that voltages at various locations are sensitive to many control actions (not only the local control operations but also the neighbouring ones), generation and demand interactions. Considering that voltage control is a relatively localised problem, it may be necessary to set up the planning problem to deal with voltages for a limited number of substations that are electrically close. It is important not to exhaust the planning tool by considering too many substations because it may become computationally difficult to reach a converged solution.

The AI planning approach was used for planning voltage control actions throughout this thesis; it can also be used to deal with other problems that are concerned about coordination of available resources across a certain time period. Such problems include generation dispatch, unit commitment, maintenance scheduling and equipment outages.

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Appendix A. Supplementary Data

A.1 Distribution Network Data

Sbase = 10MVA

Table A-1 Line data in per unit

From Busbar	To Busbar	Type	Resistance (pu)	Reactance (pu)	Standard Rating (MVA)	Standard Send (kA)
D02	A01	C	0.017385	0.008455	7.621	0.4
A10	A11	C	0.001058	0.000288	5.144	0.27
A11	A13	C	0.001322	0.00036	5.144	0.27
A11	A12	C	0.003437	0.000935	5.144	0.27
A05	A06	C	0.000068	0.000033	7.621	0.4
A06	A07	C	0.001612	0.000784	5.906	0.31
A07	A08	C	0.02993	0.008139	5.144	0.27
A07	A09	C	0.000664	0.000323	7.621	0.4
A01	A14	C	0.000097	0.000052	7.431	0.39
A14	A10	C	0.002538	0.00069	5.144	0.27
A14	A02	C	0.00519	0.002782	7.431	0.39
A02	A03	C	0.000339	0.000165	7.621	0.4
A03	A04	C	0.001707	0.00083	7.621	0.4
A04	A05	C	0.002209	0.001074	7.621	0.4
D01	B01	C	0.014864	0.007229	7.621	0.4
B01	B02	C	0.002293	0.001229	7.431	0.39
B02	B03	C	0.002115	0.000575	5.144	0.27
B02	B04	C	0.001491	0.000725	7.621	0.4
B05	B06	C	0.001016	0.000494	7.621	0.4
B06	B07	C	0.000068	0.000033	7.621	0.4
B06	B08	C	0.000813	0.000395	7.621	0.4
B04	B05	C	0.000745	0.000362	7.621	0.4
C08	C01	C	0.007375	0.001677	3.525	0.185
C20	C19	C	0.00456	0.001237	4.954	0.26
C03	C02	C	0.001348	0.000367	5.144	0.27
C06	C03	C	0.002598	0.000946	4.858	0.255
C06	C05	C	0.004428	0.001201	4.954	0.26
C04	C06	C	0.000848	0.00023	4.954	0.26
C04	C07	C	0.002033	0.000989	7.621	0.4
C08	C04	C	0.001206	0.00055	7.431	0.39
C09	C08	C	0.001231	0.00066	7.431	0.39

C10	C09	C	0.004204	0.003207	10.098	0.53
C18	C10	C	0.003645	0.001773	7.431	0.39
C11	A04	C	0.000108	0.000053	7.431	0.39
C12	C11	C	0.010153	0.002754	4.954	0.26
C13	C12	C	0.004759	0.001294	5.144	0.27
C14	C13	C	0.012084	0.001934	2.763	0.145
C15	C14	C	0.00119	0.000326	5.144	0.27
C16	C15	C	0.019209	0.003074	2.763	0.145
C17	C16	C	0.031459	0.007153	3.525	0.185
C18	C17	C	0.008813	0.002509	4.763	0.25
C20	C18	C	0.005921	0.00288	7.431	0.39
D02	C20	C	0.003657	0.001904	5.906	0.31
S01	D01	T	0	0.1	16	
S01	D02	T	0	0.1	16	
S01	D03	T	0	0.1	12	
D03	D01	C	0.0001	0.0001	20	
D03	D02	C	0.0001	0.0001	20	
D01	D02	C	0.001	0.001	20	
G01	A03	C	0.001	0.001	20	
G02	A08	C	0.001	0.001	20	

Table A-2 Load data in MW and MVAr

Busbar	Real Power (MW)	Reactive Power (MVAr)
A01	0.284	0.137
A02	0.36	0.174
A05	0.809	0.392
A06	0.809	0.392
A09	0.405	0.196
A13	0.518	0.251
B01	0.305	0.148
B03	0.155	0.075
B04	0.258	0.125
B05	0.293	0.142
B08	0.675	0.327
B07	0.314	0.152
B07	0.596	0.288
C02	0.09	0.044
C05	0.675	0.327
C07	0.675	0.327
C01	0.207	0.1
C12	0.202	0.098

C15	0.293	0.142
C16	0.173	0.084
C17	0.241	0.117
C18	0.067	0.033
C19	0.158	0.076

Table A-3 Transformer data

From Busbar	To Busbar	Minimum Tap (%)	Tap Step (%)	Maximum Tap (%)	Relay Bandwidth (%)
S01	D01	-10	0.5	10	1.5
S01	D02	-10	0.5	10	1.5

A.2 Load Profile Data

Table A-4 Normalised winter weekday loading profile in MW

Time	profile1	profile2	profile3	profile4	profile5	profile6	profile7	profile8	average
00:00	0.445652	0.305221	0.19797	0.417279	0.156743	0.230541	0.377157	0.67051	0.418864
00:15	0.402174	0.369478	0.187817	0.480699	0.162215	0.231201	0.365079	0.648847	0.425808
00:30	0.358696	0.433735	0.177665	0.544118	0.167688	0.23186	0.353002	0.627184	0.432752
00:45	0.331522	0.64257	0.186548	0.631434	0.175788	0.230871	0.347136	0.617575	0.473052
01:00	0.304348	0.851406	0.195431	0.71875	0.183888	0.229881	0.34127	0.607966	0.513351
01:15	0.288043	0.919679	0.196701	0.78125	0.201182	0.226913	0.33989	0.603948	0.531993
01:30	0.271739	0.987952	0.19797	0.84375	0.218476	0.223945	0.338509	0.59993	0.550635
01:45	0.26087	0.993976	0.195431	0.845588	0.222417	0.220976	0.336784	0.596785	0.549223
02:00	0.25	1	0.192893	0.847426	0.226357	0.218008	0.335059	0.593641	0.547811
02:15	0.244565	0.985944	0.192893	0.847426	0.220884	0.216524	0.333333	0.589623	0.542997
02:30	0.23913	0.971888	0.192893	0.847426	0.215412	0.21504	0.331608	0.585604	0.538183
02:45	0.233696	0.955823	0.191624	0.840993	0.210158	0.215534	0.330055	0.583159	0.532507
03:00	0.228261	0.939759	0.190355	0.834559	0.204904	0.216029	0.328502	0.580713	0.526831
03:15	0.228261	0.903614	0.190355	0.823529	0.201182	0.21504	0.327467	0.580887	0.518943
03:30	0.228261	0.86747	0.190355	0.8125	0.197461	0.21405	0.326432	0.581062	0.511056
03:45	0.222826	0.819277	0.190355	0.79136	0.193301	0.212731	0.324362	0.580713	0.498694
04:00	0.217391	0.771084	0.190355	0.770221	0.189142	0.211412	0.322291	0.580363	0.486333
04:15	0.217391	0.740964	0.192893	0.755515	0.192644	0.210752	0.321084	0.580713	0.480306
04:30	0.217391	0.710843	0.195431	0.740809	0.196147	0.210092	0.319876	0.581062	0.474279
04:45	0.222826	0.688755	0.19797	0.729779	0.198336	0.209598	0.321774	0.581412	0.471108
05:00	0.228261	0.666667	0.200508	0.71875	0.200525	0.209103	0.323671	0.581761	0.467938
05:15	0.233696	0.64257	0.201777	0.705882	0.198555	0.216194	0.327295	0.586827	0.465478
05:30	0.23913	0.618474	0.203046	0.693015	0.196585	0.223285	0.330918	0.591894	0.463018
05:45	0.25	0.604418	0.211929	0.685662	0.195053	0.236148	0.339199	0.59993	0.466905

06:00	0.26087	0.590361	0.220812	0.678309	0.19352	0.249011	0.347481	0.607966	0.470791
06:15	0.298913	0.590361	0.233503	0.686581	0.206217	0.267315	0.372671	0.622117	0.490134
06:30	0.336957	0.590361	0.246193	0.694853	0.218914	0.28562	0.397861	0.636268	0.509476
06:45	0.380435	0.584337	0.271574	0.689338	0.241025	0.307718	0.428054	0.652516	0.531603
07:00	0.423913	0.578313	0.296954	0.683824	0.263135	0.329815	0.458247	0.668763	0.55373
07:15	0.494565	0.560241	0.32868	0.682904	0.310201	0.374505	0.494997	0.697764	0.589752
07:30	0.565217	0.542169	0.360406	0.681985	0.357268	0.419195	0.531746	0.726765	0.625775
07:45	0.625	0.467871	0.40736	0.67739	0.426664	0.476748	0.570738	0.757338	0.659324
08:00	0.684783	0.393574	0.454315	0.672794	0.49606	0.534301	0.609731	0.787911	0.692874
08:15	0.679348	0.34739	0.521574	0.702206	0.608363	0.625165	0.662353	0.823899	0.743243
08:30	0.673913	0.301205	0.588832	0.731618	0.720665	0.716029	0.714976	0.859888	0.793611
08:45	0.646739	0.273092	0.659898	0.784926	0.796848	0.797823	0.76225	0.882774	0.838057
09:00	0.619565	0.24498	0.730964	0.838235	0.87303	0.879617	0.809524	0.90566	0.882503
09:15	0.592391	0.232932	0.812183	0.879596	0.910902	0.922658	0.84334	0.922781	0.914685
09:30	0.565217	0.220884	0.893401	0.920956	0.948774	0.965699	0.877157	0.939902	0.946866
09:45	0.554348	0.212851	0.927665	0.936581	0.959063	0.975923	0.89648	0.952481	0.959338
10:00	0.543478	0.204819	0.961929	0.952206	0.969352	0.986148	0.915804	0.965059	0.97181
10:15	0.538043	0.198795	0.970812	0.969669	0.967163	0.989281	0.941339	0.96768	0.978387
10:30	0.532609	0.192771	0.979695	0.987132	0.964974	0.992414	0.966874	0.9703	0.984965
10:45	0.527174	0.190763	0.984772	0.993566	0.97373	0.994063	0.974638	0.974319	0.988891
11:00	0.521739	0.188755	0.989848	1	0.982487	0.995712	0.982402	0.978337	0.992817
11:15	0.516304	0.186747	0.992386	0.996324	0.989711	0.997856	0.986715	0.984801	0.994546
11:30	0.51087	0.184739	0.994924	0.992647	0.996935	1	0.991028	0.991265	0.996276
11:45	0.51087	0.188755	0.997462	0.98989	0.998468	1	0.994134	0.995283	0.998138
12:00	0.51087	0.192771	1	0.987132	1	1	0.997239	0.999301	1
12:15	0.521739	0.198795	0.993655	0.97886	0.985333	0.996042	0.99862	0.998602	0.997657
12:30	0.532609	0.204819	0.98731	0.970588	0.970665	0.992084	1	0.997904	0.995314
12:45	0.532609	0.202811	0.969543	0.960478	0.948555	0.982685	0.996204	0.998952	0.985723
13:00	0.532609	0.200803	0.951777	0.950368	0.926445	0.973285	0.992409	1	0.976131
13:15	0.521739	0.196787	0.928934	0.941176	0.921848	0.968338	0.98913	0.997379	0.966806
13:30	0.51087	0.192771	0.906091	0.931985	0.91725	0.963391	0.985852	0.994759	0.95748
13:45	0.5	0.188755	0.902284	0.920956	0.908713	0.96438	0.981884	0.990391	0.95066
14:00	0.48913	0.184739	0.898477	0.909926	0.900175	0.965369	0.977916	0.986024	0.94384
14:15	0.483696	0.184739	0.898477	0.902574	0.89711	0.962566	0.971532	0.978512	0.938973
14:30	0.478261	0.184739	0.898477	0.895221	0.894046	0.959763	0.965148	0.970999	0.934105
14:45	0.48913	0.188755	0.895939	0.888787	0.883975	0.955145	0.95842	0.966108	0.931055
15:00	0.5	0.192771	0.893401	0.882353	0.873905	0.950528	0.951691	0.961216	0.928006
15:15	0.505435	0.196787	0.885787	0.878676	0.851357	0.94591	0.946687	0.9558	0.92211
15:30	0.51087	0.200803	0.878173	0.875	0.828809	0.941293	0.941684	0.950384	0.916215
15:45	0.543478	0.210843	0.86802	0.86489	0.820271	0.931069	0.937888	0.95021	0.916163
16:00	0.576087	0.220884	0.857868	0.854779	0.811734	0.920844	0.934092	0.950035	0.916111
16:15	0.63587	0.242972	0.845178	0.840993	0.785902	0.905178	0.930987	0.95318	0.918195
16:30	0.695652	0.26506	0.832487	0.827206	0.76007	0.889512	0.927881	0.956324	0.920279
16:45	0.771739	0.297189	0.810914	0.803309	0.70359	0.859334	0.9196	0.959119	0.915883

17:00	0.847826	0.329317	0.78934	0.779412	0.64711	0.829156	0.911318	0.961915	0.911486
17:15	0.907609	0.353414	0.73731	0.733456	0.584063	0.779848	0.891822	0.960517	0.889451
17:30	0.967391	0.37751	0.685279	0.6875	0.521016	0.730541	0.872326	0.959119	0.867416
17:45	0.983696	0.389558	0.607868	0.625919	0.452933	0.657487	0.856798	0.955451	0.826896
18:00	1	0.401606	0.530457	0.564338	0.384851	0.584433	0.84127	0.951782	0.786375
18:15	1	0.407631	0.474619	0.527574	0.348511	0.514677	0.80383	0.946366	0.751155
18:30	1	0.413655	0.418782	0.490809	0.312172	0.444921	0.766391	0.94095	0.715935
18:45	0.994565	0.411647	0.397208	0.46875	0.294002	0.404189	0.723257	0.937456	0.692516
19:00	0.98913	0.409639	0.375635	0.446691	0.275832	0.363456	0.680124	0.933962	0.669098
19:15	0.972826	0.399598	0.365482	0.436581	0.264667	0.337071	0.664251	0.930643	0.653644
19:30	0.956522	0.389558	0.35533	0.426471	0.253503	0.310686	0.648378	0.927324	0.638189
19:45	0.934783	0.379518	0.343909	0.417279	0.238179	0.291722	0.633368	0.918414	0.62165
20:00	0.913043	0.369478	0.332487	0.408088	0.222855	0.272757	0.618357	0.909504	0.605111
20:15	0.891304	0.365462	0.323604	0.398897	0.210595	0.267315	0.590407	0.892907	0.589249
20:30	0.869565	0.361446	0.314721	0.389706	0.198336	0.261873	0.562457	0.87631	0.573386
20:45	0.858696	0.355422	0.303299	0.380515	0.196804	0.259894	0.535714	0.86443	0.561477
21:00	0.847826	0.349398	0.291878	0.371324	0.195271	0.257916	0.508972	0.852551	0.549568
21:15	0.842391	0.34739	0.280457	0.362132	0.187391	0.252474	0.496204	0.84137	0.539799
21:30	0.836957	0.345382	0.269036	0.352941	0.17951	0.247032	0.483437	0.830189	0.530031
21:45	0.809783	0.337349	0.258883	0.350184	0.175788	0.244888	0.47205	0.816212	0.518166
22:00	0.782609	0.329317	0.248731	0.347426	0.172067	0.242744	0.460663	0.802236	0.506301
22:15	0.755435	0.323293	0.239848	0.344669	0.170753	0.241095	0.446687	0.782145	0.494059
22:30	0.728261	0.317269	0.230964	0.341912	0.16944	0.239446	0.432712	0.762055	0.481817
22:45	0.684783	0.307229	0.227157	0.338235	0.165718	0.236478	0.425121	0.747729	0.468417
23:00	0.641304	0.297189	0.22335	0.334559	0.161996	0.233509	0.417529	0.733403	0.455017
23:15	0.586957	0.281124	0.217005	0.334559	0.155648	0.232685	0.411318	0.718728	0.439343
23:30	0.532609	0.26506	0.21066	0.334559	0.149299	0.23186	0.405107	0.704053	0.423669
23:45	0.48913	0.285141	0.204315	0.375919	0.153021	0.231201	0.391132	0.687282	0.421266
00:00	0.48913	0.285141	0.204315	0.375919	0.153021	0.231201	0.391132	0.687282	0.421266
00:15	0.48913	0.285141	0.204315	0.375919	0.153021	0.231201	0.391132	0.687282	0.421266
00:30	0.48913	0.285141	0.204315	0.375919	0.153021	0.231201	0.391132	0.687282	0.421266

A.3 DG Profile Data

Table A-5 Normalised DG daily generation output in MW

Time	WIND	PV	CHP
00:00	0.2239	0	0.551724
00:15	0.3544	0	0.551724
00:30	0.4444	0	0.551724
00:45	0.3232	0	0.551724
01:00	0.4141	0	0.551724

01:15	0.3889	0	0.551724
01:30	0.1944	0	0.551724
01:45	0.2433	0	0.551724
02:00	0.3325	0	0.551724
02:15	0.2719	0	0.551724
02:30	0.2753	0	0.551724
02:45	0.3056	0	0.551724
03:00	0.3241	0	0.551724
03:15	0.2727	0	0.551724
03:30	0.4015	0	0.551724
03:45	0.4857	0	0.551724
04:00	0.3796	0	0.551724
04:15	0.4689	0	0.558621
04:30	0.4327	0	0.565517
04:45	0.5269	0	0.575862
05:00	0.4108	0	0.586207
05:15	0.3754	0	0.603448
05:30	0.6768	0	0.62069
05:45	0.6987	0	0.655172
06:00	0.7466	0	0.689655
06:15	0.5934	0.033333	0.724138
06:30	0.7306	0.066667	0.758621
06:45	0.5758	0.083333	0.827586
07:00	0.9444	0.1	0.896552
07:15	0.9276	0.116667	0.931034
07:30	0.9697	0.133333	0.965517
07:45	0.8535	0.15	0.97931
08:00	0.6675	0.166667	0.993103
08:15	0.6919	0.183333	0.996552
08:30	0.7618	0.2	1
08:45	0.8746	0.233333	0.996552
09:00	0.7626	0.266667	0.993103
09:15	0.5303	0.3	0.986207
09:30	0.447	0.333333	0.97931
09:45	0.3611	0.366667	0.972414
10:00	0.3274	0.4	0.965517
10:15	0.2854	0.483333	0.965517
10:30	0.4015	0.566667	0.965517
10:45	0.4554	0.6	0.965517
11:00	0.6237	0.633333	0.965517
11:15	0.2879	0.683333	0.965517
11:30	0.3476	0.733333	0.965517
11:45	0.3384	0.833333	0.965517
12:00	0.6625	0.933333	0.965517

12:15	0.75	0.966667	0.965517
12:30	0.734	1	0.965517
12:45	0.8173	1	0.965517
13:00	0.8182	1	0.965517
13:15	0.6414	0.883333	0.965517
13:30	0.4899	0.766667	0.965517
13:45	0.3476	0.75	0.965517
14:00	0.3114	0.733333	0.965517
14:15	0.5253	0.716667	0.965517
14:30	0.5783	0.7	0.965517
14:45	0.6734	0.666667	0.965517
15:00	0.5833	0.633333	0.965517
15:15	0.5556	0.583333	0.965517
15:30	0.5631	0.533333	0.965517
15:45	0.5379	0.5	0.965517
16:00	0.314	0.466667	0.965517
16:15	0.33	0.433333	0.965517
16:30	0.303	0.4	0.965517
16:45	0.3923	0.416667	0.965517
17:00	0.4091	0.433333	0.965517
17:15	0.2837	0.4	0.965517
17:30	0.3822	0.366667	0.965517
17:45	0.4217	0.316667	0.958621
18:00	0.2837	0.266667	0.951724
18:15	0.4167	0.2	0.941379
18:30	0.5791	0.133333	0.931034
18:45	0.447	0.1	0.913793
19:00	0.6338	0.066667	0.896552
19:15	0.521	0.033333	0.87931
19:30	0.447	0	0.862069
19:45	0.4184	0	0.844828
20:00	0.3611	0	0.827586
20:15	0.3056	0	0.810345
20:30	0.3864	0	0.793103
20:45	0.4832	0	0.775862
21:00	0.4891	0	0.758621
21:15	0.5606	0	0.741379
21:30	0.5892	0	0.724138
21:45	0.7685	0	0.706897
22:00	0.7155	0	0.689655
22:15	0.521	0	0.672414
22:30	0.4882	0	0.655172
22:45	0.5539	0	0.637931
23:00	0.5732	0	0.62069

23:15	0.4739	0	0.593103
23:30	0.4436	0	0.565517
23:45	0.5463	0	0.565517
00:00	0.3476	0	0.565517
00:15	0.2668	0	0.558621
00:30	0.2247	0	0.558621