DEPARTMENT OF ELECTRONIC & ELECTRICAL ENGINEERING

University of Strathclyde Engineering

Maximising Wind Farm Connections: An Investigation of Novel Voltage Management and Principles of Access Techniques in Active Distribution Networks

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

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Abstract

Power production from stochastic wind generators connected at the lower voltage levels on the distribution network where weak strength of the network prevails, can make voltage management particularly challenging for network operators. Distribution network operators (DNO's) tend to manage their networks conservatively by imposing stricter operational limits when deciding whether to allow generators to connect or not. Voltage rise limitation is a major barrier and impacts significantly on the capacities of generators that can be connected at lower voltage and weak distribution networks.

This thesis develops and presents novel voltage control techniques which involves a coordination of active network management (ANM) technological solutions and principles of access (PoA) arrangements specific for wind farm connections managed under voltage constraint conditions. The proposed coordinated voltage control and PoA techniques effectively mitigate the voltage rise limitation and enhance the capacity of the network to connect more wind generation. The research presented assesses the performance of the strategy and it quantifies the benefit to the wind generators by using time-series optimal power flow methods on a realistic UK 11 kV distribution network.

The proposed ANM solution provides DNO's alternative control options to address the voltage rise problem to facilitate cheaper and faster DG connections, deferring the need for costly and time-consuming reinforcement. It offers wind farm owners, flexible options to minimise excessive curtailment by controlling their voltage at the point of connection. It provides a guide for suitable locations for future wind farm investment. It quantifies the risks and uncertainties associated with the different commercial arrangements and proposes alternative PoA suitable for voltage constrained networks.

Declaration

Good, better, best

May I never rest

Until my good is better, and my better is best

(my favourite nursery rhyme)

Acknowledgements

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I would like to thank my wife Marian, who has been a backbone and a solid rock, my two daughters, Lexin and Zanelle for bringing me the greatest happiness and the reason for my hard work.

My thanks also go to my parents Harry and Agatha Danzerl and siblings for their love, care and support. I would also like to thank my parents-in-law Anthony and Evelyn Quartey-Papafio for their words of encouragement.

I dedicate this thesis to my wife and children and to you the reader for your time.

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List of Abbreviations

AC	Alternating Current
AVC	Automatic Voltage Control
AVR	Automatic Voltage Regulation
ANM	Active Network Management
BaU	Business as Usual
CC	Connection Condition
CF	Capacity Factor
CHP	Combined Heat and Power
CNLP	Constrained Non-Linear Programming
CPF	Constant Power Factor
CVC	Coordinated Voltage Control
DB	Deadband
DFIG	Doubly Fed Induction Generator
DG	Distributed Generators
DGO	Distributed Generation Operators
DLR	Dynamic Line Rating
DMS	Distribution Management System
DNO	Distributed Network Operators

DPC	Distribution Planning Code
DWG	Distributed Wind Generators
EG	Embedded Generation
EHV	Extra High Voltage
ESQC	Electricity Safety Quality and Continuity
ETB	Enhanced Technical Best
EU	European Union
FRC	Fully Rated Converter
GA	Genetic Algorithm
GB	Great Britain
GSP	Grid Supply Point
HV	High Voltage
PoA	Principles of Access
PCC	Point of Common Coupling
POC	Point of Connection
PWM	Pulse Width Modulation
IGBT	Insulated-Gate Bipolar Transistor
IP	Interior Point
LCNF	Low Carbon Network Fund
LDC	Line Drop Compensator
LIFO	Last-in-First Out
NFG	Non Firm Generation
NGET	National Grid Electricity Transmission

NNFG	New Non Firm Generation
LV	Low Voltage
NLP	Non Linear Programming
MC	Most Convenient
MIP	Mixed Interior Programming
MV	Medium Voltage
OFGEM	Office of Gas and Electricity Market
OLTC	On-Load Tap Changer
OPF	Optimal Power Flow
PFC	Power Factor Control
RPD	Reactive Power Dispatch
RPZ	Registered Power Zone
SCADA	Supervisory Control and Data Acquisition
SVC	Static VAr Compensator
SVR	Step Voltage Regulator
TCR	Thyristor Controlled Reactor
TSC	Thyristor Switched Capacitor
X/R	Reactance to Resistance ratio
UK	United Kingdom
UKGDS	United Kingdom Generic Distribution System
VC	Voltage Control
VPF	Variable Power Factor

Chapter 1

INTRODUCTION

1.1 Wind energy integration in the UK

Rising environmental pollution and greenhouse gases resulting from electricity generation process places huge responsibilities on energy producers to significantly reduce CO_2 emissions that contribute to climate change. Global climate change has been identified as one of the greatest threats to growth, security and prosperity in society [1]. The generation of electricity from renewable energy resources offers an immediate and alternative solution which can reduce the harmful emissions from conventional power generation processes [2]. The 2007 EU requirement to provide 20% of all energy used in Europe from renewable resources by 2020 [3], provides a roadmap for the UK's renewable energy policy initiatives. The EU's renewable energy target for the UK is currently set at 15% of all energy to be sourced from renewables by 2020. This translates into 35% of electrical energy [4].

Over the past decade, the role of wind energy generation in the UK has been under the spot light. Within this period, the growth of wind energy contributions to the UK's electricity demand has increased from less than 1% to 10%, making wind energy the UK's single biggest source of renewable power [5]. Wind energy alone provides more renewable electricity (nearly 50% of the total) than all other resources combined. By 2015, a total capacity of $13,313$ MW had been installed, comprising 648 MW built onshore wind and $1,394$ MW offshore wind.

Figure 1.1 illustrates a trend in recent growth of UK's wind energy production.

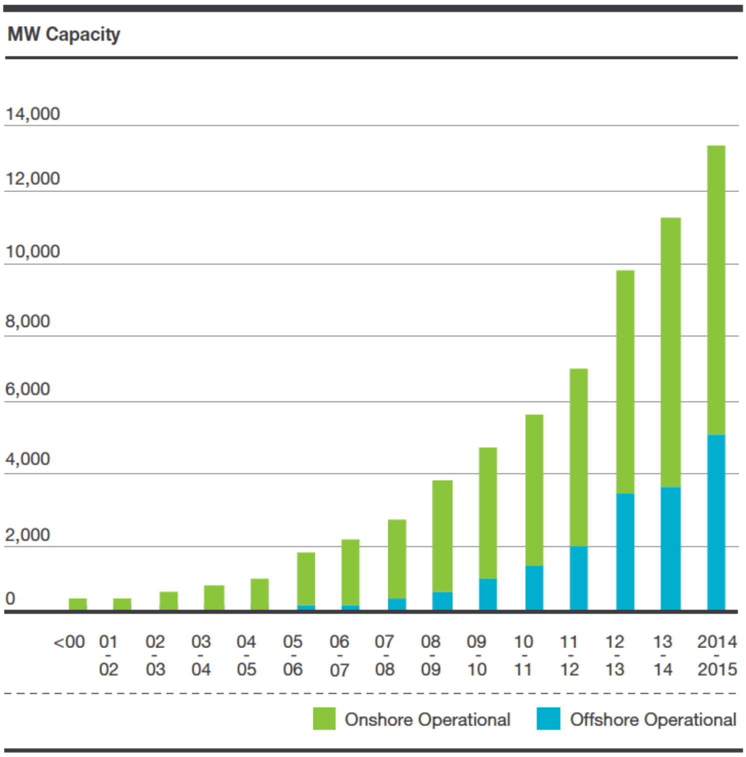


Figure 1.1: The growth of wind generation in the UK [5]

The growth of onshore wind has been significantly rapid throughout this period. In 2016, there was a major switch from traditional electricity generation from coal. Electricity generation from coal fell by 60%, because of plant closures and transition to source electricity production from alternative and other sustainable resources. Renewables share of the generation mix remained stable at 25% between 2015 and 2016 [6]. The map presented in Figure 1.2 shows the various locations of wind farm operations in the UK by the end of 2016, along with an indication of installed capacities. The total number of operational wind farms by the end of December 2016 was recorded at 14, 565. This figure includes 13, 100 onshore wind farms and 1, 465 offshore wind farms.

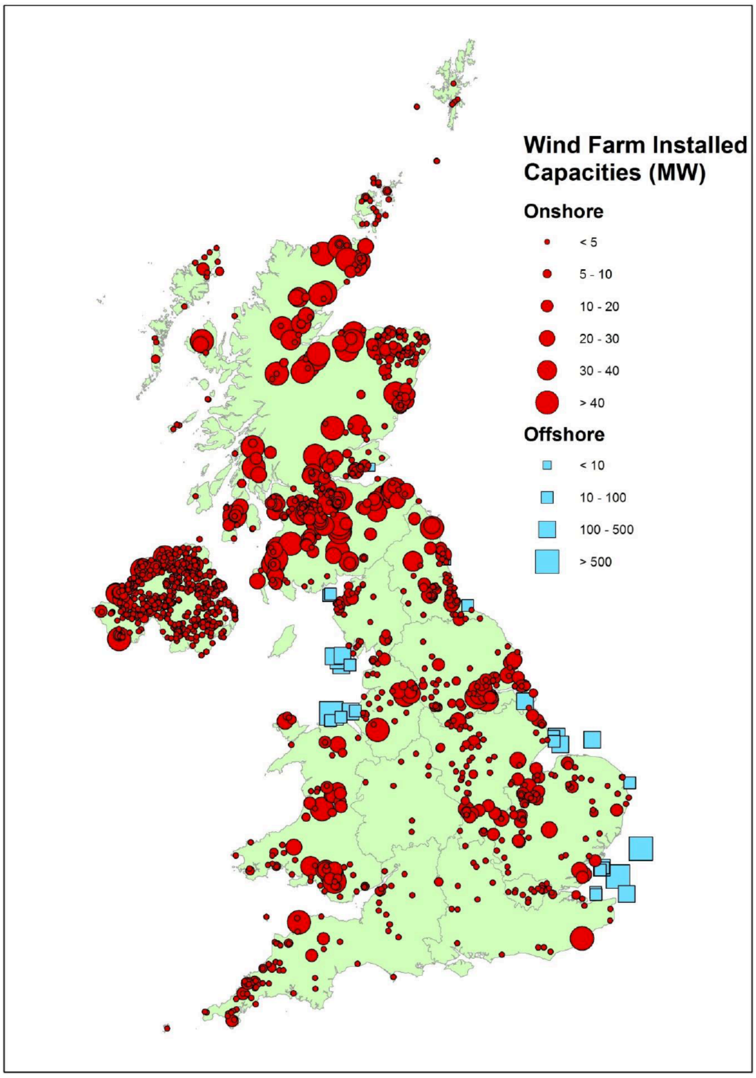


Figure 1.2: Location of wind farms in the UK at the end of 2016 [6]

The GB network is currently no longer dominated by large centralised generators, but rather made up of an increased number of renewables mixed with conventional generators. The distribution network has become an active and integrated system with power flows and voltages determined by the generators and loads. With most of the UKs renewable energy resources (wind, wave, tidal) dispersed in rural and less densely populated areas, the closest and most economic point of connection (POC) for distributed generators (DG's) is sometimes at the electrically weak, remote and low voltage levels. Connection of wind generation at lower distribution voltages allows for cheaper connection charges, reduced capital cost and in many areas offers the only connection option within a feasible distance of the development [7].

The new changes to the distribution network and energy mix have been innovative and a step in the right direction [8]. However, it has been associated with significant technical and commercial challenges to current distribution network planning and operations [9–11]. The network has been subjected to power quality issues, increased losses, protection issues, congestion and bidirectional power flows causing an increase in voltage magnitudes and interference to voltage control devices. In a bid to preserve and maintain the power system security, distribution network operators (DNOs) tend to set their own stringent connection agreement that must be adhered to, or the DGs are penalised by disconnection from the network [12]. These strict connection agreements are usually established based on worst-case scenario (maximum generation minimum loads) conditions of passively managing the network which results in underutilised network capacities and reduced economic viability for the DGs [13].

1.2 Voltage rise issues at weak distribution networks

Deployment of DGs on the electricity grid can have positive impacts and some negative impacts if integration is not managed properly. This is true for the stochastic nature of some DGs like wind and solar which have fluctuating power outputs [14]. The technologies themselves vary significantly in their operation and impact. Distributed generators like small combined heat and power (CHPs) plants, micro-hydro plants and bioenergy generally have limited dependencies on weather hence offer relatively constant and predictable power output when compared with weather dependent renewables like wind and solar. Figure 1.3 represents the overall impact of DGs on the grid in two-dimensional space where time scale and impact area are the coordinates. At the distribution network level, DGs have local impact on power quality, congestion issues, distribution efficiencies and voltage management issues and the time scales for relevant impact studies occurring within a short time interval. Voltage management issues at the distribution level is the major focus of this thesis.

At certain extreme circumstances, the amount of DG connections at the distribution network level may significantly impact the grid. The implications of such impacts could be both regional (grid stability, transmission efficiency, congestion management and adequacy of grid) and system wide (reserves, hydro/thermal efficiency, emissions and adequacy of energy/power). Similar scenarios has already occurred in countries such as Germany, Denmark, Spain, Italy, Portugal and Ireland where there are significant penetration of wind, solar and combined heat and power units [15] embedded in the grid.

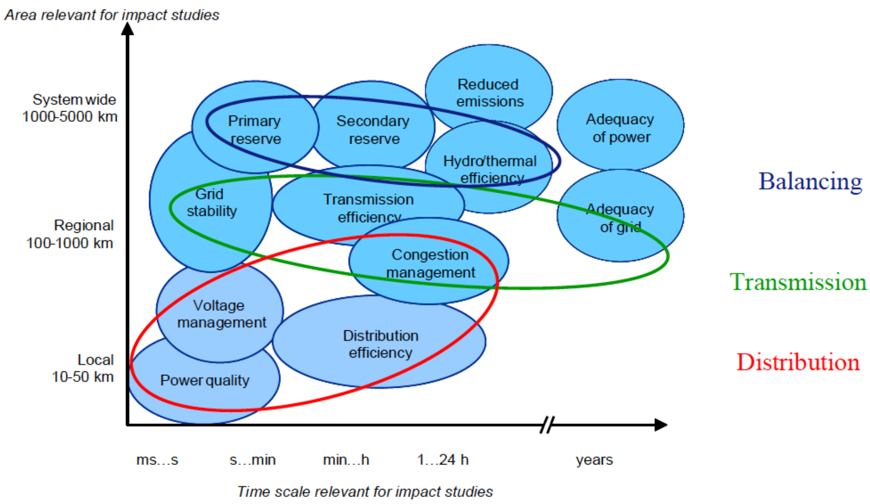


Figure 1.3: Impact of distributed generation on electricity system [15]

Distribution network overhead lines and underground cables are characterised by their high resistance and such conditions can lead to large voltage drops when the lines are loaded. Therefore, significant loading of the network whether through injection by DGs or high demand condition will result in voltage variations on the distribution network [16]. Increasing the capacity of DG connections on the distribution network makes voltage management particularly challenging. Over-voltage condition occur when DGs operate at maximum power output during periods of low demand, causing power to flow back up the network. This condition is termed as reverse power flow. Here, the voltage at the end of the distribution feeder becomes greater than the voltage at the primary substation and such condition is known as *voltage rise* effect [17].

Connections of distributed generation (DG) at weak and lower voltage distribution networks are highly susceptible to voltage rise issues and is a major factor which limits greater penetration of DGs at rural networks [17] [18]. To minimise the impact of DGs, network operators usually prefer to connect the generators at higher voltage levels where their impact on voltage rise issues are minimal. However, the commercial viability of connecting DGs at higher voltage penetration levels is sensitive to cost of connection. Generally, the higher the voltage or sparser the network, the higher the cost of connection [13]. Consequently, voltage control requirements associated with DG integration issues have been a major priority for DNOs in terms of their statutory obligation to maintain the network voltages within pre-set limits. The electricity supply regulations in the UK (1988) stipulate that, the statutory steady-state voltage of the network should be maintained within $\pm 6\%$ of the nominal voltage [19]. The task of voltage control is to ensure that the node voltages are kept within the required limits.

However, the DNOs tend to manage their network according to a set of predefined operational limits (usually $\pm 3\%$ for 11kV networks) which are stricter than the statutory limits [17]. This is to ensure safe, reliable and secured operations of their network assets and also to demonstrate strict compliance with regulations to avoid incurring heavy penalty charges by the regulator (Office of gas and electricity markets) if the limits are breached. DG connection capacities are passively established based on worst-case scenario conditions of the network. The passive approach to network management leads to underutilised network assets and capacities of economically viable generators. The voltage constraint problem has raised major concerns and has led to the regulator, network operators, DG owners, investors and other stakeholders into finding viable technical and economical solutions that are able to address the problem.

1.3 Towards active distribution networks

The move towards an active operation of the distribution network has been adopted in the UK over the past decade through active network management (ANM). This new technology allows an increased capacity of distributed generators to connect under the condition that their power output are curtailed when required to maintain network constraint limits (mainly thermal and voltage limits). Curtailment schemes through non-firm contracts has enabled cheaper and faster connections of large number of intermittent generators on the distribution network across the UK. The introduction of non-firm wind generation increases the capacity of renewable generation on the distribution network.

However, each unit of non-firm capacity provides less benefit due to potential power output being curtailed. Gaining the greatest benefit from the non-firm wind farm generators will involve minimising significant amount and frequency of curtailment [20]. Two methods for achieving this are outlined and forms the basis of this research:

1. Investigating corrective measures that mitigate the voltage rise limitation without reinforcing the network.

2. Identifying alternative and suitable commercial arrangements that maximises the benefit of the wind farms when managed under voltage constraint conditions.

1.4 Focus of thesis

Voltage, thermal and fault level constraint issues has become major barriers to greater DG connections on the distribution network. The interaction and correlation between the constraints have significant bearings on the capacities of wind farm that can connect to the distribution network. This thesis has been motivated by the desire to contribute to the technical and economic viability of wind farm connections on the distribution network. Although all the network constraints are equally important and worth discussing, the research presented in this thesis however addresses the voltage rise constraint issues associated with wind farm connections at weak distribution networks. It investigates the planning and operation arrangement to distribution network management with particular attention on voltage constraint issues.

The research methodology models current ANM technological solutions involving a coordination of DG active power curtailment, on-load tap changing transformer (OLTC) operations and reactive power dispatch from the wind turbine generators.

The proposed voltage control approach attempts to maximise DG connection capacities at a minimum cost and provides alternative control options that defers or avoids capital intensive network upgrades.

The thesis analyses principles of access (PoA) arrangement specific for wind farm connections managed under network voltage constraint conditions. It evaluates and challenges the current DNO practice and commercial arrangement for connecting non-firm wind farms managed under thermal constraint conditions and assesses it's effectiveness when applied under voltage constraint conditions. It proposes alternative PoA solutions that aim to maximise wind farm connections when managed under voltage constraint conditions. The proposed PoA strategy optimises and effectively utilises the existing headroom capacity, enabling greater network access for remotely connected generators. This study undertakes quantitative assessments of subsequent energy yields, economic benefit and curtailment levels of multiple wind farm connections using a case-study network. The case-study network is based on a representative UK generic distribution system (UKGDS) with analysis focusing on the interactions of voltage rise constraint and non-firm wind generation.

1.5 Objectives of thesis

The key question which this thesis attempts to answer is:

- **How can we overcome the voltage rise limitation for DG connections at weak distribution networks? Are there suitable control actions and alternative principle of access techniques that can be coordinated effectively to maximise the benefit of wind generation connections in ANM schemes?**

This thesis aim to maximise the integration of distributed wind generators in the most cost-effective way. To achieve this, active voltage control methods and distribution network planning procedures are developed. The main objectives of this thesis can be summarised as follows:

- To assess the impact of voltage rise limitations on wind farms connected at lower voltage and weak distribution networks.
- To develop active voltage control techniques that mitigate the voltage rise limitation and implement flexible alternative solutions that releases additional network capacity.
- To investigate alternative principles of access (PoA) arrangement that favours greater wind farm connections at network conditions where voltage constraint is binding.
- To develop a coordinated ANM technological solutions that maximises wind farm connections in active distribution networks.
- To demonstrate the operation of the developed voltage control strategy and principles of access (PoA) on a realistic UK distribution network to assess the performance and benefit to the wind farms.

To fully address the key research questions and objectives, there are requirements to develop essential tools that models the voltage rise problem at weak distribution networks. The methodology formulates the research question as a multi-objective optimisation problem with constraints and applies non-linear programming (NLP) techniques to addresses the issue. Power system optimisation methods such as optimal power flow (OPF) analysis tools are adopted and implemented on a representative UK generic distribution network assumed to operate an ANM scheme to quantify the benefit to the wind generators.

1.6 Methodology

The thesis uses the following research methods to address the key questions and objectives:

- Undertakes an extensive review of existing literature on voltage management methods at passive distribution networks, including lessons learnt for future network applications.

- Review existing literature on voltage management techniques of current active distribution networks with high penetration of distributed generation connections.
- Review existing principle of access (PoA) philosophy for non-firm DG connections at thermally constraint distribution networks, identifying suitable possible alternatives that could be applied for voltage constraint networks.
- Review optimisation methods currently applied for constraint management in ANM operations, particularly those based on optimal power flow (OPF) techniques. The optimisation tools developed will be applied to the operation of the non-firm DGs in active distribution networks and quantify the benefit to the wind farms.
- Model distribution voltage control through curtailment and the application of existing principles of access (PoA) techniques in ANM operations. Identify a suitable list of assessment criteria against which the PoA can be benchmarked.
- Investigate distribution voltage control through optimised operation of on-load tap changing transformers (OLTC) operations with aim to improve network hosting capacity to accommodate high wind penetration levels.
- Model distribution voltage control methods that utilises the reactive power capabilities of the wind turbine generators in ANM schemes.
- Develop a coordinated voltage control (CVC) strategy and alternative principle of access (PoA) techniques that maximises the economic viability of the wind farms.
- Evaluate the economic benefit, risks and uncertainties that may be faced by the wind farm developers when the proposed voltage control strategy and principles of access are implemented.
- Demonstrate the benefit of the proposed strategy using a generic UK distribution case-study network, quantifying the impact on viable generation capacities and curtailment that may be experienced by the wind farm generators.

- Investigate the potential to reduce further wind farm curtailment using possible alternative and cost effective solutions including; changes in network operational limits potentially deferring the need for time consuming and costly network upgrades.

1.7 Contributions to knowledge

This thesis delivers a number of important contributions to power system studies and engineering in terms of both knowledge and novel techniques. The novelty and contributions of this work particularly lies in the field of distribution network management, renewable integration and smart grid research.

1. **An approach for assessing PoA of multiple wind farm connections**

   It is the first study to assess quantitatively, the performance of non-firm DGs when the current PoA rules are applied under network voltage constraint conditions. A qualitative assessment criteria is developed to compare the different PoA rules highlighting their major benefits, drawbacks and network applications. The studies undertaken here opens up discussions and provides a foundation for investigating and developing alternative PoA methods suitable for voltage constraint networks. (Chapter 3).

2. **Optimisation of ANM technological solutions for voltage rise mitigation**

   It provides the first study to address the voltage rise problem through the application of optimised set-point voltage technique of distribution on-load tap changing transformers. The approach aim to improve network hosting capacity using OPF analysis methods. The optimisation technique enhances DG voltage margins and minimises the impact of active generation on voltage profiles. (Chapter 4).

   A decentralised approach to distribution voltage control that fully utilises the reactive power capabilities of distributed wind generators (DWG) is an emerging technology and one that has not yet been investigated extensively. This thesis models the problem and provides the first study to an example of a second-generation ANM technological solution that employs greater participation from the wind turbines to resolve the voltage constraint problem. (Chapter 5).

3. **Develops a coordinated voltage control strategy that combines ANM technological solutions and PoA for distributed wind generation connections**

   The framework presented in the earlier chapters extends and combines the formulation of the ANM control actions with principles of access (PoA) for wind farms connections at voltage constraint distribution networks. It develops a novel voltage control strategy and adopts a hierarchical and systematic approach to implementing the control actions with aim to maximise wind energy output. The development of an extensive multi-period OPF technique is used to assess the performance of the proposed technique when applied to a representative UK generic distribution case-study network. The case study provides an example of how the proposed methodology can be applied to a realistic network. The outcome of the study is presented in Chapter 6 and it shows that, significant growth in wind energy levels can be realised as we implement and move up the proposed voltage control hierarchy. It demonstrates the benefit to the wind generators when the ANM solutions and PoA are effectively coordinated.

   It defines and proposes new principles of access framework for multiple DWG connections when managed under voltage constraint conditions. The newly proposed PoA regime is assessed under likely changes in future network operation conditions and scenarios (Chapter 7). These includes a quantitative assessment on generation levels and performance of the wind farms when the conditions are applied and it includes; re-powering opportunities for remotely connected DWGs, addition of further wind farm development and connections at random and strong bus location with existing wind farms.

The demonstration of the proposed strategy under the likely changes in the network's future operations provides a criterion to validate and test the robustness of the newly defined PoA when benchmarked with current DNO practice. It presents and models the opportunity to maximise DG connection capacities through changes to current DNO management and operation practise. It explores the potentials to reduce further DG curtailment by relaxing of voltage constraint limits and adopting a flexible power factor control regime.

1.8 List of Publications

Through the development of this thesis, the author has published the following works as the main contributing author.

1.8.1 Journal Publications

- **D. Danzerl**, S. Gill, and O. Anaya-Lara, "Distribution voltage control utilising the reactive power capabilities of wind generators". *IET Journal of Engineering*, October 2017.

- **D. Danzerl**, S. Gill, and O. Anaya-Lara, "Maximising wind generation through optimised operation of on-load tap changing (OLTC) transformers in active distribution networks". *IET Journal of Engineering*, October 2017

- **D. Danzerl**, O. Anaya-Lara and A. Dysko,"Principles of access techniques for voltage constrained distribution networks". *Energy Policy Journal*, October 2018 - To be submitted

- **D. Danzerl**, O. Anaya-Lara and A. Dysko, "Enhancing wind generation connections: An investigation of novel voltage management techniques in active distribution networks". *IEEE Transaction on Power Systems*, October 2018 - To be submitted

1.8.2 Conference Publications

- **D. Danzerl**, S. Gill, I. Kockar, and O. Anaya-Lara, "Assessment of the last-in-first out (LIFO) principle of access for managing the connection of distributed wind generators". *IET Renewable Power Generation Conference*, London, UK. September 2016

- **D. Danzerl**, S. Gill, I. Kockar, "The effects of principle of access on voltage constraint for distributed generation". *All-Energy Conference*, Glasgow, UK. May 2015

- **D. Danzerl**, B. Leithead, and Y. Hong, "Clarifying the performance of coordinated control for large wind turbine load ". *10th EAWE PhD Seminar on Wind Energy in Europe*, Orleans, France. October 2014

1.9 Structure of thesis

The structure of this thesis follows a similar order to the objectives and key contributions outlined. It reflects the development of the concept and commences with an initial scoping exercise through to the development of fundamental theories and principles that underpins the research.

Chapter 2 provides a background and a review of the research area commencing with a brief overview about the make-up and structure of the GB electricity system. It progresses with an extensive review of academic literature on voltage management techniques traditionally deployed at passive networks contrasting with current active distribution system management. It examines the impact of recent DG proliferation on active networks and control principles implemented to manage voltage constraint.

Chapter 3 introduces the first control strategy which models a time-series active power curtailment method of multiple wind farm connections for distribution voltage control. It presents a real case-study assessment of the principles of access methods for sharing limited network capacity and curtailment among the multiple DGs. An assessment criteria is developed and used to compare the PoA and to qualitatively analyse their effectiveness when applied to voltage constrained networks.

Chapter 4 presents the second voltage control strategy which involves an optimised operation of on-load tap changing (OLTC) transformers on HV/MV networks. The control action developed applies OPF optimisation techniques on a realistic case-study network to test the effectiveness to enhance distribution network hosting capacity to accommodate high wind penetration.

Chapter 5 presents the third voltage control strategy which models the reactive power dispatch capabilities of modern wind turbine technologies. It assesses the wind farm capabilities to mitigate the voltage rise constraint by demonstrating on a case-study network using time-series OPF methods. It examines the power factor control (PFC) and voltage control (VC) modes of operation of variable speed wind turbine technology and discusses practical techniques that enhances greater connection capacities for the wind farms.

Chapter 6 presents the adoption and deployment of the coordinated voltage control (CVC) methods and principle of access (PoA) for voltage constrained networks. The chapter provides an extensive and detailed investigation of the performance of the non-firm wind generators when the CVC and PoA techniques are implemented on a base-case study network. The base-case studies serves as a benchmark to assess the effectiveness of the proposed ANM solution for distribution networks.

Chapter 7 provides a qualitative and quantitative assessment of the wind farm performances and tests the effectiveness of the proposed method under various network operation conditions. It provides a comparative study to validate and evaluate the robustness of the proposed strategy when applied under certain likely changes in future network operation conditions. It explores the potential to reduce further DG curtailment by implementing operational changes such as, relaxing the network constraint limits to provide flexible alternative options that defers reinforcement.

Chapter 8 concludes the thesis and brings together the key point and learning outcomes. This chapter justifies the principal contributions to knowledge listed and answers the key research question. Finally, important future work to this thesis is identified and discussed.

Chapter 2

VOLTAGE REGULATION AND MANAGEMENT AT DISTRIBUTION NETWORKS

2.1 Background

The primary aim of an electricity supply system is to meet customer demands and expectation for electrical energy. It implies the supply of secured, safe and reliable flow of power to consumers at all times. The electricity supply system is required to deliver quality power at stable voltages and levels required by customer electrical equipment. Conventional power supply systems are commonly a three-phase alternating-current (AC) systems characterised by electricity generated from large centrally located power plants and transferred to customer loads through the transmission and distribution networks [21].

In the UK, the electricity supply system consists of large scale generation plants, high voltage (HV) networks, integrated generation, transmission, distribution and supply functions [22]. Figure 2.1 demonstrates the interrelationship of the various networks and voltage levels. The transmission system consists of long-distance bulk network through which electrical power moves at extra high voltages (EHV) from the large centralised generators to a small number of large industrial customers.

Power transmission at high voltage levels is to reduce network losses and promote an efficient power transfer. Typical transmission voltage levels in the UK are 400 kV and 275 kV [23]. In Scotland, voltage levels at 132 kV are considered as part of the transmission network [24]. The distribution network transmits electrical power from the transmission system and delivers to the end user at lower voltages (LV) utilising localised networks.

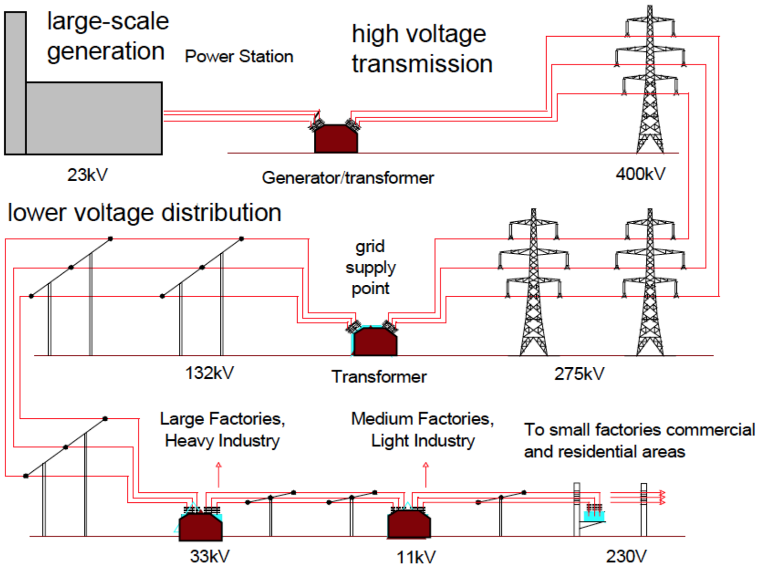


Figure 2.1: UK electricity network [22]

The distribution network voltages are normally maintained at 132 kV (England), 33 kV, 11 kV, 6.6 kV, 400 V and 230 V which are usually domestic supply level. Network voltage variations from the nominal corresponds to power production and demand for electricity. Distribution network operators (DNO's) have responsibilities to regulate and maintain the voltage levels supplied to customers within statutory limits. The network voltages need to remain within a relatively narrow range in order to avoid network equipment breakdown and adverse effect on customer devices. Customer equipments are designed at specific voltage levels and too many voltage violations can result in device malfunctioning and breakdowns [25].

In the UK, the statutory framework and voltage limits are defined in the Electricity Safety, Quality and Continuity Regulations (ESQC) 2002 [19]. It specifies that lower (LV) customers be supplied at 400/230 V with tolerance of +10/-6% whereas high voltage (HV) customers be supplied at 33 kV to 6.6 kV at tolerance of $\pm$6%. In the the UK, the distribution network has its own owners and operators. There are currently 7 licensed distribution network areas in the UK as shown in Figure 2.2 and the DNO's are responsible for maintaining the network asset.

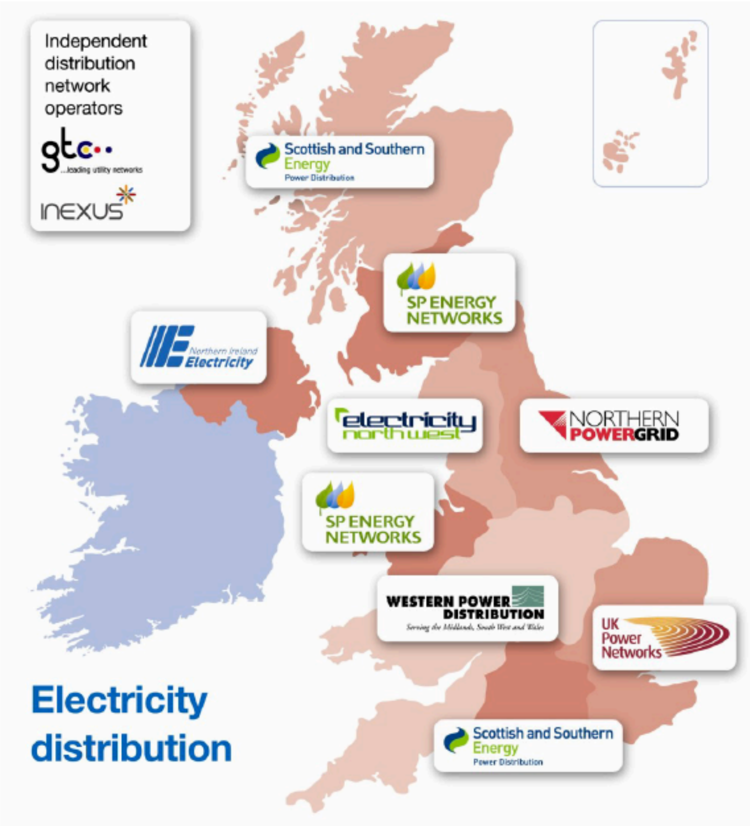


Figure 2.2: Distribution network operators in the UK [26]

2.2 Voltage control methods in passive distribution networks

The utility provider and customer equipment connected to a power network are designed to operate within a certain permissible voltage range to avoid equipment damage and potential human-health risk. The utility provider is tasked and has a responsibility to maintain the network voltages within required limits. For an efficient and reliable operation of the power network, the following control objectives are imperative:

- Maintaining the terminal voltages of the power system components within acceptable limits.
- Controlling reactive power flows and voltages to enhance the power system stability.
- Minimising the flow of reactive power to reduce active and reactive losses.

As electricity generation and demand increases, the requirement to maintain the network voltages within the stipulated limit becomes challenging. On the transmission network, voltage control is achieved by generating units (such as synchronous generators), regulatory transformers (including on-load tap changer transformers), sources or sinks of reactive power (capacitors, condensers and static VAr compensator) and line reactance compensators (such as series capacitors).

The impedance of transmission network components are predominantly reactive, therefore voltage control can be accomplished by managing the production, absorption and flow of reactive power [27, 28]. Synchronous generators can generate or absorb reactive power depending on their excitation, when overexcited can generate VArs and when underexcited they absorb VArs. Network loads including motors and induction generators consumes reactive power as well as active power from the network [29]. Network transmission components such as powered transformers, overhead lines and underground cables can consume and produce reactive power. When fully loaded, overhead lines absorb reactive power. During light load conditions, the shunt capacitances of longer lines may become dominant and high voltage overhead lines then become VAr generators. Transformers always absorb reactive power. Cables are generators of reactive power owing to their high shunt capacitance characteristics under all loading conditions [28] - [30].

In the UK, passive distribution network operations have traditionally been planned in accordance with engineering recommendations P2/5. The standard and operation philosophy was based on rules that ensures security of supply and network planning capacities [31]. The passive operation of the network was designed with an assumption of unidirectional power flows from the transmission system into the distribution network with minimum control and monitoring [32]. In radial distribution network topologies, the voltage profiles were assumed to decrease as we move along the feeders from the primary substation to the remote end of the feeders. The planning and operation regime was such that; the minimum customer supply point voltage was near the lower limit of the permissible voltage range and the maximum customer supply point voltage was near the upper limit of the permissible voltage range.

Automatic voltage regulation (AVR) on the distribution network was mainly achieved through centralised control systems at the primary substation such as; on-load tap changing (OLTC) transformers and reactive power compensation devices. The aim is to keep the steady state voltage stable within an acceptable range at all times that would otherwise vary with the system load variations. There are a number of voltage regulation techniques available for network operators to implement however, the most common methods include [33]:

- Application of voltage regulating equipment at the distribution substations
- Installing reactive power compensation devices (e.g. shunt capacitors)
- Balancing of loads on the primary feeder and the transfer of loads to new feeders
- Building new substations and primary feeders
- Increasing the conductor size of existing feeders.
- Utilising substation transformers with on-load/off-load tap changers.

The choice or selection of a particular technique usually depends on system requirement, cost and planning objectives. The application of reactive power compensation devices such as shunt capacitor and reactor, synchronous condenser and static VAr compensator (SVC) can help meet local reactive loads when the demand is high or can absorb reactive power when demand is low. They can be installed at different locations within the distribution system to ensure the voltages remain within the permitted range. In addition, the location and VAr output of the compensators can be optimised to minimise network losses and improve efficiency [34]. The development of a dedicated substation and primary feeders tend to minimise or alleviate power flow congestions and subsequent voltage constraint issues however, can incur significant investment costs.

Automatic voltage regulation provides direct ways of controlling the voltage and usually consists of bus regulation at the primary substation, individual feeder regulation and supplementary regulation along the feeders. Generally, distribution network HV/MV substations are usually equipped with OLTC transformers that automatically controls the secondary voltages [25]. The control of voltage at the secondary side of the HV/MV transformer can be achieved by altering the transformer winding ratio, by altering the relative length of the HV winding. The OLTC transformer operates by moving their tap positions to select appropriate transformer turns ratio that suits a range of power flow conditions on the network. To simplify and automate voltage control, automatic voltage control (AVC) relays are used in conjunction with line drop compensation (LDC) equipment to ensure that the voltage can be controlled not only at transformer terminals but at a nominal supply point [35]. The AVC relay operates by continually monitoring the network voltages to detect out of range variations and initiates a tap change command to the motorised OLTC when the voltages are outside the pre-set limit [36]. For feeder regulation, step voltage regulators (SVR) are commonly used to boost or step down the voltage along the feeders without altering the nominal voltage.

2.2.1 Voltage control at distribution substation

2.2.1.1 On-load tap changing (OLTC) transformers

Distribution substation transformers are usually equipped with taps in their windings to alter the turns ratio and are often considered the most convenient method to control the secondary side voltages [37]. The control of the secondary side voltages can either be achieved automatically or manually. The OLTC transformer is a discrete mechanical device widely applied in HV/MV substations to frequently change the turns ratios automatically in response to system voltage variations. System voltage variations are triggered by changes in network operation conditions including changes in daily, hourly and minute-by-minute loads and generation characteristics. Therefore, the operation of the OLTC transformer at the distribution substation requires careful planing and setting of the transformer. Optimal power flow (OPF) techniques are providing a convenient method of determining appropriate tap settings [30] of the OLTC transformer operations. The technique is further explored in Chapter 4 of this thesis. The tap changing mechanism of the transformer by altering the voltage magnitude affects the flow of VArs and therefore can also be used to control reactive power flows in the system.

The OLTC transformer is usually equipped with AVC relay commonly referred as the brain of the system [38], controls the tap changing mechanism of the transformer. Figure 2.3 demonstrates a basic arrangement of distribution substation voltage control with OLTC transformer and AVC relay.

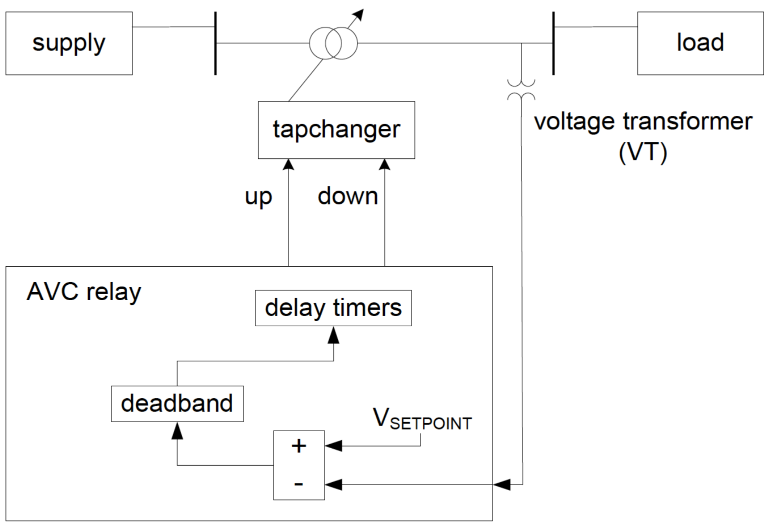


Figure 2.3: Basic arrangement of an OLTC transformer with AVC relay [39]

At its simplest arrangement, the AVC relay operates to keep the secondary side of the substation voltage constant. As stated earlier in this section, the tap changer is a discrete component, hence a dead-band (DB) is required to avoid hunting effect of the tap changing mechanism. The AVC relay operation usually incorporates a time delay setting between 10 to 120 seconds from detecting an out of range voltage and initiating a tap-change command [21]. The time-delay setting is to avoid unnecessary tap operation during short-term voltage fluctuations on the network and also to avoid excessive wear on the tap changer [40]. The AVC relay operates by monitoring and comparing the measured substation voltage and the reference voltage $V_{SETPOINT}$. If the measured voltage exceeds the preset deadband (DB) after a specific time delay, a tap changing command is sent to the OLTC transformer [38] - [41]. The tap position alters accordingly so that the transformer secondary side voltage can be regulated back to the preset limit.

2.2.1.2 Automatic voltage regulation using line-drop compensation (LDC)

An OLTC transformer is normally provided with line drop compensation (LDC) equipment which operates to keep the voltage at some remote location on the network constant. The LDC is used to compensate for voltage drops on the line between the transformer and the loads situated toward the far end of the feeder. The adoption of LDC methods in passive distribution networks allows the operation of the OLTC to control the voltages without the need for communication systems. A general schematic arrangement of OLTC transformer with LDC is shown in Figure 2.4.

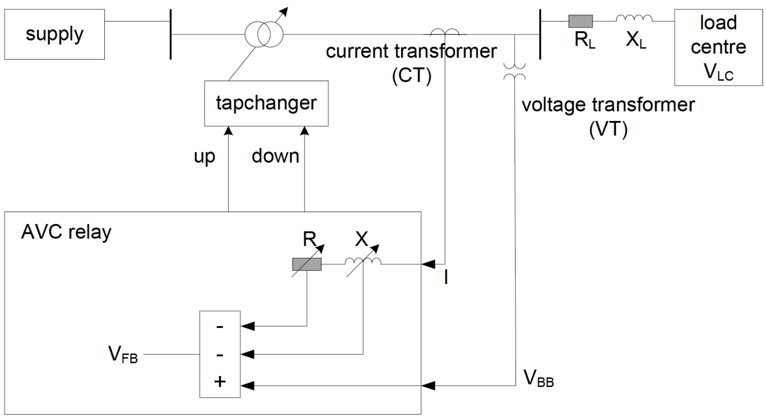


Figure 2.4: Key elements of line drop compensation [39]

The LDC monitors the busbar voltage V_{BB} at the secondary side of the transformer and then uses a measure of the flowing secondary current I to simulate the voltage drop across feeder that exists between transformer and the load. Figure 2.5 shows the corresponding phasor diagram.

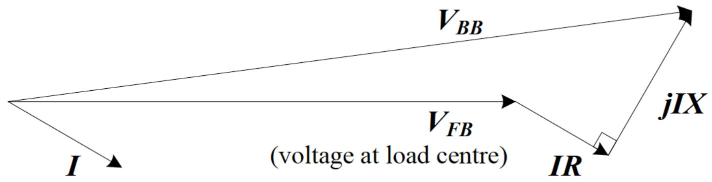


Figure 2.5: Phasor diagram of line drop compensation [39]

The values of R and X inside the relay are used to simulate the real impedance $R_L + jX_L$ of the line. The LDC then performs a voltage correction at the substation to compensate for variation in the MV-feeder voltage drop. The LDC estimates the line voltage drop based on the line current I and impedance values $R_L + jX_L$ inside the relay to perform the voltage correction to get V_{LC} within a certain maximum and minimum range defined in equation 2.1.

$$V_{LC}^{min} \leq V_{LC} \leq V_{LC}^{max} \tag{2.1}$$

Thus, the feedback signal V_{FB} corresponds to the real voltage at the load centre V_{LC}. By doing this, the substation voltage can be controlled for all loading conditions [38]. Properly adjusting the impedance values $R_L + jX_L$ to the turns ratios of the current transformer (CT) and potential transformer (PT) yields equations described in equation 2.2 and equation 2.3 [42].

$$R = \frac{N_{CT}}{N_{PT}} R_L \tag{2.2}$$

$$X = \frac{N_{CT}}{N_{PT}} X_L \tag{2.3}$$

where;

R and X are the LDC settings for the resistive/reactive compensation, N_{CT} is the turns ratio of the current transformer, N_{PT} is the turns ratio of the potential transformer. The voltage at the load centre during minimum and maximum loading conditions can be approximated as:

$$V_{LC}^{max} = V_{BB}^{max} - I^{max}(R_L \cos\phi + X_L \sin\phi) \tag{2.4}$$

$$V_{LC}^{max} = V_{BB}^{min} - I^{min}(R_L \cos\phi + X_L \sin\phi) \tag{2.5}$$

In network applications where several transformers are connected in parallel, the basic AVC relay operation becomes inadequate as it eventually leads to tap divergence due to tolerances of the components. Three techniques are commonly used: master-follower, true-circulating-current and negative-reactance compounding as stated in [39] and [43]. A master/follower arrangement can be used whereby, following a tap change by the master transformer tap change, auxiliary contacts on the tap changer automatically initiates a similar tap change on the follower transformer(s). A preferred arrangement detects the circulating currents, which arises when transformers in parallel are on different taps to initiate the appropriate tap change in order to ensure that all transformers are maintained on, or near, the same effective tap [21].

2.2.2 Feeder voltage regulation

Primary distribution network substation consist of one or more primary feeders or laterals where a number of sublaterals or branches are tapered off [44] before reaching consumer supply points. In the case of long radial feeder topologies, global system voltage control at the primary substation may not be sufficient to keep the network voltages within acceptable limits. The voltage profile shown in Figure 2.6 shows the voltage drop along the feeder when no voltage regulation devices are installed along the lines.

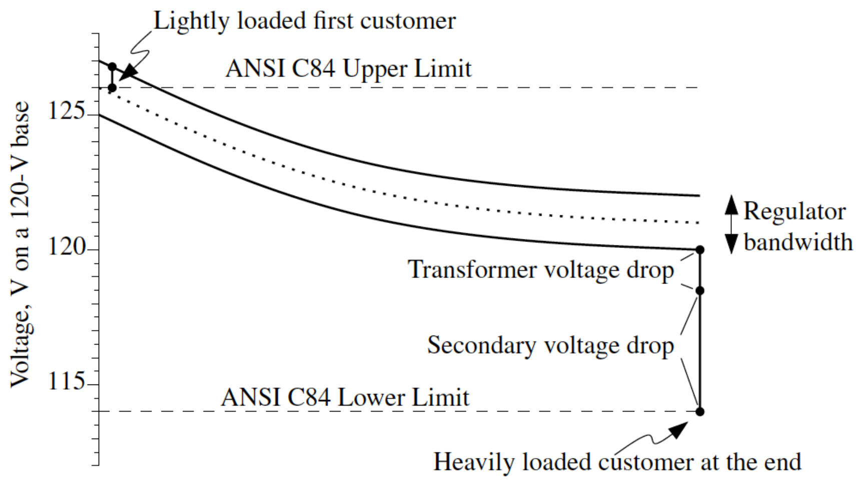


Figure 2.6: Voltage drop along radial feeder with no in-line regulation [45]

Customers connected to the far end of the feeder may experience undervoltage supply during heavy load conditions and can cause major equipment damage. Conversely, customers connected at the upstream point (near the source) of the feeder may experience overvoltage supply above the stipulated 126 V during light load conditions. As a result, feeder voltage regulators are commonly used to regulate and maintain a constant voltage at the point of utilisation. Modern distribution network systems consists of step-type voltage regulator (SVR) which can be either *station-type* or *distribution type*.

The *station-type* can be single-or-three-phase which can be used at substations for bus voltage regulation (BVR) or individual feeder voltage regulation. The *distribution-type*, can only be single-phase and pole-mounted on overhead line primary feeders [44]. The SVR is fundamentally an autotransformer with many taps or steps in the series windings [46, 47]. Conventional SVR's are designed to correct the line voltage through a buck or boost process with their load-tap changer mechanism without changing the nominal voltage [30]. The SVR provides voltage regulation range from -10% to $+10\%$ with 32 tap steps [45]- [47]. Voltage change is achieved by varying the taps on the series winding of the autotransformer. A schematic of a basic SVR arrangement is shown in Figure 2.7.

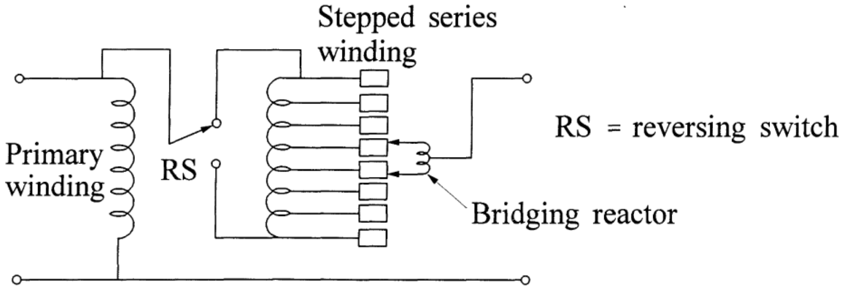


Figure 2.7: Schematic of a step voltage regulator [30]

The SVR is purely a voltage control device and usually not involved in network voltage transformation. Depending on the polarity of the series winding, the voltage introduced in the series windings is either added to or subtracted from the primary voltage. A reverse switching mechanism is provided to change the polarity. The output voltage magnitude of the series-winding is varied by changing the tap position, which can be performed under load conditions. The step-voltage regulator control have regulating relays that controls the tap changer and the circuit requires the following settings:

- *Set voltage*: Also referred as the set-point or band-centre, is the desired output of the regulator.
- *Bandwidth*: Voltage regulator controls monitor the difference between the measured voltage and the set voltage. Only when the difference exceeds one half of the bandwidth will a tap change start.
- *Time delay*: This is the waiting time between the time when the voltage goes out of band and when the controller initiates a tap change. Longer delays reduces the number of tap changing operations and typical values ranges between 10 to 120 seconds.

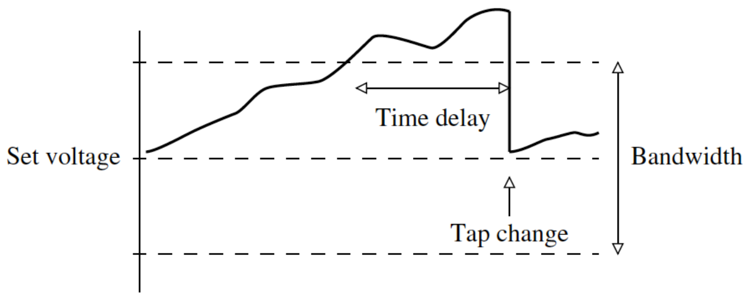


Figure 2.8: Step voltage regulator tap control settings [45]

The three primary control settings discussed are also elaborated in Figure 2.8. The control mechanism of the SVR also provides the ability to adjust line-drop compensation by selecting the resistance and reactance settings [33]. A schematic of the SVR control mechanism in conjunction with LDC is shown in Figure 2.9. The SVR is set to hold a constant voltage (within a certain narrow range) at the secondary side or at some selected point out on the feeder as determined by the LDC impedance R and X values. The voltage sensor compares the input voltage to a preset voltage level. At conditions where the input voltage deviates from the set-point beyond the bandwidth, the tap-changing motor operates the tap-changing mechanism in a direction to restore the voltage within the narrow range. The time-delay settings prevents the regulator from responding to temporary voltage variations.

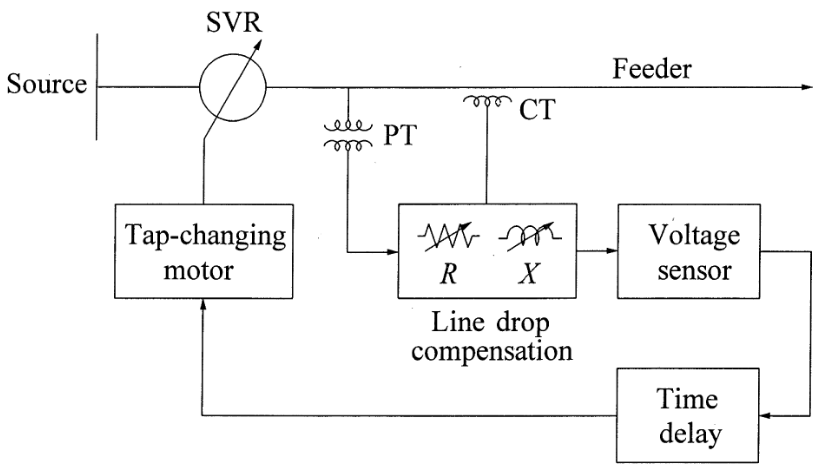


Figure 2.9: Step voltage regulator control mechanism [30]

In network configuration where the feeders are very long, additional regulators and shunt capacitors located at selected points on the feeder provides supplementary regulation. One regulator can be placed at approximately at about one-fifth the distance from the station end. Shunt capacitors can also be used together with the SVR to offer feeder voltage regulation.

2.3 Voltage control methods in active distribution networks

Traditionally, the distribution network have been managed passively with minimum control, monitoring and visibility. Bulk power was delivered outwardly from large centrally located generators through the transmission and distribution systems at higher voltages before reaching consumer suppliers at lower voltage levels. The planning and operation principles assumed unidirectional power flows and uncontrollable resources from the transmission system through to the distribution networks at the various grid supply points (GSP) [48]. Conventional voltage control methods in radial distribution networks (without DG connections) assumed a uniform voltage decrease as power flow outwardly in one direction towards the end of the feeders. Voltage drops are due to line impedances and system load variations.

Nowadays, recent growth in the amount of decentralised and dispersed generation have steered new directions on how the network is managed and operated. The integration of distributed generation units fundamentally alters the dynamics of the network [7] as power flows are bidirectional [49]. The distribution network has become an active system with power flows and voltage profiles determined by a mix of centralised and distributed generation. The modern electrical power network with distributed generation integration is further elaborated in Figure 2.10.

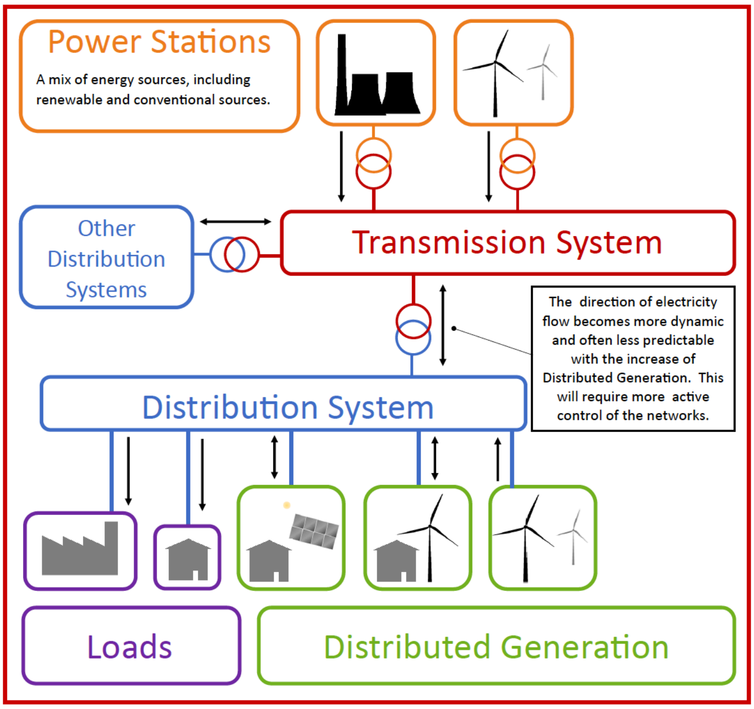


Figure 2.10: Modern electric power system with distributed generation [50]

With increased penetration of DGs, localised overvoltage can occur, where the voltage at the load end may be greater than the voltage at the supply side. This phenomenon is known as the voltage rise effect [51] and can result in reverse power flows back up the network. Voltage rise effects on the other hand have become a major factor limiting greater penetration of DG connections, particularly at weak and rural distribution networks. The magnitude of voltage rise issues on the network depends on the number of DG connections, strength of the network to accommodate the generators (network capacity) and system load conditions. Figure 2.11 demonstrates the voltage rise effect in radial distribution networks with a single DG unit connection.

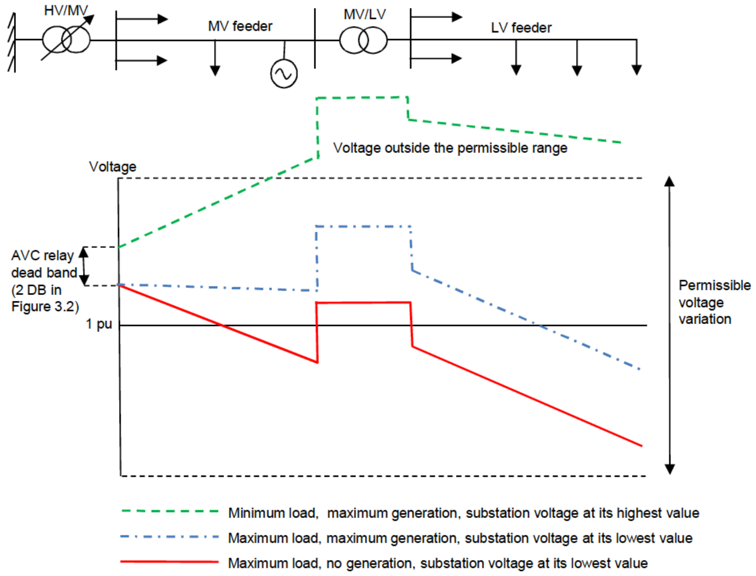


Figure 2.11: Voltage profile of a radial feeder with DG connection [7]

The voltage profile on the MV feeder shows significant changes in characteristics when a single DG unit is connected to the network. At minimum load maximum generation conditions, it is seen that the maximum voltage magnitude recorded at the point of DG connection exceeds the maximum upper limit. This violation in network limits due to voltage rise effect from DG power injections becomes unacceptable. At maximum load maximum generation conditions, the DG unit enhances the voltage and the voltage profile falls within the preset limit with no violation due to changes in demand. At maximum load no generation conditions, the voltage profile shows smooth voltage decrease along the length of the feeder.

Distributed generators in the UK are presently not allowed to participate in voltage regulation activities on the networks other than reducing their active generations. They are often considered as negative loads due to their tendency to absorb reactive power from the network to maintain their terminal voltages. At the planning stage, the amount of generation that can be connected to the network are usually established through deterministic load flow studies, using worse-case scenario of minimum load maximum generation conditions [52]. This passive approach guarantees safe operation of the system within statutory limits and compliance with contractual obligations.

The current planning philosophy adopted by the DNOs is as a result of limited network hosting capacity to accommodate high DG penetration levels. The DNOs manage their network conservatively by constraining the generators wishing to connect, minimising the economic viability for future investment. An alternative to the voltage constraint problem is via network reinforcement. This is usually achieved by increasing the conductor sizes or connecting the DGs on a dedicated feeder. The benefit of this kind of planning practice is that, the network operational principles are maintained and additional network hosting capacity released. The downside is that, reinforcing the network or building a dedicated feeder can in many cases lead to high connection costs for the DGs and can affect the economic viability for the generators.

Maximising DG connection capacities and economic viability requires pragmatic changes and a move away from the previous passive regime towards an active distribution system. It is also a requirement if the capacity of distributed generation is to be increased beyond the firm limit. This can be achieved by intelligently controlling the existing active resources such as DG units, controllable loads, reactive power compensation devices, energy storage units and tap changers of HV/MV transformers.

The advent of active network management (ANM) technologies are offering a feasible solution in this direction in developing an efficient, flexible and reliable networks. For voltage management, it involves the real-time monitoring of the voltage at various locations on the network and the setup of control systems to take actions to mitigate out-of-limit voltage variations. Active network management is defined as the control of power, voltage and frequency within a network through the use of remote control and communication technologies [53,54]. Active network management technologies provides an alternative solution to investing in traditional network upgrades or installation of traditional power system equipment including capacitor banks, or new transformers. In [32], active management of distribution network is described as the preferred option to the connection of renewable or DGs in the UK. By implementing active network management solutions, DNOs can make better use of the existing network capacity through active control of connected generation and other resources.

In this section, we look at how the voltage rise issue can be effectively controlled using ANM techniques. The approach does not necessarily require major investments on primary network components like conductors and transformers but optimally utilises the existing network capacity. Investment on secondary network components including local controllers, network management systems and communication devices may be required. On the contrary, the benefits brought by ANM technologies will very likely outweigh the costs of the secondary network components [55]. The following three key active voltage control strategies are discussed:

- Active power generation curtailment
- Reactive power management
- On-load tap changer transformer

2.3.1 Active power curtailment

Active power curtailment of DG units or shedding can be applied to minimise the voltage rise issues at distribution networks. This type of control can be particularly effective for intermittent generators connected at the weak sections of the distribution network [49]. Low demand conditions can lead to voltage rise issues at the generator POCs. When such conditions occur, the network operator can instruct the DG units to reduce their active power output to levels that maintain the constraint. This option allows the generators to keep operating rather than being disconnected completely from the network. The generators are allowed to increase their active power output again during normal or heavy load conditions.

This approach offers operational benefit to the generators of being curtailed for a short period of time than otherwise denied complete access to the network. In [56], active power curtailment is highlighted as an essential technique for calculating available network capacity for new generators wishing to connect to constrained networks. However, excessive active power curtailment of the DGs discussed in [57] does not fully maximise the benefit of wind integration and is one of the major focus of this thesis.

2.3.1.1 Non-firm contracts and principles of access (PoA)

The traditionally operated distribution networks have strictly limited capacities to accommodate large penetration of distributed renewable generation. This limit is defined by the ability of the distribution network to securely manage the output of all distributed generation during the worst-case scenario with no interventions. The maximum capacity of *firm* generation on a distribution network that is; generation that is guaranteed network access at all times [32] is defined as the maximum injection of power that can be accommodated during minimum demand without breaching network constraint limits (voltage and thermal limits) [58].

On a constrained distribution network, one method of implementing curtailment is by offering *non-firm* contracts. In [32], the authors define *non-firm* contract as one which does not provide *firm* network access at all times. With multiple *non-firm* DG connections, the rules defining which generators receive priority access to a constrained network must be laid out in a principle of access (PoA) which defines the commercial arrangement. The commercial framework for allocating limited network capacity in ANM schemes has been characterised by [59]. In the context of high levels of renewable integration in distribution networks, PoA for wind generators is a relatively new field of research and one likely to play an important role in future ANM schemes [60]. The prevailing PoA for managing thermal constraints on the GB distribution network is a last-in-first out (LIFO) arrangement [61, 62].

This method requires the most recently connected DG unit to curtail it's active power output first during a network constraint. If further curtailment is required the second generator reduces it's output and then it follows in succession until the constraint is relieved. The LIFO arrangement defines a priority stack that governs generator access to available network capacity in real-time and specifies the manner in which to curtail the non-firm generators. This arrangement is seen as simple, straight forward to implement and understand as it fixes network access rights for each generator at initial stages of DG investments (later connecting generators do not impact on the level of curtailment experiences by existing generators). However, LIFO is not the most economically efficient and attractive option for connecting DGs [60, 63].

In [59], the following commercial arrangements are discussed:

- ***Last-in-First Out (LIFO)*** - This method defines the priority order in which generators connect to the network and is based on the date of DG connections. It involves a successive scheduling of curtailment behind the non-firm generators (NFGs) when the network lines are congested, with the highest amount of curtailment suffered by the last generator to connect to the network. As noted in [59] and [64], adding new generator connections to the LIFO priority list (in the position of least priority) does not alter the priority position of existing generator units with non-firm contracts. The existing non-firm generators are immune against future curtailment. The approach offers significant operational benefits including transparency, consistency and easier implementation with current regulations when compared with other arrangements. However, as noted by the authors in [65], the method is unlikely to lead to maximising the capacity of distributed generation output as late connections will receive very restricted network capacity. Furthermore, when applied to DGs managed under voltage constrained condition, it can lead to underutilised network capacity [66].

- ***Pro Rata*** - The Pro Rata arrangement initially assesses the curtailment required on the network and then splits it equally between the non-firm DGs contributing to the constraint. The total curtailment required is shared by each of the generator units based on the ratio of their rated output to the total required curtailment. This method ensures and has the advantage that curtailment is shared equally and that no one generator is excessively constrained. A major benefit of this method is that, it is more likely than LIFO to lead to maximum viable capacity connections. Also, implementing this method would not require a change of regulation and would grant fair access to multiple DG connections. It satisfies the competition goals of the regulator and could encourage more new generation to connect when compared with other methods. However, it is difficult to assess the long term impact of this method, as more DGs connect to the network leading to increased curtailment to be experienced by the existing generators. This uncertainty in future network access is likely to be a deterrent to investment. One approach to resolve this is by setting a cap on the level of generation which can be connected behind a particular constraint.

- ***Rota*** - This principle of access arrangement curtails the non-firm generators based on the order specified in a predetermined rota. The rota schedule could be alternated on a daily, weekly or monthly basis at the network operator's discretion. Under this circumstance all the generators are treated equally, however careful consideration should be given to the frequency of the rota arrangement. Also, as the level of generation connected under a rota arrangement increases, the level of curtailment may increase however the length of time spent at the bottom of the priority stack would decrease. This uncertainty could be eased if the DNO were to set a cap on the amount of generation that can connect to the network, thus calculating a minimum capacity factor that each non-firm generator might experience.

- ***Market Based*** - Under a Market Based principle of access method, a curtailment market is used to determine the curtailment order of non-firm generation. The non-firm generators could pay for access to the network for a period and capacity allocated to those offering the highest payment. Alternatively, generators may offer a price to be curtailed with a market mechanism to proportion curtailment accordingly. Network capacity here, is considered as an economic good of limited supply. This type of arrangement places more control in the hands of the generator over the issue of enforced curtailment and is likely to find favour within the current climate of liberalised energy markets. On the contrary as highlighted in [59] and [60] it may be too complex to implement in relatively small scale distribution networks and may require significant changes in distribution network codes and the creation of a new market system.

- ***Most Convenient*** - This method allows the system operator to curtail the generator they know to be the most convenient to respond to the network constraint. The assessment for relieving the constraint is influenced by the system operator's preference. This may lead to unfair discrimination against certain types of generators based on location and size. For instance under voltage constraint conditions, remotely located generators connected to the weak parts on the network will suffer severe curtailments and unfairly discriminated when compared to DGs connected to a strong or medium sections of the network.

- ***Technical Best*** - This principle of access allows the network operator to define the best way of dispatching the network functioning under the current conditions and to impose that solution on generators. The definition of technical best may include maximisation of generation capacities, minimisation of system losses or most secure operation of the network. This principle of access method has the advantage of providing strong signals to developers as to where to develop. Here, generator connected in a location that is often technically bad is likely to receive high levels of curtailment.

2.3.2 Reactive power management

Reactive power is the power within an AC system which does not do useful work at the loads and is due to the phase difference between the voltage and current. Reactive power forms a major component of the full AC power flow. At present, transmission systems employ synchronous generators, capacitors, reactors, synchronous condensers, Static VAr Compensators (SVCs) and Static Compensator (STATCOMS) to control the reactive power flow. Synchronous generators are frequently used to produce or absorb reactive power depending on network load conditions. Reactive power compensation devices may be installed at substations or on long transmission lines to enhance the voltage and reactive power flows [67].

The use of reactive power compensation devices is a useful method for regulating distribution voltages. Absorption of reactive power can be employed to control voltage rise effects, particularly in weak overhead lines. Conventionally, distribution networks have been operated with capacitor banks to keep the power factor close to unity and to compensate for voltage drops during heavy loading conditions. Reactive power support on distribution networks is also provided by external resources including SVCs or STATCOMS inverters which can be adjusted automatically to control the local voltage. The Static VAr Compensator (SVC) consists of an integrated system made up of static electrical components including switches, capacitors, reactors and transformers combined together to provide rapid, continuously controllable shunt VAr compensation [68].

These inverters are very fast in response to changes in power system voltages [14]. The inverters are useful in areas with rapid changes in voltage due to large load transients (e.g. motor starts) or where only a small range of VAr control is required . The technique is a local mode of control and generally does not require communication systems. Two commonly used reactors are mainly, thyristor-controlled reactors (TCRs) and thyristor-switched capacitors (TSCs) [69–71]. The STATCOM operational principle is based on a voltage-sourced converter which are usually connected in parallel to the power system through a series inductance [72, 73]. STACOMs usually provide a better reactive current support for systems with severely reduced voltages with response times between $0.01-0.04s$ when compared with SVCs which are usually between $0.02-0.06s$ [30]. An illustrative example of an SVC and STATCOM topology is provided in Figure 2.12.

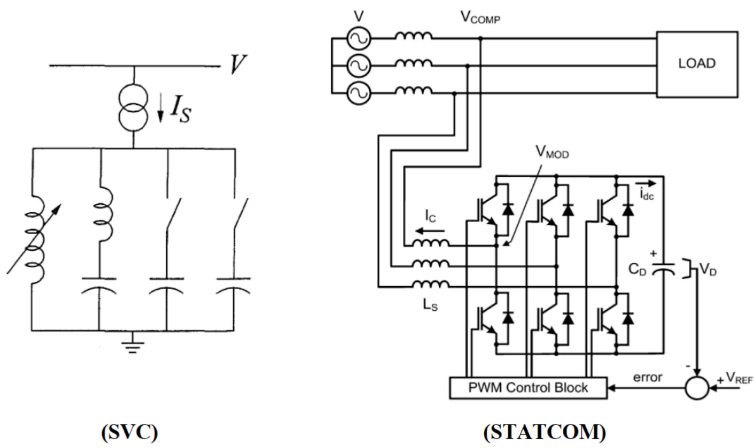


Figure 2.12: Example of SVC and STATCOM arrangement [30, 68]

Reactive power can be provided by synchronous and induction machine based DG units that are able to adjust to the system's voltage variation and reactive demands.

The reactive power output of a synchronous generator is determined by the direct current (DC) flowing in the field windings of the rotor i.e. the excitation current. The reactive power output of an induction based generator is dependent on the real power output and there exists a relationship between real and reactive power outputs. Reactive power can be absorbed or injected by modern DGs units through their power electronic interface which is connected in parallel to the distribution network. Distributed generators are normally treated as a source of real power and a result their reactive power capabilities are often ignored. The implementation of such capabilities to control voltage rise issues to enhance DG generation capacities is an emerging technology and one that has not been widely applied in the UK.

In the early stages of renewable generation development, wind turbine design was based on induction generators which operated at or near fixed power factors with no control over reactive power. Induction generator based wind turbines operated at fixed rotational speed and as such was not optimal in transforming wind resource into electricity. However, recent development over the past decade have seen an increased growth in modern wind turbine technologies operating at variable speed through a Doubly-Fed Induction Generator (DFIG) or a Fully-Rated Convertor (FRC) systems. A typical configuration and topology of wind turbine generator types are shown in Figure 2.13.

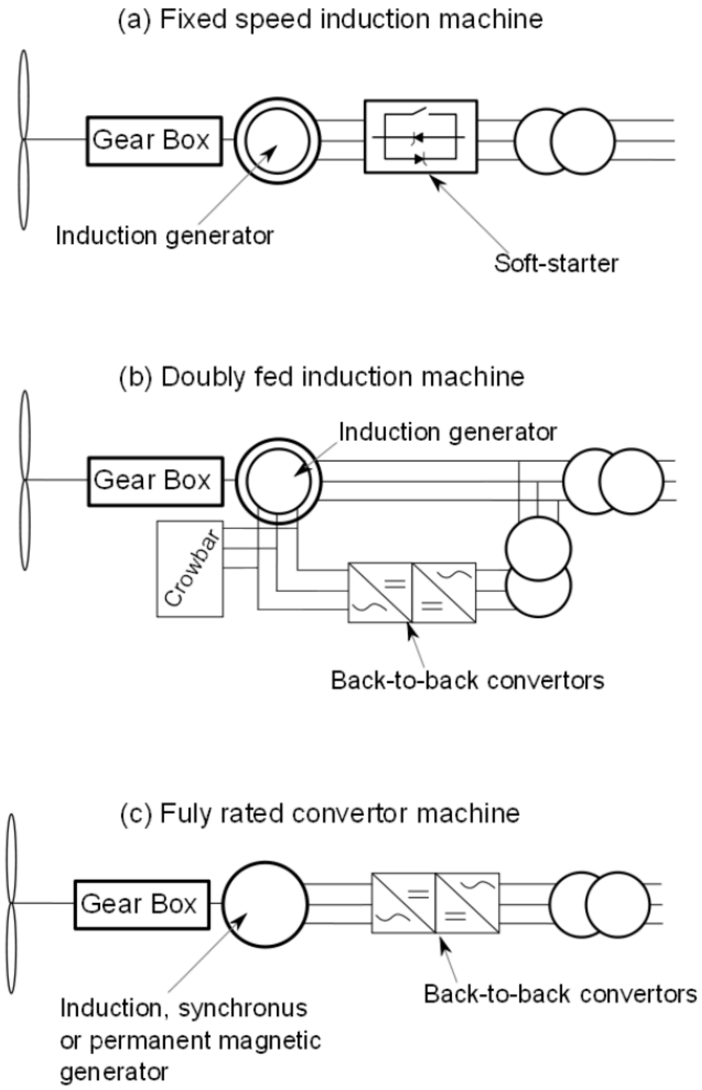


Figure 2.13: Summary of wind turbine generator configuration [74]

In the case the DFIG configuration, it uses a wound rotor induction generator with slip rings to take current in or out of the rotor winding and variable-speed operation is obtained by injecting a controllable voltage into the rotor at slip frequency. A DFIG system can deliver power to the grid through the stator and rotor. The DFIG generator can also absorb reactive power through the rotor. This phenomenon and mode of operation is dependent on the rotational speed of the generator. The doubly fed induction machine can provide between reactive power support between 0.5 and 1 per unit depending on the real power output. In the FRC configuration, the power converter system consists of the grid-side and the generator-side converters connected back-to-back through a DC link. The grid-side converter is a pulse width modulated-voltage source converter (PWM-VSC), and the generator side converter can be a diode-based rectifier or a PWM-VSC. A fully-rated convertor based machine can technically be able to provide full 4-quadent power control operating up to its rated apparent power at any power factor through the power electronic interface.

Recent advancement in modern wind turbine technology equips the generators to participate in voltage control and reactive power support on the network. At the point of connection with the network, the wind generators can operate within their reactive power capability limits and switch between voltage control(VC), reactive power(RPD) dispatch and power-factor control (PFC) modes to control the system voltage. A number of wind turbines active network management studies in these context have been presented in [48], [75–77]. The authors in [78] discuss power factor control of distributed wind generation in terms of their ability to increase distributed wind capacity that can connect to a particular distribution network. The study implements a multi-period optimal power flow (OPF) analysis by combining the operation of power-factor control (PFC) of distributed wind generation, coordinated control of on-load tap-changing transformers and generation curtailment.

2.3.3 On-load tap changing transformer

Passive distribution networks have traditionally been characterised by unidirectional power flows where voltage control is undertaken at the primary substation using compensation devices such as on-load tap changing (OLTC) transformers and line drop compensators. Even though this technique for voltage control is well established, traditional AVC schemes can be unreliable particularly when the transformer arrangement is complex with high variability in network conditions [79].

In active distribution networks with multi-directional power flows, this method of voltage control practice becomes inherently inadequate due to changes in network dynamics and complexities as a result of growing amount of DG connections [14].

Operational challenges such as reverse power flows from the DGs and varying power factors in current active distribution systems adversely affects the operation of OLTCs to efficiently regulate and maintain the voltages [80]. Weak distribution networks particularly, rural networks with low X/R characteristics are highly susceptible to voltage rise problems when various DG resources are connected [81]. Power generations from intermittent renewable resources such as wind and solar compounds the challenge and undermines the performance of the OLTCs to efficiently regulate the voltage. These complexities have rendered conventional OLTC transformers alone, inefficient and unreliable to control the voltage, limiting DG connection capacities on the network. The restrictions placed on generator capacity by present network design practice can be overcome if a more active approach to network voltage control is adopted.

2.3.3.1 The SupperTAPP n + Voltage Control Relay scheme

In references [79] [82], the SuperTAPP n+voltage relay scheme has been introduced to control the network voltage in the presence of DG connections and varying load conditions. One of the key benefits to this scheme as mentioned in [79] is that, all measurements are taken locally and as such there's usually no requirement for remote communication with the generators. Figure 2.14 shows a systematic arrangement where the SuperTAPP n+ relay controls two parallel OLTC transformers.

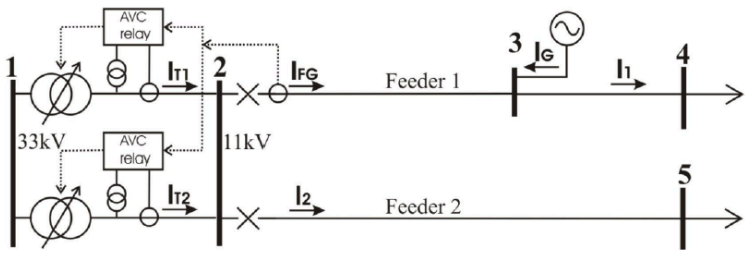


Figure 2.14: SuperTAPP n+voltage control relay arrangement [79]

The innovative technique employed in the SuperTAPP n+ relay is the ability to estimate output of the generator which is connected at some remote point on the feeder. The estimation of DG current I_G is achieved by the additional current measurement I_{FG} on the feeder with DG and ratio E_{ST} which represents the load share between feeders with embedded generation to those without generation.

$$E_{ST} = \frac{\text{Load on feeders with generators}}{\text{Load on feeders without generation}} = \frac{I_1}{I_2} = \frac{I_{FG}}{I_{TL} - I_{FG}} \tag{2.6}$$

The ratio E_{ST} is estimated prior to the connection of the generators or when generation output is zero, resulting in $I_G = 0$ and $I_{FG} = I_1$. The sum of the transformer current can be represented as:

$$I_{TL} = \sum_{n=1}^{N} I_{TN} = I_{T1} + I_{T2} \tag{2.7}$$

The generator current I_G can be determined as:

$$I_G = (E_{ST}(I_{TL} - I_{FG})) - I_{FG} \tag{2.8}$$

With knowledge of the generator current output I_G, the voltage rise at the point of DG connection can be calculated and appropriate generator compensation bias (buck) be applied to the AVC. The generator compensation bias is calculated in reference to the voltage rise at the maximum generator current I_{Gmax} as shown in the equation below:

$$V_G = V_{Gmax}\% \frac{I_G}{I_{Gmax}} \tag{2.9}$$

This value corresponds to the necessary voltage settings at the substation in order to bring the voltage level at the point of DG connection within statutory limits. This method has additional advantage of improving the performance of the LDC. With accurate LDC settings, adequate voltage profile of heavily loaded network with significant penetration of DG can be maintained. Also with the appropriate settings of the generator compensation bias, locations where DG causes unacceptable voltage rise can be controlled. The SuperTAPP n+ scheme can significantly improve the voltage profiles of heavily loaded networks with significant penetration of DG as well as resolving the issues associated with the voltage rise effect at DG point of connection. The scheme is a cost effective solution that provides adequate voltage control in distribution networks.

The drawback of the SuperTAPP n+ relay scheme is that it requires current measurements for each feeder with DG. This may increase the control costs and response time when there are multiple feeder connections with more than one DG. Frequent changes in network conditions may increase the complexities and undermine the performance of the SuperTAPP n + relay scheme.

2.3.3.2 Effect of variable wind resource on transformer tap operations

Power output from wind turbine generators are stochastic in nature and may introduce power flow fluctuations at the distribution substation transformers. The high variability in power flows may ultimately lead to an increase in the frequency of tap changing operations of the HV/MV transformer leading to high maintenance cost and reduced life-span. The analysis and effect of variable wind resources on transformer tap-changing operation have been presented in [84]. Results from the study indicate that, wind power variation significantly increase the number of tap change operations decreasing the life-span of the transformers.

Fluctuating power output from the intermittent generators interferes with the voltage control devices on the network and can make voltage management particularly difficult for network operators. This issue is further explored in Chapter 4 of this thesis, where the tap change operations of the OLTC transformer is formulated as an optimisation problem. To reduce the frequency in the number of tap change operations of the OLTC transformer, a control algorithm utilising the reactive power compensation from wind turbines has been proposed in [85]. The results show that, reactive power compensation can be used effectively to reduce the frequency in tap changing operations.

2.4 Coordinated voltage control at distribution networks

The purpose of voltage control in distribution networks is to compensate for load variations, such that customer supply voltages are kept within certain bounds. The traditional method for controlling voltage across a passive distribution network is by incorporating on-load tap changing (OLTC) transformers and switched shunt capacitors which are controlled based on local voltage measurement at the substations [44], [86,87]. Local voltage control at passive distribution networks operated with the assumption of unidirectional power flows with the voltage decreasing smoothly along the feeders [88]. In this regime, there were no coordination between the control equipments for the various voltage levels and the voltage profiles were far from optimum.

The introduction of communication systems which comes with active network management (ANM) technologies, allows the control of transformers and other voltage regulatory devices in response to system voltage variations. This scheme is referred as coordinated voltage control (CVC) and is an emerging technique in line with recent modernisation of distribution networks. Here by involving the DGs, a good coordination between the voltage control equipments can achieve optimum voltage profiles on the network [48]. For example, a coordination between the DGs and other voltage control devices can result in significant reduction in the number of tap changing operations of the OLTC transformer [89]. By involving DGs in CVC, voltage control at distribution networks will be similar to techniques employed in transmission networks where voltage control is deployed in three hierarchical levels. The primary control will be performed by the DGs which will operate to maintain the terminal voltages at the set-point values, with response times faster than one second. The secondary control will be performed by locally operated OLTC transformers and switched capacitors with response time of about one minute. Tertiary control will be performed by remotely adjusting the DGs, OLTC and capacitors, if required, in order to obtain an optimum voltage profile [90] with response times varying between 10 to 30 minutes. Figure 2.15 presents a conceptual design of a coordinated voltage control arrangement studied in [88].

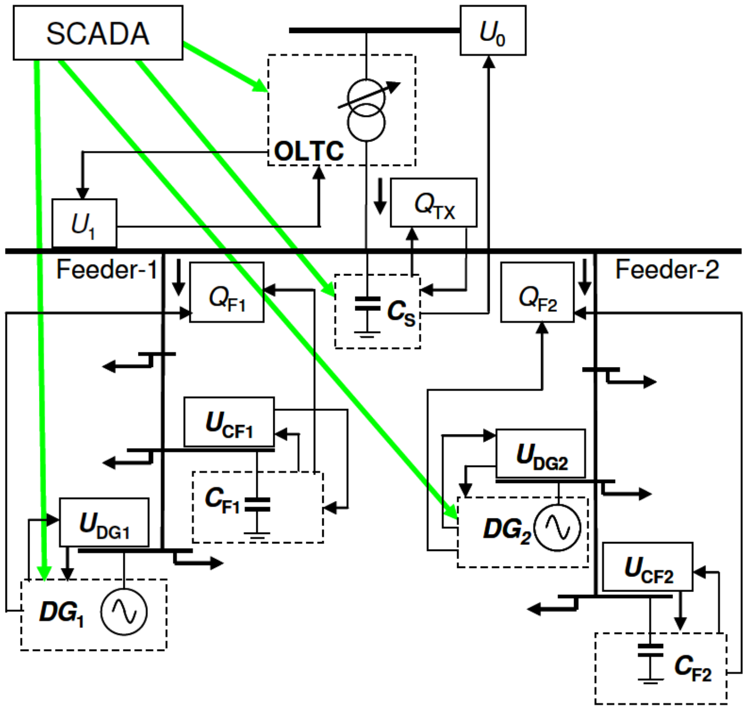


Figure 2.15: Schematic of coordinated voltage and reactive power control in the presence of DGs [88]

Here, the coordinated voltage control technique adopted refers to both local and remote operation of voltage and reactive power control equipment adjustments based on a wide area coordination. The adjustment equipments are OLTC, capacitors and DGs intended to obtain an optimum voltage profile and reactive power flow according to a given set of objective function (losses minimisation and maximum utilisation of shunt capacitors), for a day ahead load forecast and DG output planning. The SCADA system collects measurements from strategic points in the network and sends this data to the distribution management system. The distribution management system determines what actions are required based on the collated data and information.

Coordinated control of substation voltage can be combined with local reactive and real power control. In [49], a scheme is investigated which controls the on-load-tap-changing transformers using remote voltage measurements. The scheme is known as area based coordinated voltage control and is combined with generation curtailment and reactive power dispatch capabilities of the wind generators with aim to increase the level of distributed wind generation connections in ANM. The work shows that area based control can significantly enhance generation capacities for the non-firm generators.

In [91], a coordinated control of the generator automatic voltage control (GenAVC) scheme is proposed as an effective solution to increase network hosting capacity for DGs (by 50%) and to maintain the voltage profiles within specified limits. The GenAVC controller project was developed by Econnect Ltd to manage power system voltages in the presence of DGs. The GenAVC is an active network management device that can regulate the voltages on 11 kV distribution networks. The system provides a cost-effective voltage regulation by implementing state estimation techniques to regularly calculate the voltages throughout the 11 kV network. The objective of the scheme is to maximise generator output while managing network voltages [92]. Figure 2.16 illustrates the measurements and control loops required by the GenAVC.

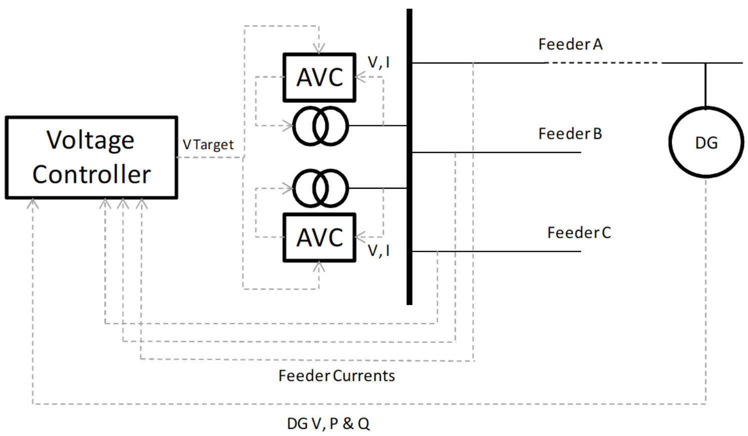


Figure 2.16: Schematic of GenAVC measurement and control loops [93]

Feedback from a small number of real-time measurements at key locations is applied to the network model to estimate the range of voltages. Should the estimated voltage at any point on the network approach the statutory limits, GenAVC sends a control signal to the transformer Automatic Voltage Control (AVC) relay to adjust the voltage set point appropriately. The consequent tap change operation on the primary transformer then restores the network voltages within statutory limits.

2.5 GB grid conditions for wind farm connections

2.5.1 The Grid Code

The GB Grid Code [23] outlines the operating procedures and principles governing the relationship between national grid electricity transmission (NGET) and all Users of the National Electricity Transmission System, including Generators, DC Converter owners, Suppliers or Non-Embedded Customers. The Grid Code specifies the day-to-day procedures for planning and operation of the GB network at normal and abnormal circumstances. It includes connection conditions which specifies the minimum technical, design and operational criteria that must be complied with by Users connected to or seeking connection with the National Electricity Transmission System or by Generators (other than in respect of Small Power Stations) or DC Converter owners, connected to or seeking connection to a User's System. The Connection Conditions (CC) of the Grid Code specify both:

1. The minimum technical, design and operational criteria which must be complied by;
   (a) any user connected to or seeking connection with the National Electricity Transmission System
   (b) Generators (other than in respect of Small Power Stations) or DC Converter Station owners connected to or seeking connection to a User's System which is located in Great Britain or Offshore, and
2. the minimum technical, design and operational criteria with which NGET will comply in relation to the part of the National Electricity Transmission System at the Connection Site with Users

2.5.2 The Distribution Code

The GB Distribution Code [94] authored by the DNO's establishes recommendations for the security of electricity transmission and distribution systems of network operators. It outlines distribution license duties which covers materials and technical aspects relating to the connection and operational use of the DNOs distribution system and the compliance requirements of users at the point of connection. It also set out the scope for potential and existing generators, suppliers and customers connected to or seeking to connect to the DNO's distribution system. The Distribution Planning and Connection Code (DPC7) sets out the requirements for the connection of embedded generation (EG) on the distribution network. It specifies the minimum information required by the DNOs during connection applications to model the impact of embedded generation on the distribution system to decide appropriate connection methods and voltage levels.

2.5.3 Engineering Recommendations

Engineering recommendations G59/3 [95] produced by the operations directorate of the energy network association (ENA) provides guidance and route map on the connection of generating plants to the distribution system of licensed DNOs. The guide addresses all aspects of the connection process and ensures that all generators and customers are aware of the DNO's requirements before accepting generator connections onto the network. The guidance is designed to facilitate the connection of DGs and to maintain the integrity of the distribution network. The mandatory requirements that governs the connection of DGs are generally outlined in the Distribution Planning and Connection Code (DPC7) of the Distribution Code [94] and the Connection Conditions (CC) of the Grid Code [23].

Engineering recommendations G83/2 [96] is purposed to simplify and standardise the technical requirements for the connection of small scale embedded generators (SSEGs) operations in lower voltage distribution network. A SSEG in [50] is defined as:

A Generating Unit together with any associated interface equipment, if required (e.g. Inverter(s)) that can be used independently, rated up to and including 16A per phase, single or multi-phase 230/400V AC and designed to operate in parallel with a public low voltage Distribution System.

This corresponds to 3.68 kW on a single-phase supply and 11.04 kW on a three-phase supply. The guide addresses all the technical aspects of the connection process and specifies the connection requirements for SSEG integration onto the distribution network. The procedures outlined within the guide are designed to facilitate the connection of SSEGs whilst maintaining the integrity (in-terms of safety and quality) of the low voltage distribution network.

2.5.4 Voltage control and reactive power requirements

Engineering recommendation P28 [97] specifies the planning limits for voltage fluctuations on the GB network. The limits have been set out to allow the maximum utilisation of the distribution network system's capacity to accept fluctuating loads without an excessive risk of provoking customer complaints. A $\pm3\%$ general limit on the allowable magnitude of voltage changes, have been the accepted practise for many years. The statutory voltage limits on the GB network are also defined in the Electricity Safety, Quality and Continuity (ESQC) Regulations 2002 [98] and it specifies that, low voltage (LV) customers be supplied at 400/230V with tolerance of +10/-6% whereas high voltage (HV) customers, at tolerance of $\pm6\%$.

The connection of DGs to the distribution network are required to be designed in such a way that, operations of the generating plant does not adversely affect the voltage profile and the existing voltage control process already in place. Distributed generators who receive connection offers may be required to operate at certain conditions set out by the DNO that must be complied with. These are usually outlined within the connection contracts or agreements prior to making a connection. The operational conditions may include voltage control limits and reactive power requirements that must be adhered to at the DG point of connection. The ENA engineering technical recommendations (ETR) 126 provides DNOs with guidance on active management solutions to overcome voltage control limits [95]. Where it is agreed that the DG should operate in voltage control (PV) mode or where there is a need to comply with Grid Code CCA7.2 arrangement, the DG will have specific role to control the distribution system voltage.

The connection of wind farms to the grid requires continuous monitoring and control of voltage at the point of connection within the rated active and reactive power limits. There are three main control modes required to control reactive power generation of a wind farm and these are:

1. Voltage Control (VC) mode
2. Power Factor Control (PFC) mode
3. Reactive Power Dispatch (RPD) mode

Figure 2.17 provides a basic schematic of the reactive power control modes of a modern wind farm generator.

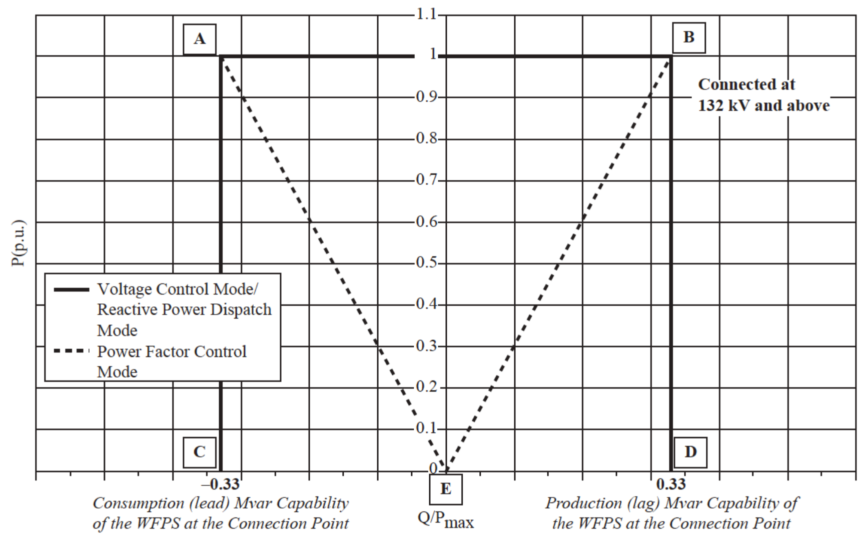


Figure 2.17: Reactive power control modes of wind farms [99]

From here it is seen that when the wind farm is operating at voltage control (VC) mode, the minimum reactive capability is defined by the area bounded in the square ABCD in the voltage control characteristics. Conversely, when the wind farm is operating in power factor control (PFC) mode, the reactive capability is defined by the area bounded in the triangle AEB in the power factor control mode characteristic. When the wind farm is operating in reactive power dispatch (RPD) control mode, the wind farm must be capable to export or import MVAr within the square area ABCD.

The technical requirements to control voltage differ between wind farms connected at different voltage levels. Nevertheless, section CC.6.3.4 of the UK Grid Code requires that, the reactive power capability must be fully available at all system voltages in the range ±5% of the nominal. The clause continues to offer a relaxation of the requirement applying to wind farms connected at 33 kV or below. The minimum reactive power capability requirement for onshore non-synchronous generators described in the Grid Code (CC.6.3.2) at the network interface is illustrated in Figure 2.18. Here, the MVAr capability can be reduced on a pro-rata basis depending on the number of wind farm connections in service.

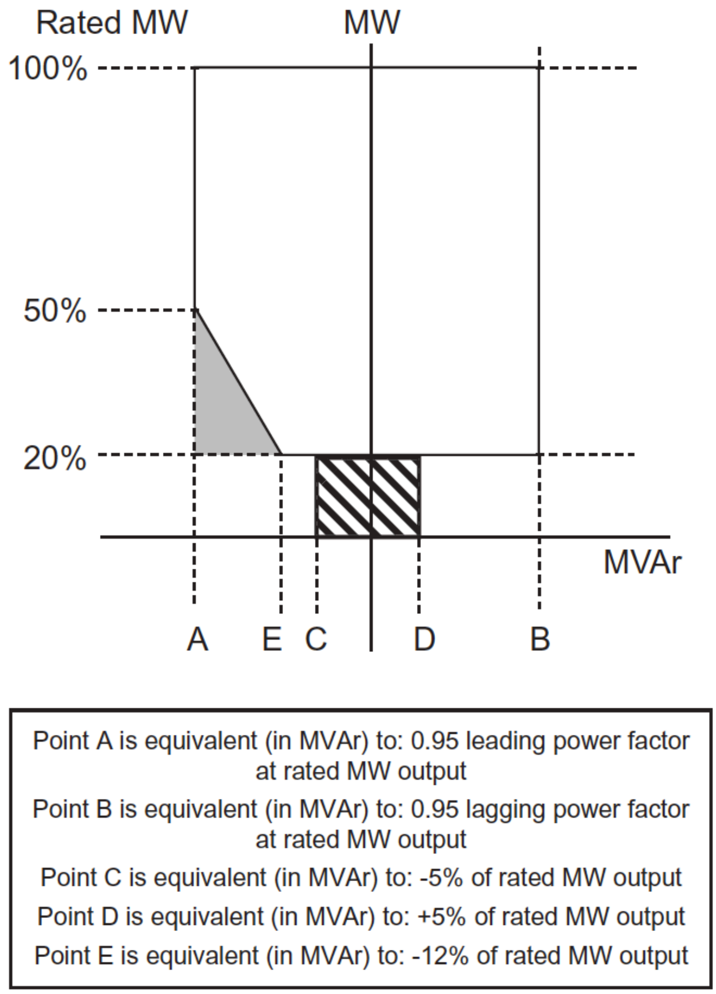


Figure 2.18: GB reactive power requirement [75]

At active power levels below 20% of the rated MW output, there's no requirement for reactive power capability to control the voltage. At active power levels above 20% of the rated MW output, the requirement defines the minimum capability. Section CC.6.3.8 of the Grid Code requires that; there should be a smooth transition between voltage control at active power levels greater than 20% of the rated MW output and reactive power control at active power levels less than 20% of the rated MW output. Under such circumstances, recent variable speed wind turbine technologies can take advantage of such contractual opportunities to provide optional reactive power service to the grid (beyond the basic mandatory reactive service) covering the period when there are limited wind resource.

Figure 2.19 specifies the minimum acceptable reactive capability when operating under steady state conditions within a voltage range of 95% to 105%. The voltage envelope shown here is measured at the DG Grid Entry Point or User System Entry Point at 33 kV and below.

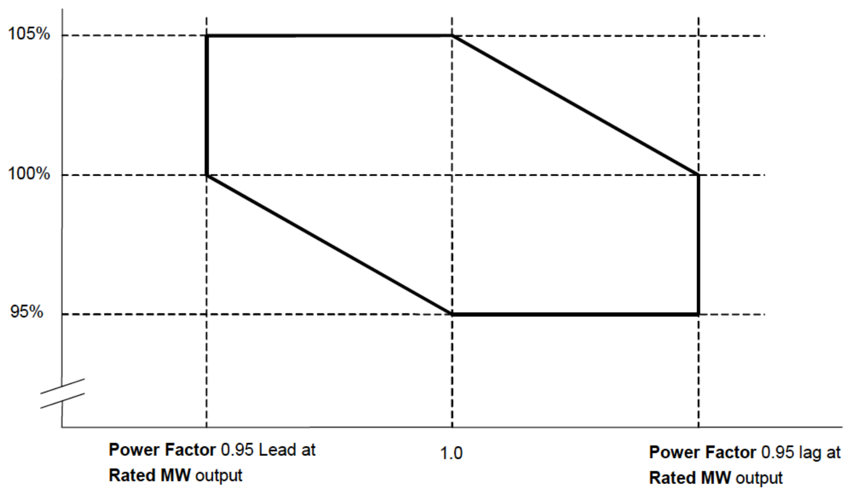


Figure 2.19: Reactive/Voltage range requirements for embedded generators connected at 33 kV or below [100]

2.6 The advent of active network management and smart distribution networks

Active network management (ANM) technologies in current distribution networks has emerged as a means to optimally utilise network capacity and to facilitate greater DG connections on constrained networks, deferring the need for costly reinforcement. The ANM philosophy is an instance of current and future smart grid networks. It involves a move away from the paradigm of passive fit and forget methods towards network planning to an active approach. It involves real-time autonomous control of the system to maintain the network security within operational limits. An ANM scheme offers the benefit to facilitate the connection of additional DG capacities beyond the firm limits by giving the network operators greater visibility and control of the grid and DG operations. This allows the operator to optimally utilise the existing network capacity to integrate energy storage, demand side management, renewable generation and other controllable resources on the grid leading towards a smarter and more efficient energy system.

Active network management means that DNOs have greater level of flexibility in network development, making it easier to implement incremental changes such as the connection of new generators. Active network management technologies are particularly relevant at rural networks where voltage and thermal constraint issues are prevailing factors that limits greater connection of DGs [101]. Voltage management is at the centre of active network management. Active network management techniques have potentials to significantly increase the utilisation of the existing network headroom capacity in an efficient and cost-effective manner [92]. They can be applied to increase network security and reliability of supply, connect distribution generation or reduce operational cost and provide financial benefits for both load and generator customers.

The advent of ANM technologies can also be deployed to provide DNOs with capabilities to assist the system operator on issues relating to system stability and balancing as well responding more effectively to customer requests for new connections. ANM solutions can be used with both generation and demand customers on the transmission and distribution networks. However, the most common use to date has involved DNOs offering ANM connections to generators wishing to connect to constrained parts of the network. ANM connections allows generators to connect more quickly and at lower cost by including provisions for curtailing their output during constrained periods to avoid the need for reinforcement [20].

2.6.1 Smart grid systems and active network management technology

Distribution network operators in the UK are actively planning to accelerate large volumes of distributed (and often intermittent and renewable resources) generation connections on their networks. As well as the traditional reinforcement approach to release additional network capacity, an alternative and innovative way to second generation network management is through smart grid technology. Smart grid technology equips the network to actively manage the bi-directional power flows created by DG power injections, deferring the need for capital intensive network upgrades.

This concept have become relevant for the growth of renewable generation development particularly, on-shore wind power. The techniques covered in an ANM solution include: voltage management, generation curtailment, dynamic line rating, energy storage, demand-side management and dynamic pricing. Actions required to implement the techniques involves coordinated operation of network equipment, widespread monitoring, communication systems. Advanced algorithms can also be embedded locally at the distribution substation or centrally to transform the network into an active system which can be dynamically controlled and automatically configured. Technical requirements for ANM solution can be defined in a range of areas including:

- Communication and interfaces which is critical for the implementation of ANM solutions. The choice of solution should consider latency, reliability, availability, security and ease of installation.
- Monitoring and data management should consider the ease of installation, access and maintenance of the monitoring equipment.
- The ANM system should be reliable, available, failsafe and autonomous.

- Operational interaction and compatibility with existing systems and processes including DGs, loads, SCADA/EMS/DMS, network measurement points, OLTC, storage systems, protection devices etc.

The concept of ANM solutions involves a range of software, automation and communications that monitors constraint locations (voltage, thermal or fault level limits) and issues control signals in real-time to actively manage available resources, ensuring that network parameters remain within the pre-defined limits. When those limits are breached, ANM takes action, for example, by curtailing or tripping the generator that is causing the breach. If more than one generator is affected, the order of curtailment is assigned following a pre-defined principles of access (PoA) to the network. Smart grid transformation includes the following approach:

2.6.1.1 Active management of distributed generation

The use of communications equipment and centralised control systems to limit generation for short periods, when output exceeds the operating limits of the network [102, 103]. This can be referred as curtailment and is a major focus of this thesis. The curtailment approach can be implemented to ease up power flow congestions and control voltage rise on the network. On the contrary, excessive curtailment can also hinder greater economic benefit to existing and future DG investments.

2.6.1.2 Demand side response

This is where electricity consumers adjust their usage to help manage a constraint on the network, for example a large industrial customer could adapt their shift pattern slightly to manage a peak time network constraint.

2.6.1.3 Energy storage

Here, electrical energy is converted to another form of energy and stored, before being changed back to electricity when required. Storage sites can import or export electricity where there is a temporary shortage or excess of generation in a region.

At present, there is a considerable momentum within the GB electricity industry towards the implementation of ANM solutions in network management. Most GB ANM schemes have been initiated as innovative funded projects. These have been coupled with a remarkable number of trial networks and demonstration projects to address some of the key technical and commercial issues as listed in [104]. ANM is now becoming Business as Usual (BaU) for a number of DNOs. The earliest ANM schemes on the GB network have been implemented as part of innovation projects. However, some DNOs are beginning to integrate such approaches into their Business as Usual practices. On the GB network, ANM solutions have been successfully deployed and demonstrated at various locations in notable projects such as the Scottish Hydro Electric Power Distributions Orkney ANM scheme [105], UK Power Networks Flexible Plug and Play project [106], and the Scottish Powers Accelerating Renewable Connections (ARC) project [107]. These deployments have been supported by innovation funding mechanisms such as the Registered Power Zone (RPZ) and Low Carbon Networks Fund (LCNF), established by the energy regulator Ofgem.

2.6.2 Challenges of current and future active network management

The benefits of ANM integration in distribution networks are evident; however there are also a number of barriers for implementing the technology. Active networks might speed up connections and help reduce investment costs of DGs, however may increase network operational costs (e.g. losses). ANM technologies heavily relies on communication devices, therefore the reliability, widespread and continuous interactions with these systems is crucial. The new systems need to be integrated within the existing infrastructure and a good coordination with the existing systems and network management routines could be challenging. Safe and explicable operation of the system needs to be maintained while accommodating ANM technologies into the distribution networks.

2.7 Summary

This chapter has reviewed recent fundamental changes in the UK's electricity industry which has provided a springboard for increased growth in distributed generation connections. It has reviewed existing literature on traditional voltage control methods at passive distribution networks in the absence of DG's. It provides an overview of current active voltage control methods and the role of active network management (ANM) technologies when the DGs are connected.

The integration of DGs invalidates the basic simplifying assumption of unidirectional power flows used in conventional voltage control methods for passive distribution networks. The review highlights the necessity to move from the previous fit and forget approach towards an active system which offers benefits of greater controllability, monitoring, flexibility and visibility. To maintain the network voltages and overcome the restrictions placed on DG capacities, network operators require pragmatic changes and a complete move towards active approach to network management, which may in the long-term defer the need for significant reinforcement.

Clearly, emerging active network control technologies are capable of providing an efficient and cost effective solution for issues associated with improving network performance to accommodate increased growth of DGs. However, addressing the voltage rise problem efficiently will require a well-coordinated distribution management system (DMS) that can control transformer tap changers, active generation, network loads and reactive power generation.

Integration of DG's to the network presents a host of challenges and as such, certain key aspects of the network needs to be carefully analysed before implementing the emerging ANM technologies. Factors such as existing network infrastructure, the impact of future growth of DGs, telecommunication systems, bandwidth requirements and costs associated with ANM schemes need to be taken into full consideration.

Chapter 3

DISTRIBUTION NETWORK VOLTAGE CONTROL THROUGH ACTIVE POWER CURTAILMENT

3.1 Introduction

Previous Chapters presented discusses an active approach to distribution network management as a key factor to maximising the economic benefit and technical viability of DG connections at weak distribution networks. This chapter investigates distribution networks voltage control using active network management (ANM) technological tools such as, active power curtailment of wind farm generators. The chapter studies the rules under which curtailment or limited network capacity is shared among multiple wind farms connections using principles of access (PoA) under network voltage constraint conditions. It assesses the current PoA arrangement deployed at ANM schemes in the UK for thermally constraint networks and it tests it's effectiveness when applied under voltage constraint conditions. A case-study network is finally presented to quantify the benefit and impact on the wind farms when the PoA are applied on a representative UK generic distribution network.

3.2 Definition of curtailment

Curtailment of generation has been a normal practice since the beginning of electrical power system operations and usually refers to the reduction in generation output from what it could otherwise produce [108]. Definition of curtailment varies in many forms. In the context of distribution system operations, curtailment refers to any limitation that prevents a DG exporting its maximum capacity to the distribution or transmission network [109]. In [60], the authors define curtailment as the reduction of generation output to an output level lower than available. In [110], curtailment is defined as an instance when a generation unit produces less than it could due to marginal cost characteristics. Curtailment practice in distribution networks is one among many network management techniques to facilitate cheaper and faster DG connections [101]. Curtailment has become useful in distribution management systems to maintain energy balance including grid capacity, demand response and storage.

In recent decentralised energy and power networks, owners of intermittent generators like wind, solar, wave and tidal are increasingly concerned about the impact of curtailment on their investment. Wind farm generation development projects usually require significant investments [111] and the economics of generation depends on the availability of sufficient wind resource and network capacity. Available and sufficient wind resource presents an opportunity to recover substantial initial capital cost and also to maximise profit.

However, frequent and excessive curtailment of the intermittent generators presents a major drawback for the developers than it is for fossil fuel generators as generation capacities are a capital intensive investment option. Wind farm development located at remote sections of the distribution network are likely to experience frequent and excessive curtailment due to the weak nature of adjacent networks and as such, can be a major hindrance to greater wind farm investment. Furthermore, for network locations where the expected curtailment levels in itself are quite low, can become problematic and tend to raise uncertainties from an investment security perspective due to constraints or insufficient network capacity.

Operator-induced curtailment typically occurs as a result of network constraint issues (thermal, voltage or fault levels), insufficient network capacity occurring through excess generation during minimum demand and network security issues. As discussed by the authors in [111], it is sometimes possible where the different types of curtailment are correlated in time. If there is a risk of curtailment due to overall excessive generation, there is probably also curtailment due to network constraint. In such events, the operator or utility provider instructs the generators to reduce their power output to levels that minimises or alleviates the constraint. This method of network management is usually a precautionary measure of the operator to ensure a safe, secure and reliable operation of their network and also to demonstrate compliance with regulations.

Generally, operational curtailment at short-time scales occurs as a result of network constraint issues. Generation curtailment are used as precautionary measure to maintain system stability in the event of extreme changes in network conditions such as; increased grid fault levels etc. Curtailment due to network security issues are usually related to controlling the limits of frequency, voltage and reactive power during steady state operations as well as post-fault conditions.

Depending on the network configuration and characteristics, wind power curtailment has been suggested in [112] as a way of solving grid constraint issues across varied time scales. In [110], some curtailment of fluctuating (variable) generation to an extent is argued as an optimal solution for minimising system integration cost. At short time intervals (minutes to hours), curtailment practices can alleviate network constraints, maintaining the system within the steady state voltages and reactive power limits and balancing excess generation relative to low demand levels [113]. At longer time-scales (hours to years), curtailment has been suggested as a solution for optimising grid capacity investment [114]. In [115], curtailment is discussed as the primary driver to facilitate cheaper and faster DG connections. In [110], the authors highlight generation curtailment (within hours) during a network constraint as an incentive for investors to find locations with least risk of curtailment. In [56], curtailment is used as an essential tool to determine available capacity of the grid for new non-firm generation connections.

3.2.1 Firm and non-firm connections

Distribution network operators are increasingly searching for economically viable commercial arrangements that accelerates DG connections in a timely and cost effective manner [116]. Based on firmness of connection, two types of contracts are usually available on the distribution network: *firm* and *non-firm* connections. A wind farm generator seeking to connect a significant amount of capacity may be offered a *firm* contract by the operator on condition that an investment is made (by the developer) in the necessary network reinforcements. *Firm* connection is the traditional connection agreement which allows the export of full generation capacity to the distribution network regardless of network configuration or security conditions (typically $N-1$). They are usually established based on a snapshot assessment of the worst-case situation of maximum generation and minimum demand. In [117], *firm* connections are considered more reasonable for non-variable energy resources such as CHPs due to their sustainable maximum power output for extended periods.

Under *non-firm* agreement, the developer may not be able to justify the expense of the required reinforcement and may negotiate a constrained connection agreement. Under this arrangement the DG scheme is tripped off or constrained under certain network operation conditions. Here, in the event of network constraints (being it voltage, thermal or fault level constraints which tend to be the most serious issues), the DNO reserves the right to reduce the generation output based on the terms and conditions set out in the interruptible contract agreement. The reduction in generation output through tripping or trimming of DG units is to ensure network security parameters remain within limits and also to demonstrate compliance with regulations. At certain circumstances of limited network capacity, this kind of connection agreement allows generators to connect larger nameplate capacities in exchange for a reduction in output at specific times. *Non-firm* connections occurs to be beneficial to variable energy resources such as wind, solar, wave and tidal due to their intermittent nature and fluctuating power output. DG curtailment are expected to occur more frequently due to network constraint increases.

The rules which dictates the order and frequency of curtailment is defined as Principles of Access (PoA).

3.3 Principles of access

The rules that define the customers rights to access network capacity and the terms under which the customers rights may be curtailed to alleviate network constraint is termed as principles of access (PoA) [20]. They define the relationships between all users (i.e. generators and demand) and available network capacity within an ANM system. Generators that connect to an ANM scheme will be aware of the risk of curtailment in advance. Flexible connection arrangement through non-firm contracts allows the generators to connect to the network when they may previously not have been able to, as a result of lengthy waiting periods and expensive connection cost.

A number of PoA have been proposed in the past as the rules by which generators could be curtailed at situations where they contribute to the constraint [59]. To develop a better understanding of the different PoA, they will be split into two main categories; *market* and *non-market* arrangements as shown in Figure 3.1. The two categories discussed, reflects the level of control the generators have over their own curtailment. In a *non-market arrangement* (which is the main focus of this thesis), the PoA is defined by the network operator and in a *market arrangement* the generator can indicate their willingness to be curtailed through a market process.

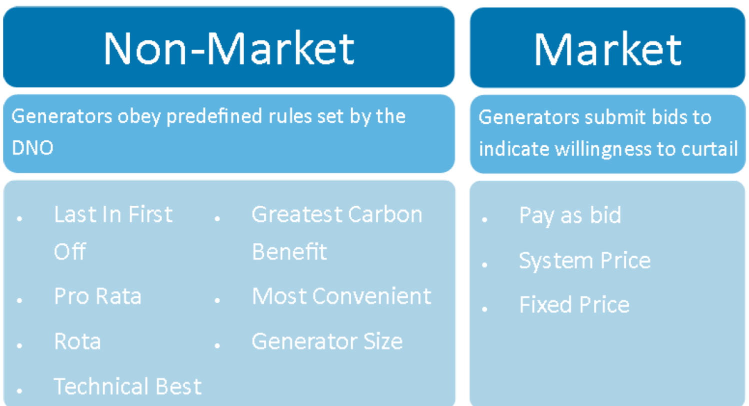


Figure 3.1: Market and non-market based PoA [60]

- Last-In-First-Out (LIFO): Here, marginal curtailment caused by new and additional generators is assigned onto those new generators alone. Binding constraint on the network is resolved by curtailing generators in the order at which they applied for connection on the network. In this way, existing non-firm generators are insulated against greater curtailment caused by the connection of new additional generators and is demonstrated in Figure 3.2.

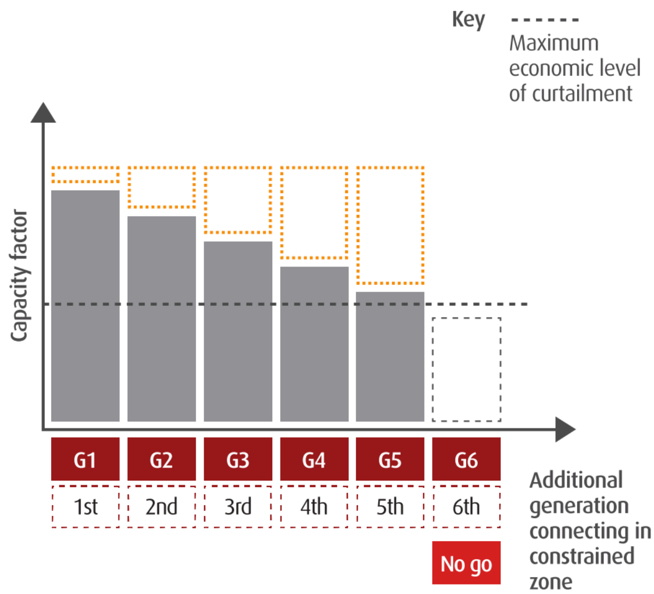


Figure 3.2: LIFO principles of access arrangement [20]

- Pro-rata : In this arrangement curtailment is shared equally among all generators in proportion of their nameplate capacity and contributions to the constraint and is demonstrated in Figure 3.3

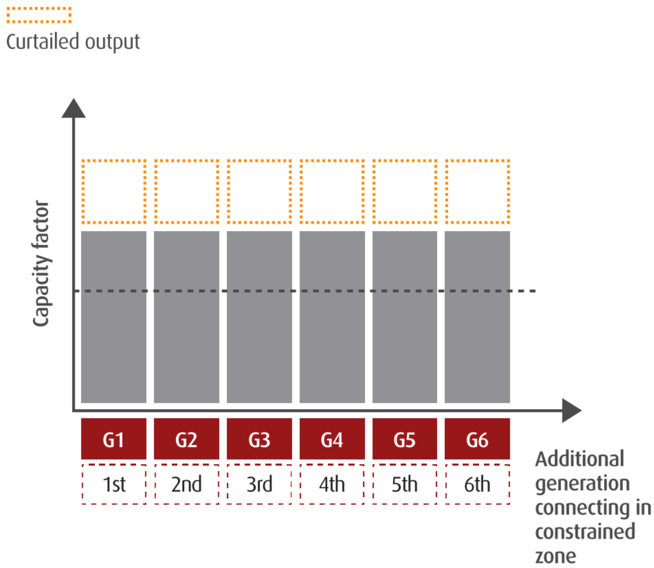


Figure 3.3: Pro-rata principles of access arrangement [20]

- Rota : This method curtails the non-firm generators in an order specified in a predetermined rota schedule. The frequency of a rota arrangement are scheduled on daily, weekly or monthly basis and usually at the network operator's discretion.

- Greatest carbon benefit (Lowest carbon last): Here, generators are curtailed in order of carbon intensity where DG units with the lowest emission levels are curtailed last.

- Technically best/most convenient/Generator size generators are curtailed on the basis of operational efficiency and/or reduced ANM sophistication.

- Market based : In this arrangement, generators bid their short run marginal cost and then are curtailed in the order of the least expensive first to minimise the aggregate cost of curtailment to resolve any given constraint.

  This thesis however, only focuses on the non-market based principles of access arrangement.

3.3.1 Assessment criteria

In developing appropriate commercial arrangement for generators connected under non-firm contracts, it is important to compare the merit of the different PoA options against a clear set of assessment criteria. Examples of the criteria used in recent assessment of curtailment allocation in an ANM scheme on the GB distribution network can be found in [59, 115].

3.3.1.1 Compliance with UK Grid Code

The Grid Code designed for the GB network is to promote development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity and to facilitate competition in the generation and supply of electricity [23]. The Grid Code is designed and covers all technical and operational aspects of connection to and use of the transmission or distribution system and as such, all PoA rules for sharing curtailment must fully comply with the codes.

3.3.1.2 Network utilisation

Principles of access rules should aim to maximise the utilisation of existing network capacity as well as generation capacities that can be economically connected in any constrained location.

3.3.1.3 Certainty

Certainty is of paramount importance to DG developers and stakeholders as to the financial impact of curtailment on their investment. The rules for curtailment applied to manage the generators should provide each generator with certainty as to the long term level of curtailment to be experienced. This can be achieved by providing generators likely levels of curtailment over time through accurate forecasting and guaranteeing maximum curtailment levels (capping).

3.3.1.4 Be clear and transparent

All rules for curtailment should be clear and transparent for all users of the system and not overly complex.

3.3.1.5 Simplicity

It is important that the commercial packages offered to developers of generation projects looking to connect must be simple, easy to implement and understand.

3.3.1.6 Support a safe, secure and reliable power system

The PoA solutions should allow the network operator to alter generation levels as and when required. However, when such changes are made the PoA is to ensure a safe, secure and reliable operation of the power network .

3.3.1.7 Fairness

The principles of access rules must be equitable in its allocation of limited amount of network capacity between generators with firm connections and new non-firm connections (NNFC).

3.3.1.8 Gain support of all stakeholders

Changes to the curtailment rules will affect DG owners and stakeholders in different ways. Any suggested changes in PoA will have to gain support of all stakeholders and parties involved.

3.3.1.9 Learning

The PoA solutions should maximise the useful learning and insight generated for the distribution network industry as a whole in relation to the commercial allocation of curtailment risk under smart technological solutions.

3.3.1.10 Robustness

The PoA arrangement must be robust in order to prevent exploitation of the network in particular, larger generators who could exploit the network and take advantage over smaller, community owned generation schemes.

3.4 Implementing voltage control through curtailment using a case-study network

This section presents a case-study using historical wind generation and network demand for a representative generic distribution network in the UK. The aim of this section is to model voltage control through generation curtailment. The case-study utilises optimisation techniques to give a set of results for analysis. It highlights the complexities of voltage rise constraint issues which is presently, a major barrier to greater wind farm connections in the UK. The case-study presented, investigates the rules for sharing curtailment among multiple non-firm wind farms when managed under network voltage constraint conditions.

3.4.1 Case study questions

The optimisation method in this section is used to analyse the case study and specifically to answer the following key questions.

1. How can we investigate the rules of curtailment of multiple wind generation connections to alleviate voltage rise constraint issue in active distribution networks?

2. Are there suitable PoA arrangement that can maximise the economic viability of the wind generators to achieve a minimum capacity factor of 25% when curtailment is applied?

3.4.2 Network model description

The operation of voltage control through wind generation curtailment is demonstrated on a realistic UK generic distribution test network (UKGDS) [HV UG-OHb]. Figure

3.4 presents the single-line diagram (SLD) of a 289-node radial distribution network developed in IPSA with full network data and parameters provided in [118]. The secondary busbars or nodes are represented by white circles containing node identification numbers. The nodes are connected by branches and the network configuration is a radial topology with three main 11 kV feeders (Feeder 1 , Feeder 2 and Feeder 3) connected to the primary substation. The case study is a large network with a total length approximately 70 km serving a mix of industrial, urban and rural customers, with demography of a medium population density. Feeder 1 is 10.5 km in length and consists of 40 secondary busbars, Feeder 2 is 24.2 km in length and consists of 102 secondary busbars and Feeder 3 is 34.4 km in length consisting of 147 secondary busbars.

The test network comprises of underground cables followed by overhead lines with varied X/R ratios and medium conductor lengths. The 11 kV network comprises a mixture of strong, medium and weak sections prone to voltage fluctuations. The primary substation supplies three 11 kV feeders and is linked to a 33 kV distribution system represented as a source of real and reactive power balance to the system. The primary substation is equipped with two identical 33/11 kV OLTC transformers each rated at 22 MVA, connected in parallel to regulate the network voltage to a pre-defined target.

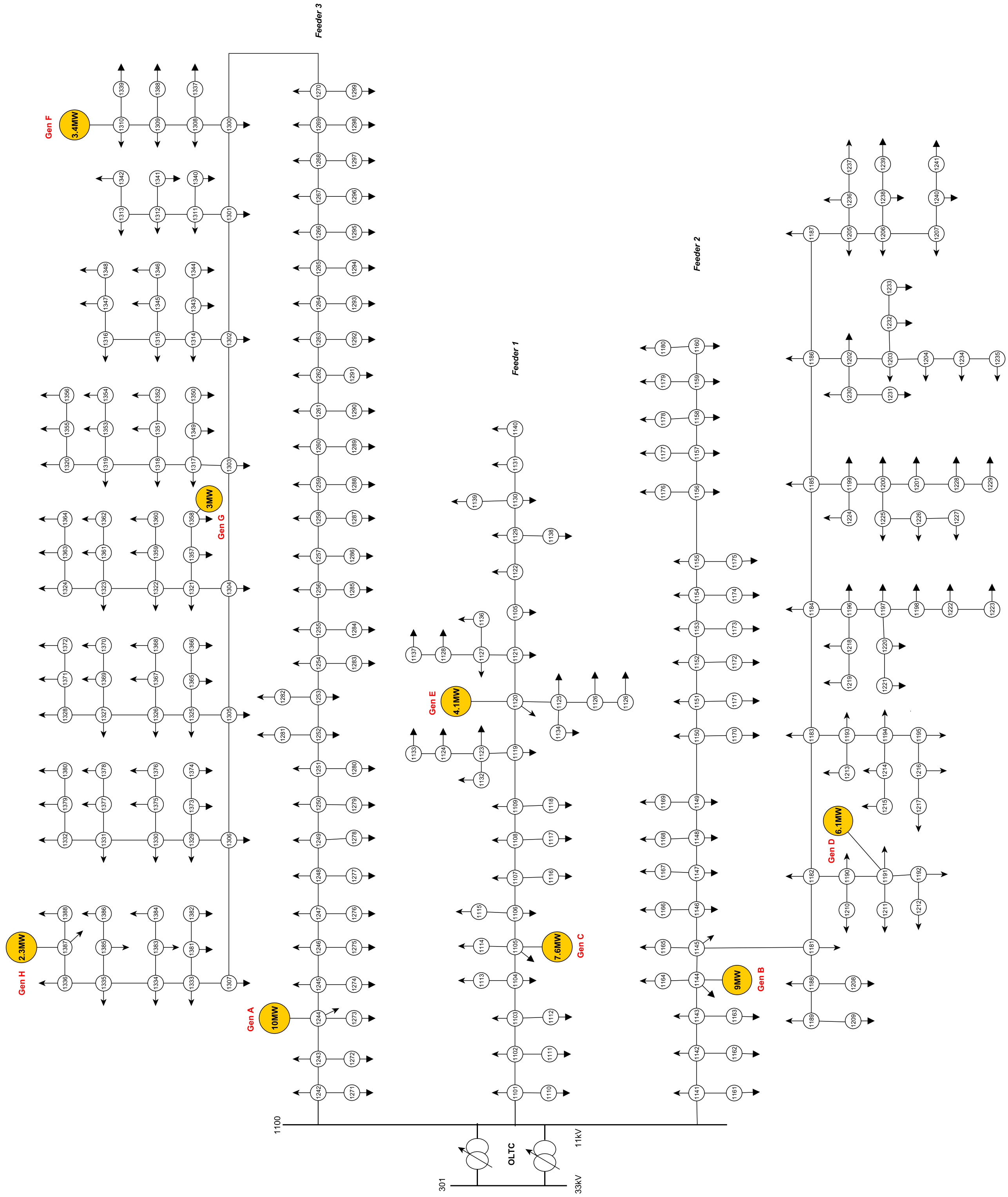


Figure 3.4: 11 kV radial distribution network

3.4.2.1 Network operation characteristics

The operation condition in this case-study sets and fixes the slack bus voltage at 10.89 kV (0.99 p.u). The secondary bus voltages are constrained at current DNO operational limits and allowed to vary within a permissible range of ±3% of the nominal. The medium circuit conductor lengths with varied MVA ratings are considered as additional thermal constraint on the network.

3.4.3 Load profile

Half hourly time-series demand profiles are connected on all secondary buses and consists a mixture of residential, industrial and commercial loads. These are aggregated values scaled from the load profile provided in [118]. The demand profile connected on the secondary buses displays regular daily and weekly variations. High demand periods occur during winter and early evening, lowest demand occurs during summer nights. The demand data is used as an input variable in the optimisation set up and Figure 3.5 present a 1-month snapshot of half-hourly demand data on the network.

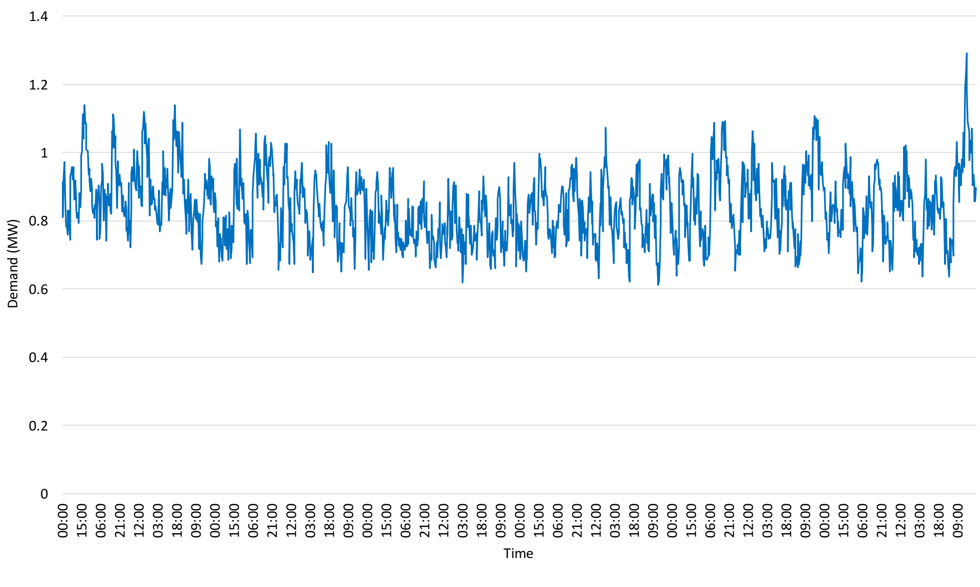


Figure 3.5: 1-month demand profile

3.4.4 Wind generation profile

The use of historic wind resource time-series, such as normalised output of a nearby wind farm is used to estimate curtailment and potential generation levels. A normalised wind generation profile of a wind farm represent the power output varying between a maximum of 1 MW and a minimum of 0 MW displaying intermittency in wind power production. Figure 3.6 shows a time series production over one-month period of normalised wind generation output at half-hourly time intervals with a maximum capacity factor (CF) of 30%. The wind generation profile exhibits significant inter-seasonal variation in power outputs and encapsulates the inherent intermittent nature of typical wind farm power production in the UK.

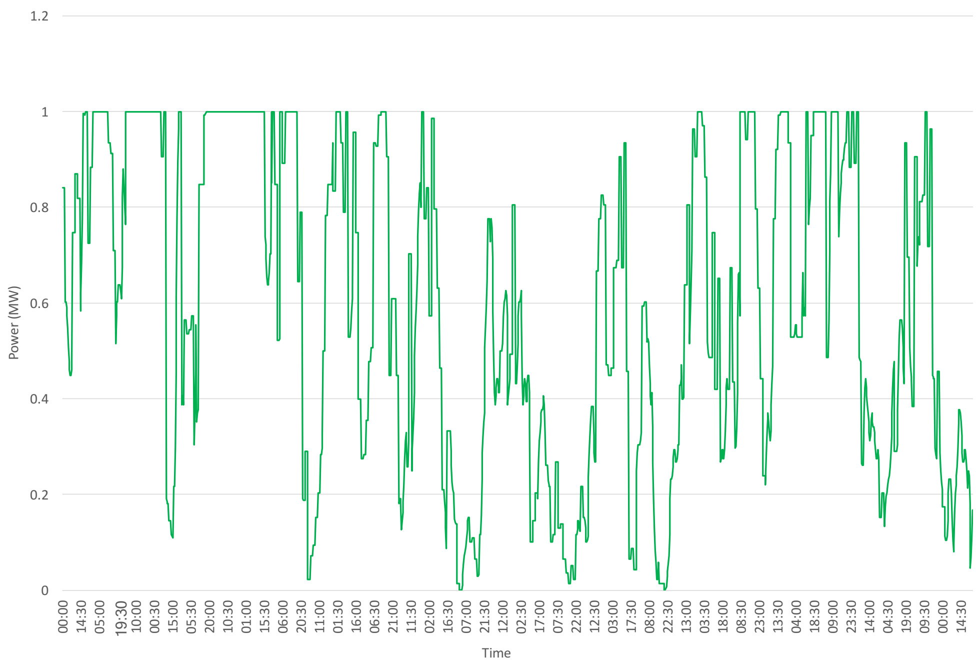


Figure 3.6: Normalised wind profile

3.4.4.1 Wind capacity assessment methodology

Previous work reported by the authors in [119] for DG sizing and placement applies AC optimal power flow (ACOPF) problem formulation through mixed integer programming (MIP) techniques.

Here, the object function is set to minimise the total cost of generation considering system constraints such as thermal limits, voltage, transient stability, active and reactive generation limits. In [120], a multi-objective evolutionary algorithm technique is studied for optimal sizing and siting of DGs resources in distribution networks. The problem is formulated as a multi-objective optimisation problem (investment cost vs cost of expected energy not supplied) and applies genetic algorithms (GA) solutions in search for a feasible system configuration. The methodology adopted permits the planner to decide the best compromise between cost of network upgrading, cost of power losses, cost of energy not supplied, and cost of energy required by the served customers. A Newton Raphson power flow method has been applied in [121] to assess DG hosting capacity on a UK generic distribution network. A multi-period ACOPF based technique for evaluating maximum DG capacity in ANM schemes have also been proposed by [78].

In this case-study network, the planning tool for assessing wind farm connection capacity on the 11 kV test network is determined using AC power flow techniques with voltage limit set as binding constraints. The amount of non-firm generation capacity that can be connected at any given node is established through deterministic load flow studies at maximum generation maximum demand conditions. The size of the generator at any given location is the maximum generation at which the voltage at the point of DG connection reaches the upper maximum limit with the assumption that all other generators are disconnected on the network.

The test network model is deployed in Matpower [122] where power flow simulation studies are performed. Here, the wind generators are modelled and connected to the network as PQ nodes and assumed to operate at unity power factor with no voltage control capabilities. Simulations are performed using sequential Newton-Raphson power flow algorithms at single time-step intervals with small kilowatts increments in generation at each time-step until the voltage at the point of connection reaches the upper maximum limit. A suit of eight non-firm distributed wind generator (DWG) schemes with nameplate capacities ranging from 2.3 MW - 10 MW are established and connected to the network at nodes 1244, 1144, 1105, 1191, 1120, 1310, 1358, 1387 and assumed to operate an ANM scheme as shown in the single line diagram (SLD) in Figure 3.4. All the wind generators are assumed to be exposed to the same wind resource and as such there is a correlation between the potential power output of all the wind farms. In this case, the time-series production for each wind farm is scaled from the normalised generation profile and the availability of the wind generation becomes an input to the optimisation model. A summary of the DG capacities are provided in Table 3.1

Table 3.1: Summary of non-firm generators

Generator	Capacity (MW)	Bus No	Technology
Gen A	10.0	1244	Wind
Gen B	9.0	1144	Wind
Gen C	7.6	1105	Wind
Gen D	6.1	1191	Wind
Gen E	4.1	1120	Wind
Gen F	3.4	1310	Wind
Gen G	3.0	1358	Wind
Gen H	2.3	1387	Wind

3.4.5 Optimisation formulation

In this case-study network, active curtailment of the wind generators has been adopted as an ANM tool to control the distribution network voltages. The active curtailment approach assesses available online capacity on the network and allocates curtailment behind the generators contributing to the constraint. Active curtailment operation of the wind generators is formulated as an optimisation problem that utilises time-series ACOPF [123,124] algorithms. The technique is used to assess the impact of curtailment on the wind farms when managed under voltage constraint conditions.

Optimal power flow (OPF) methods have been developed as a non-linear mathematical programming tool [125]. It has been widely used in many power system applications for a range of objectives including; minimisation of fuel costs, system losses and emissions, VAr planning, maximisation of generation and social welfare benefit [126]. In transmission networks, optimal power flow (OPF) methods have traditionally been used to dispatch a pre-defined set of generators to minimise generation costs and system losses. It has similarly been applied at distribution networks to address specific problems in network planning and operations. The scope of an OPF application in power system analysis is to minimise or maximise an objective function, whist taking into full account network operational constraints such as real and reactive power flows, generator limits, voltage limits, and branch flow limits [127, 128].

A novel application of time-series ACOPF techniques to manage DG power flows and curtailment under voltage constraint conditions still remains an open question and one that has not been fully investigated or tried in recent ANM schemes. The optimisation method adopted for this case-study utilises the standard ACOPF formulation at each time-step and models voltage control in the presence of multiple wind farm connections. The optimisation technique employs nonlinear programming (NLP) methods through Lagrangian techniques for the constrained optimisation problem [129]. The process involves the application of Kuhn-Tucker (KT) and Karush-Kuhn Tucker (KKT) first and second order necessary and sufficient conditions. The study aims to achieve the following combined system objectives:

1. control network voltages through curtailment
2. minimise the impact of DGs on the voltage profile
3. minimise wind generation curtailment

The ACOPF based problem is modelled similarly to the methods adopted in [130] as a set of nonlinear equations consisting equality and inequality constraints and are outlined as follows:

$$Optimise : f(x, u) \tag{3.1}$$

subject to

$$g(x, u) = 0 \tag{3.2}$$

$$h(x,u) \leq 0 \tag{3.3}$$

where; f represents the objective function, g represents the physics of the power system enforced through the power flow equations, h represents the parameter limits of the system. x represents a vector of state variables and it includes load bus voltages V_i, voltage angles θ_i, and can be expressed as:

$$x = \begin{bmatrix} V_i & \theta_i \end{bmatrix} \tag{3.4}$$

u represents the vector of control variables and includes generator real power P_{Gi}, generator reactive power Q_{Gi} and can be expressed as;

$$u = \begin{bmatrix} P_{Gi} & Q_{Gi} \end{bmatrix} \tag{3.5}$$

To control the network voltage rise conditions occurring at DG point of connection, the objective function can be formulated as;

$$min \sum_{i=1}^{N_G} |V_{Gi}^{rise}| \tag{3.6}$$

where:

V_{Gi}^{rise} refers to the prospective voltage rise condition at the i^{th} DG connected bus above the permissible maximum voltage. The quadratic cost function of the generators is represented as:

$$min \sum_{i=1}^{N_G} a_i + b_i(P_{Gi}^{curt}) + c_i(P_{Gi}^{curt})^2 \tag{3.7}$$

where a_i,b_i,c_i represents the cost coefficient of active power output P_{Gi}. The OPF model assigns high cost values to the swing bus to discourage grid active power imports from the grid supply point (GSP) and low cost values to all the DGs to encourage active demands on the network be met by the DGs. This configuration enables us to achieve our objective of maximising the DG power output. With an assumption of no prior knowledge of generator cost values and to allow non-bias due to the difference in generation costs associated with the different generator sizes, the OPF model assigns equal quadratic cost values to all the wind generators. This then allows the OPF to control and curtail the generators based on their impact on the constraint. The nodal power balance in equation (3.2) can be expanded as;

$$P_{Gi} - P_{Di} - \sum_{i=1}^{N_G} |V_i V_j Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) = 0 \tag{3.8}$$

$$Q_{Gi} - Q_{Di} + \sum_{i=1}^{N_G} |V_i V_j Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) = 0 \tag{3.9}$$

where; P_{Di} and Q_{Di} are the systems real and reactive demands at the i^{th} bus, while V_i, V_j , δ_i, δ_j are the bus voltage magnitudes and angles at bus i and j. Y_{ij} represents the admittance matrix.

The parameter constraint limits in equation 3.3 is expanded as:

- *Generator constraints :* Generator voltages, real and reactive power outputs are constrained by their upper and lower limits as follows:

$$V_{Gi}^{min} \leq V_{Gi} \leq V_{Gi}^{max} \tag{3.10}$$

$$P_{Gi}^{min} \leq P_{Gi} \leq P_{Gi}^{max} \tag{3.11}$$

$$Q_{Gi}^{min} \leq Q_{Gi} \leq Q_{Gi}^{max} \tag{3.12}$$

- *Transformer constraints :* The OLTC transformer tap settings are bounded as follows:

$$T_i^{min} \leq T_i \leq T_i^{max} \tag{3.13}$$

- *Security constraints :* These include the constraints of voltages at load buses

$$V_i^{min} \leq V_i \leq V_i^{max} \tag{3.14}$$

and thermal power flow limits

$$|S_{ij}| \leq S_{ij}^{max} \tag{3.15}$$

In this study, the thermal limits on the lines are deliberately relaxed to allow the voltage operate as binding constraints to control the generators.

3.4.6 Principles of access methodology

The sharing of curtailment or limited network capacity among non-firm generators on a constrained distribution network is implemented by principles of access. In this case-study, the principle of access are investigated and applied with objectives to identify suitable commercial arrangements that minimises wind generation curtailment when the network is managed under voltage constraint conditions. To compare the various merits and drawbacks, five different PoA rules are modelled to assess their impact on the wind farm generators when managed under network voltage constraint conditions.

Each PoA rule investigated quantifies the level of curtailment that may be experienced by the non-firm wind farms to maintain the voltage limits. It also estimates subsequent renewable energy yields that may be realised by the wind generators. With objectives to control system voltages and minimise wind farm curtailment, the following PoA rules summarised in Table 3.2 are modelled and discussed. Each PoA rule outlines the criteria for allocating the priority order at which the generators connect to the constrained network or are curtailed (in reverse order in such cases). It should be noted however that, the criteria for implementing majority of the PoA on this case-study network are assumed as real distribution network operators may have their own predefined set of rules. For example; LIFO for instance in the UK is implemented via the date of DG connections on real distribution network applications.

Table 3.2: Summary of principles of access (PoA)

PoA	**Priority order criteria**
LIFO	1. Connect electrically closest DGs first 2. Generator size (connect largest generator first) 3. Connect DGs at stronger network location first
Reverse LIFO	1. Connect electrically furthest DGs first 2. Generator size (connect smallest generator first) 3. Connect DGs at weak network location first
Most Convenient	1. Shortest distance feeder first 2. Connect electrically closest DGs first 3. Generator size (connect largest generator first) 4. Connect DGs at stronger network location first
Pro-Rata	1. Equal priority order for all DGs 2. Curtailment shared equally among DGs
Technical Best	1. Equal priority order for all DGs 2. Curtailment shared according to DGs impact on the constraint

Previous work reported by the authors in [61] involves an OPF priority order formulation in which the cost curves of each DG unit is modified and tuned to reflect the connection order, with the highest cost of generation associated to the last DG unit to connect. A similar pseudo cost approach to define the preferential curtailment of different generation technologies have also been reported by [117] where arbitrary cost values are assigned to the DGs to prioritise their dispatch. In this section a new OPF priority order methodology is modelled and implemented. The proposed methodology is part of the major contributions of this thesis. The methodology utilises ACOPF techniques to schedule DG connections one at a time using a multi-stage process.

The methodology sets and fixes the outputs of the highest priority generator with all lower-priority generators removed, then fixes that generator output for all further stages. Figure 3.7 illustrates a flow chart of the new priority order methodology implemented in the study and has been applied to LIFO, Reverse LIFO, and Most Convenient PoA. The multi-stage optimisation assesses available online network capacities and determines maximum generation levels that can be injected onto the constrained network.

This technique does not depend on fine tuning generator prices and can hence be implemented without prior knowledge of generator real market price values. In this study, all DG units are assumed to be operating at the same cost values.

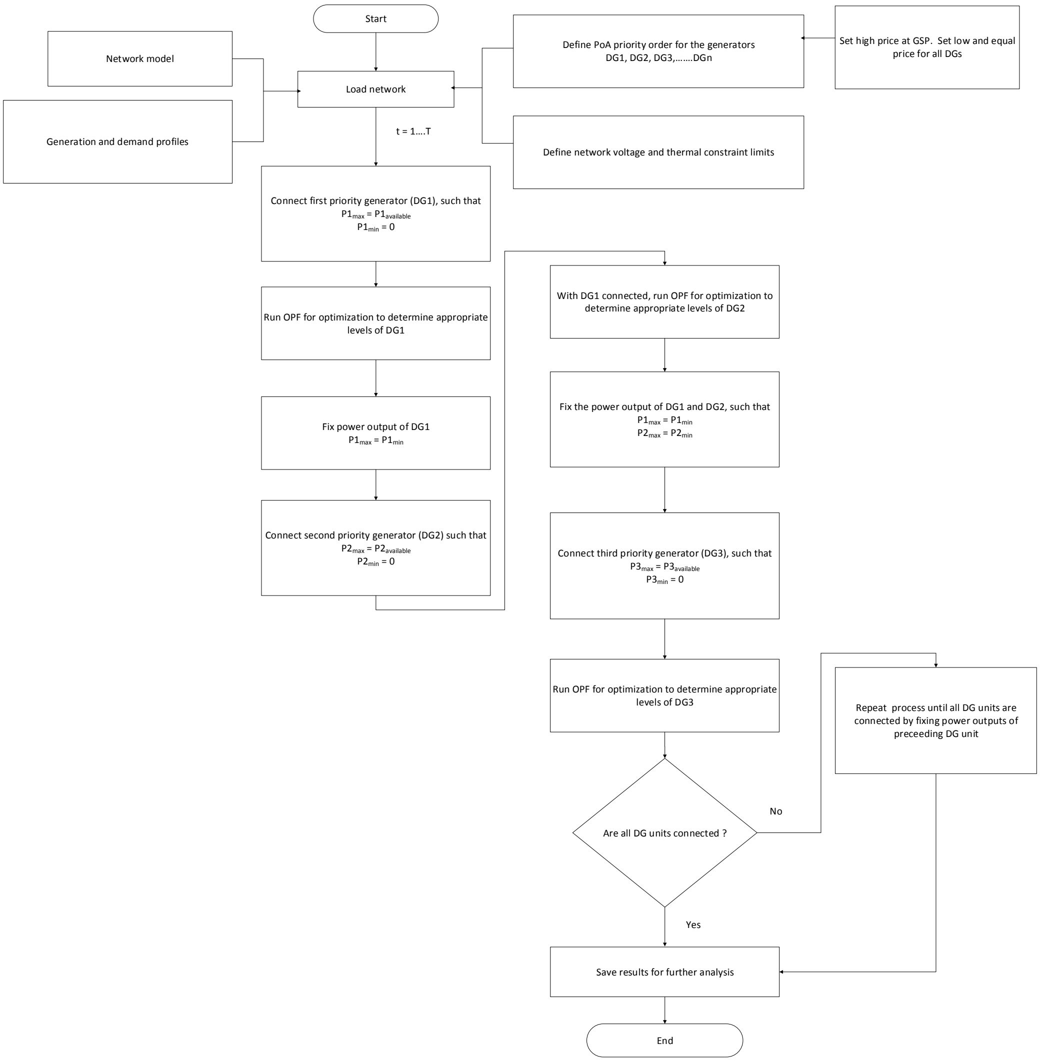


Figure 3.7: Process flow for DG connections

The model is deployed in Matpower [122] which uses interior point method (IPM) for the constrained nonlinear programming (CNLP) problem. Time-series simulations are performed over a month period at half-hourly resolution, consisting a total of 1440 time-steps.

3.4.7 Case - study results and discussion

This section presents and discusses results of the non-firm wind farm generators controlled by active power curtailment to maintain the system voltages. It demonstrates network voltage control and the sharing of curtailment risk among the multiple generators by applying principles of access. The case-study results presents the impact and benefit to the wind farms (in terms of generation capacities and economic viability) when the principles of access are implemented. The results presented are based on the principles of access options outlined in Table 3.2 and the table of results are summarised in Appendix B. The case study makes the following economic viability assumptions:

1. The non-firm capacity of each generator is defined as economically viable if it has a marginal capacity factor of 25% or greater.

2. If no curtailment is applied, the total capacity factor (C.F) of each generator corresponds to 30%.

3. A PoA is defined as economically viable if the sum of the CF's of the non-firm generators are greater than 25%.

The sharing of curtailment among non-firm wind generators to maintain network voltages within limits have been implemented by principles of access. Recent active distribution network operations have been characterised by competing system objectives including; minimising wind generation curtailment and maintaining network security constraints within limits. This is often a challenge to distribution network operators in terms of balancing the competing system objectives without compromising one or the other. The key question to answer here is, *which commercial arrangement is considered optimal by providing greater benefit to the wind farms when the network is managed under voltage constraint conditions?* Where optimal in this context refers to maximising the economic viability of the wind generators (minimising curtailment) whilst maintaining the network constraints within limit.

Recent ANM schemes in the UK such as the Orkney ANM project (led by Scottish and Southern Energy), Flexible Plug and Play (led by UK Power Network) have implemented LIFO and Pro-Rata principles of access arrangements to connect non-firm DGs on thermally constrained distribution networks. Both LIFO and Pro-Rata are currently, the most common PoA arrangement widely used in ANM schemes in the UK to manage grid congestion issues. They are considered simple and straight forward to implement when sharing curtailment among multiple non-firm DGs.

Whilst both LIFO and Pro-Rata have proven acceptable and successful for thermally constrained networks, the same is not true for networks where voltage constraint is binding. With a thermal constraint, the location of a generator behind a constraint does not change its impact on that constraint however, the same is not true for a voltage constraint where the location of the generator is a significant factor. Therefore, generators located at a weak section of the network will impact on the voltage profile significantly more than at a strong location and as such, may suffer severe amount of unnecessary curtailment. Also, in the event of thermal constraints all DGs are approximately equal contributors to the constraint however, this condition is untrue for voltage constraint situation as voltage rise is a local area problem at the vicinity of the DG.

To compare the various merits and limitations of the PoA investigated, Figure 3.8 presents a graphical summary of the total wind energy generated and corresponding CFs achieved under each PoA arrangement. Here it is seen that, adopting a Pro-Rata arrangement results in the least amount of wind energy yields when compared with the rest of the PoA investigated. The overall non-firm energy generation was recorded at 1942 MWh out of 12850 MWh available energy which corresponds to 15% total energy generation. The total energy curtailed was recorded at 85% and capacity factor achieved under Pro-Rata arrangement was recorded at 4.5% which is well below the minimum economic viability limit of 25%. Under this arrangement, the total curtailment required to alleviate the constraint on the network is calculated and shared equally among the DGs in proportion of their nameplate capacity and contributions to the constraint.

Pro-Rata arrangement does not fully take account of the impact of the DGs on the voltage profile at different network locations (as voltage rise issues is a local area problem). However, it sees all generators as equal contributors to the constraint. This as a result causes DGs located at the strong sections of the network with minimum impact on the constraint to be heavily curtailed which could otherwise contribute to maximising the overall generation levels. In other words, economically viable wind generators are treated equally as DGs with smaller nameplate capacities with significant impact on the voltage rise constraint. Based on the results obtained under this case-study network (or perhaps similar and future network arrangement where voltage constraint is binding), Pro-Rata is seen as not suitable for optimally sharing curtailment among non-firm DGs as it underutilises network headroom capacities. Furthermore, it does not fully maximise capacities of economically viable wind generators as it treats all the generators equally regardless of their network location when sharing curtailment risk.

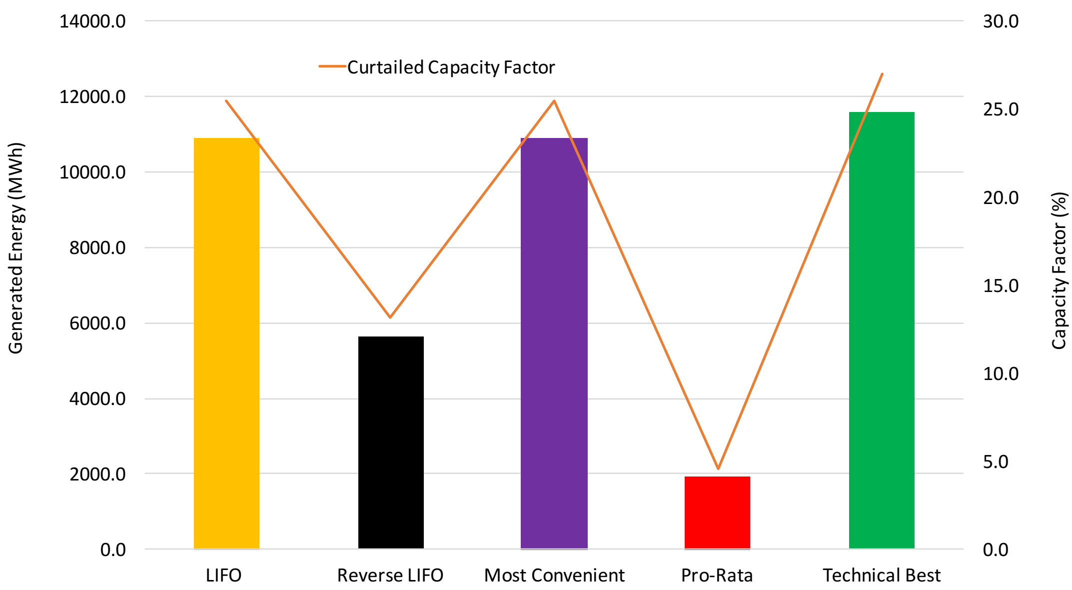


Figure 3.8: Total wind energy generated

Reverse LIFO arrangement yielded a total generation of 5633 MWh out of 12850 MWh available energy corresponding to 44% overall energy generation levels. The total energy curtailed was recorded at 56% and the total capacity factor achieved under

Reverse LIFO arrangement was recorded at 13% which is below the minimum economic viability limit of 25%. The criteria under which Reverse LIFO is implemented in this case-study network provides greater access to DG units connected at the weak sections of the network. Under this arrangement, smaller sized DG units remotely connected at the weak sections of the network with significant impact on the voltage profile are granted high priority access to the network than larger sized generators connected at the strong sections of the network. In this case-study network it is seen that, adopting a Reverse LIFO arrangement underutilises the network headroom capacity resulting in reduced energy yields minimising the economic benefits for the DGs.

Under LIFO arrangement, a total energy generation of 10898 MWh was realised out of 12850 MWh available energy corresponding to 85% overall energy generation. The total energy curtailed was recorded at 15% and capacity factor achieved under LIFO arrangement was recorded at 25.4% which is marginally above the economic viability limit. Unlike real distribution networks where LIFO arrangement is implemented by the date of DG connections. This case-study network assumes an onerous scenario where the date of connection is implemented via electrical distance, size of generators and strength of network at the vicinity of the DGs. In this case-study network where voltage constraint is binding, LIFO is seen as a potential commercial arrangement to optimally allocate curtailment among the non-firm DGs.

Under Most Convenient arrangement, similar results to LIFO are obtained such that, a total energy generation of 10898 MWh was realised out of 12850 MWh available energy corresponding to 85% overall energy generation. The total energy curtailed was recorded at 15% and capacity factor achieved under Most Convenient arrangement was recorded at 25.4% which is marginally above the economic viability limit. In real UK distribution networks, a Most Convenient PoA under thermal constraint conditions is implemented by the network operator to curtail generators they know to be the most convenient to respond to the network constraint. However, in this case-study network where the objective function is to control voltages and minimise generation curtailment, the criteria for implementing Most Convenient PoA was based on feeder lengths as a convenient method to optimally share network capacity that minimises

DG curtailments. In this case-study network where voltage constraint is binding, Most Convenient PoA is seen as a potential commercial arrangement to optimally allocate curtailment among the non-firm DGs.

Under Technical Best arrangement, a total energy generation of 11572 MWh was realised out of 12850 MWh available energy corresponding to 90% overall energy generation. The total energy curtailed was recorded at 10% and capacity factor achieved under Technical Best arrangement was recorded at 27% which is above the minimum economic viability limit of 25%. Here, all DGs have equal priority access to the network and generation capacities are neither influenced by the system operator nor the generators. In this arrangement, the optimisation engine optimally shares the curtailment in order of generator's contributions to the voltage constraint, taking full account of the impact of the DG locations on the voltage profile. Based on the results obtained in this case-study, Technical Best PoA arrangement provides the most economic benefit to majority of the wind farm generators with the exception of generator H where Reverse LIFO is most favourable. However, with an overall objective to maximise wind farm generation capacities selecting a suitable PoA that fulfils this objective outweighs the benefit of selecting a PoA that is only favourable to a small number of generators.

The wind generator units performs differently in terms of energy generation levels when the various PoA techniques are applied to connect the DGs. To assess the suitability of the PoA for the DGs, each generator is assessed under the different PoA to investigate the impact on generation capacities. Figure 3.9 illustrates the performance of the DGs and corresponding generation levels under the various PoA investigated.

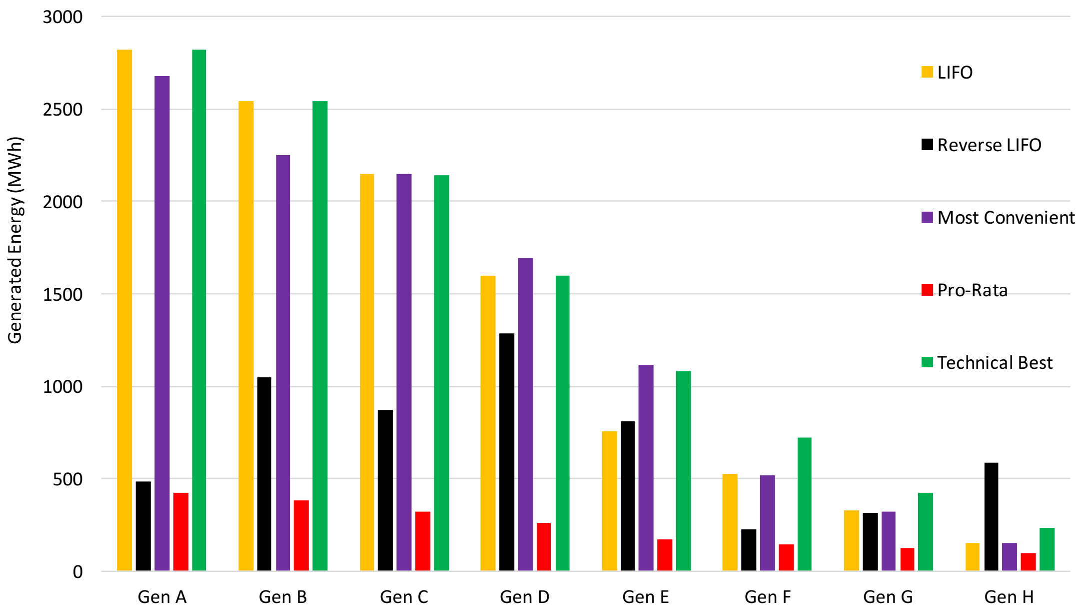


Figure 3.9: Performance of DG units under PoA

In this case-study network, Pro-Rata arrangement is seen to be unfavourable for all the wind farms in terms of generation levels where voltage constraint is binding. Pro-Rata arrangement on the other hand have been widely applied in a number of UK ANM schemes (e.g. Flexible Plug and Play project) for sharing curtailment at thermally constrained networks. It may become suitable to future distribution network applications where the generators are compensated for curtailing their power generation or network conditions where the system objectives are different (e.g minimum losses). Here in this case-study network configuration, it is assumed that all the DGs receive equal compensation for being constrained off.

Reverse LIFO arrangement is observed to favour the remotely located generators (Gen H for instance) and does not favour majority of the wind farms. Reverse LIFO arrangement where voltage constraint is binding could become useful for small rural community and islanded networks where the lines have similar X/R ratios and characteristics such that, the DGs active generation impact on the voltage profiles would be similar.

LIFO and Most Convenient arrangements are seen to favour a number of the DG schemes and are both observed to offer competing benefit to the wind farms. LIFO will be most beneficial to the wind farms when the criteria adopted and implemented under this case study is maintained for future distribution network operations. In contrast with real UK distribution networks, LIFO is implemented via the date of DG connections to the network and could prove less favourable for the wind farms when voltage constraint is binding as discussed in [66]. Most Convenient on the other hand provided competitive benefit to a number of the DG schemes as the criteria for implementing it was system operator led and primarily based on feeder lengths as a convenient method to optimally share network capacity that minimises DG curtailment.

Technical Best arrangement is seen to provide the most economic benefit to majority of the wind farms when the network is managed under voltage constraint conditions. Here, all the wind farms have equal priority access to the network. This arrangement fully utilises active curtailment techniques by assessing available online network capacity and allowing the optimisation engine to optimally allocate curtailment in order of wind farm's contributions to the constraint. The optimisation takes full account of the impact of the DGs on the constraint based on their various geographical locations.

3.4.7.1 Assessment of principles of access against criteria

Table 3.3 presents a qualitative assessment of the PoA techniques against the criteria discussed earlier in section 3.3.1 of this thesis. The objective established in this case-study network is to maximise wind farm connection capacities using suitable PoA. Five different PoA arrangements have been investigated earlier in this section to assess the rules for connecting non-firm DGs when managed under network voltage constraint conditions. Here in this section, the qualitative assessment undertaken is primarily based on the outcome of the case-study and the underlying system objective. In real distribution network applications, the criteria under which the PoA are assessed and evaluated may differ and therefore assessment undertaken in this thesis may only be used as a guide. Scoring points are awarded for each assessment criteria the PoA meets. A scale of 1 to 5 is used, where 1 represent the lowest scale and 5 represent the highest scale. A summation of the points awarded is provides at the far right-hand column as shown in Table 3.3.

Table 3.3: Assessment of principles of access

Principles of Access	Comply with Grid Code	Network Efficiency	Certainty	Clear and Transparent	Simplicity	Support Safe, Secure and Reliable System	Fairness	Gain Support of all Stakeholders	Learning	Robustness	**Total**
LIFO	5	3	3	4	3	4	3	3	3	3	**34**
Reverse LIFO	5	1	2	2	2	4	2	2	3	1	**24**
Most Convenient	5	3	3	3	4	4	3	3	4	2	**34**
Pro-Rata	5	1	1	1	3	4	1	1	2	1	**20**
Technical Best	5	4	3	5	4	4	4	3	4	4	**40**

Pro-Rata is recorded as the least scored points out of the rest of the PoA investigated as it does not fully maximise network efficiency, causes unfairness to capacities of economically viable generators and as a result unlikely to gain support from all stakeholders. Reverse LIFO is recorded the second least scored points as it does not fully maximise network efficiency and is therefore not considered a robust method to optimally share curtailment.

LIFO and Most Convenient arrangements are scored equally and are seen as likely techniques that can be applied to share curtailment on similar networks. Technical

Best arrangement is observed with the highest scoring points when compared with the rest of the PoA investigated. It is seen to maximise network efficiency, it is clear and transparent as curtailment is optimally shared in order of the impact of the DGs active power injections on the voltage profiles. Technical Best is simple and straightforward to implement as all the DGs have equal priority access to the network and does not on depend on appropriate arrangement of a priority stack. It is robust, supports network operations and will ensure a safe, secure and reliable power system.

On the contrary, whilst Technical Best PoA arrangement is seen to score the highest points by offering efficient network operations is unlikely to gain full support of all stakeholders and may cause some uncertainties for existing DGs as new non-firm generators (NNFG) connect to the network. The complexities of voltage rise constraint issues and network operations may complicate the curtailment scenario and cause confusion. This will become apparent when the NNFG are connected to the strong sections of the network. This may lead to existing DGs located at the weak sections of the network to experience further curtailment. These changes in conditions and network operations are further investigated and modelled in Chapter 7 of this thesis to assess the suitability of the PoA under such changes. To implement fairness among the existing and new wind farm connection, a cap may be set to guarantee a minimum generation level (say 20% for all DGs) before curtailment is optimally shared using a Technical Best criteria.

3.5 Summary

The deployment of smart solutions on the electricity networks will help to accommodate, facilitate and increase the connection of low carbon technologies. Implementing smart solutions implies optimising network use and controlling generation resource and as such, requires the development of smart commercial arrangement to connect the non-firm generators. Developing smart commercial arrangement involves smarter ways to manage the amount and frequency of curtailment in order to provide system reliability, minimise social costs (i.e. negative prices that are incurred by end customers) and attract greater DG investment. The challenge here usually lies in identifying smarter arrangements that are (1) cost-effective for DNOs and DGs (2) economically efficient (making the best use of the network - reduce costs of given DG for consumers) and (3) socially efficient (maximising social welfare including carbon price and the social value of more connected renewables).

This section of the thesis has presented active power curtailment as an ANM tool to control distribution network voltages. It has studied the sharing of curtailment and limited network capacity across multiple non-firm wind farms by applying and testing the suitability of existing PoA arrangements (currently implemented on thermally constrained networks) under network voltage constraint conditions. It has addressed the case-study questions and was observed that, when the same PoA techniques are applied under voltage constraint conditions, the benefit and impact on the wind farms are not the same. Network voltage rise issues in itself is a local area problem at the point of DG connections and the magnitude of the constraint depend on the strength of the network at the vicinity of the DG. The dynamics of voltage rise constraint issues on the network is practically complex and significantly differs from thermal constraint issues. Under network operations where thermal constraint is binding, all the DG units are considered equal contributes to the constraint irrespective of their location and strength of the network adjacent. However, the same conditions are not true when voltage constraint is binding. The significant difference in the dynamic behaviour of both voltage and thermal constraint limitation problems on the distribution network imply that, the philosophy for sharing curtailment will also behave differently.

There is now an increased need to develop new smart commercial arrangement that enhances DG connection capacities in a timely and cost effective manner whilst minimising network constraints. This will become beneficial especially for future network applications where both voltage and thermal constraints are binding. To overcome the current network limitations there is a need to develop new and viable PoA strategies that ensures better utilisation of the existing network asset to make ANM schemes competitive with traditional network reinforcement solutions. This will help strengthen the confidence needed for both network operators and future wind farm developers. This will also be coupled with a comprehensive revision of the current regulatory framework and standards that governs the connection of DGs.

Chapter 4

DISTRIBUTION VOLTAGE CONTROL THROUGH OPTIMISED OPERATION OF ON-LOAD TAP CHANGING TRANSFORMERS

4.1 Introduction

The studies undertaken in Chapter Three presented active power generation curtailment as an active network management (ANM) tool to control distribution network voltages. This section utilises the distribution network asset such as, on-load tap changing (OLTC) transformer operations installed at the primary substation to control the voltages and to improve network hosting capacity. The current operational practice of most DNOs in the UK is to set the reference voltage at the primary substation at 1.02 p.u to control the secondary voltages. This section investigates an optimised set-point voltage control technique of the OLTC transformer with aim to enhance DG voltage margins and to improve network hosting capacity.

4.2 Basic operation of on-load tap changing (OLTC) transformers

On-load tap changing transformers are the most common control device in power system applications to regulate and maintain distribution network voltage within required limits. For many decades, power transformers equipped with on-load tap changers (OLTC) have been the main component of electrical networks and industrial applications for nearly a century [131]. The OLTC transformer allows voltage regulation and/or phase shifting on the network by varying the transformer turns ratio under load without interruptions. Centralised voltage control methods at distribution networks have traditionally relied on OLTC transformers as the most common control device to regulate and maintain network voltages within required limits [21]. In the UK, the statutory voltage limits are defined in the Electricity Safety, Quality and Continuity (ESQC) Regulations 2002 [132] and it specifies that, low voltage (LV) customers be supplied at 400/230 V with tolerance of $+10/-6\%$, whereas high-voltage (HV) customers, at tolerance of $\pm 6\%$. The OLTC operates by moving their tap positions to select appropriate transformer turns ratio that suits a range of power flow conditions on the network.

To simplify and automate voltage regulation, automatic voltage control (AVC) relays which are usually referred as the brain of the OLTC system [38] are used in conjunction with line drop compensation (LDC) equipment. The AVC relay continually monitors the network to detect voltage variation and initiates a tap change command to the motorised OLTC when the voltages are outside the pre-set limit [42]. The AVC relay operation usually incorporates a time delay setting between 10 and 120 s from detecting an out of range voltage and starting a tap-change command. The time-delay setting is to avoid unnecessary tap operation during short-term voltage fluctuations on the network. The LDC is used to compensate for voltage drop variations on the line between the transformer and loads situated towards the far end of the feeder.

4.2.1 Design principles and arrangement of OLTC transformers

The OLTC operates by changing the ratio of the transformer by adding or subtracting turns from either the secondary or primary windings. The transformer is equipped with a regulating or tap windings connected to the OLTC [133]. The voltage between tapping positions usually referred as the step voltage normally lies between 0.8% and 2.5% of the transformer rated voltage [21]. The tap change operation may be motor driven or manually operated by a switch [134].

From the inception of OLTC transformers in power network applications, two main switching mechanisms have been implemented for load-transfer operations on the network and are based on either a slow-motion reactor principles or a high-speed resistor principle. The reactor-type are commonly used in North America on the low-voltage winding whereas; the resistor-type are normally used in Europe on the high-voltage winding [135]. Throughout these years, both switching mechanisms and operational principles have been developed into reliable transformer components to cover the needs of today's network and industrial applications to ensure optimum system performance.

4.2.1.1 Resistor-type

Majority of the resistance-type OLTCs are usually installed inside the transformer tank and can be referred as in-tank OLTCs. The resistor-type are the most common OLTC transformers used in Europe. It employs a selector mechanism that makes connections to the winding tapping contact and a diverter or an arcing switch mechanism which controls the current flow while the tap-changing is taken place. Figure 4.1 provides an illustration of a OLTC transformer comprising of an arcing switch and tap selector principle. At normal operations, the selector and arcing switch mechanism may be combined or separated depending on the transformer ratings [135].

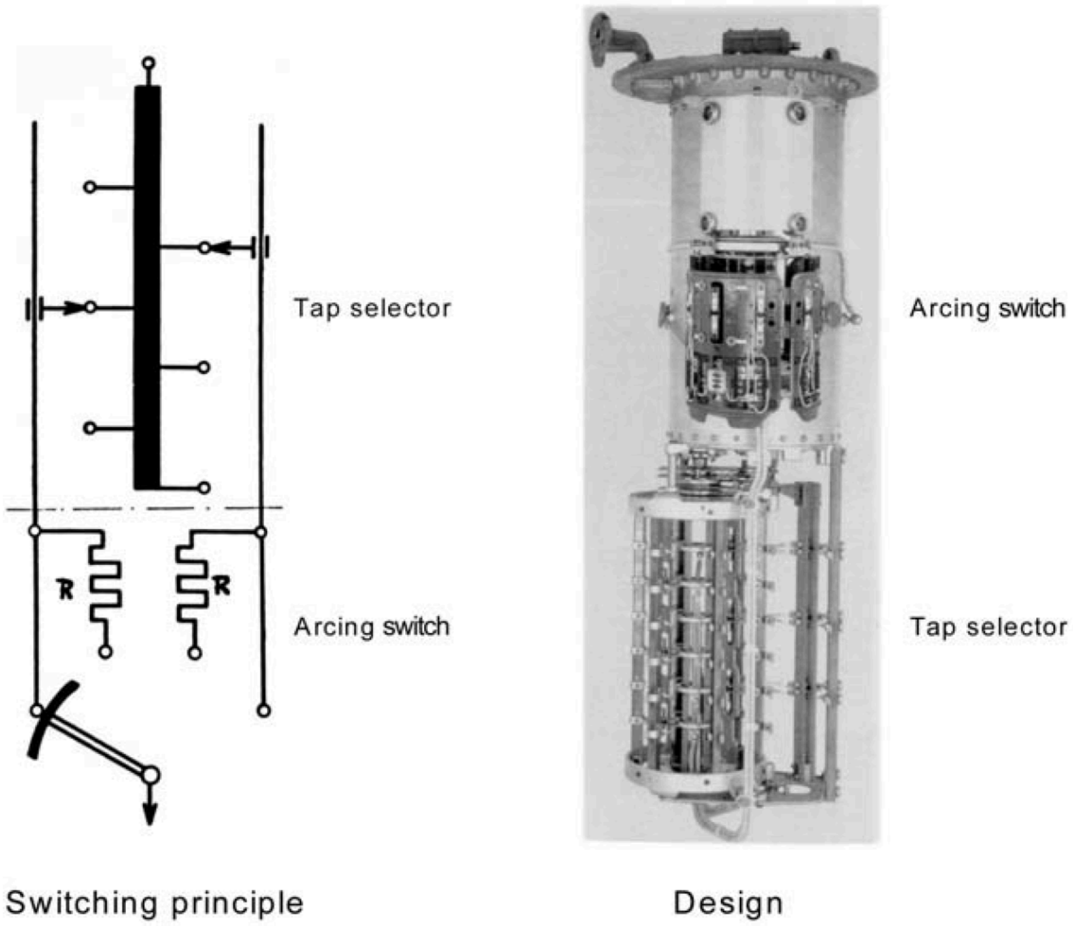


Figure 4.1: Arcing switch with tap selector [131]

OLTC transformers comprising an arcing switch and tap selector, the tap change takes place in two steps. Figure 4.2 illustrates the switching sequence of the tap change selector and arcing switch mechanism. The overall purpose is to transfer connection from the selected tap to a preselected adjacent tapping without interrupting the power supply to the load.

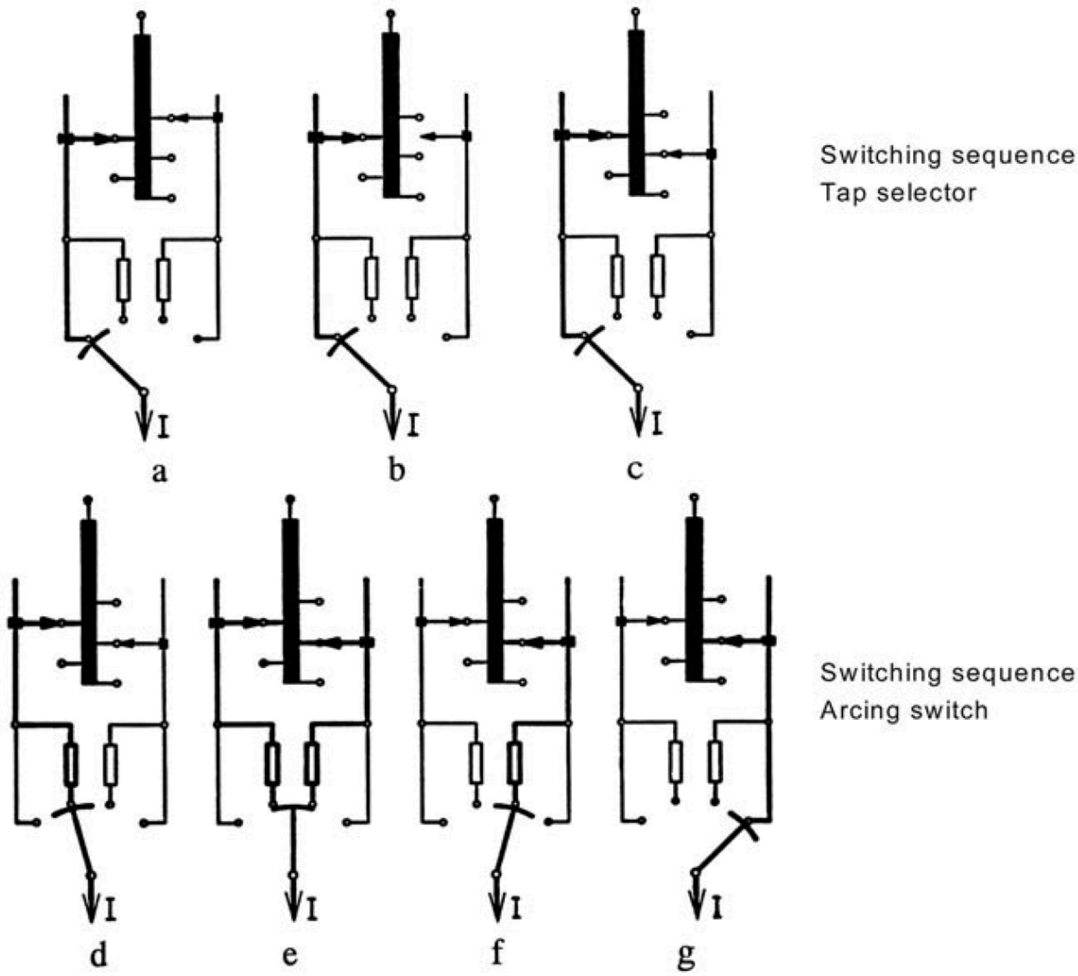


Figure 4.2: Switching sequence of arcing switch with tap selector [131]

The first step in the OLTC transformer operation involves preselecting the next tap using the tap selector at no load conditions. This arrangement is illustrated in Figure 4.2 (positions a - c). The arcing switch then transfers the load current from the tap in operation to the preselected tap as shown in Figure 4.2 (positions c - g). The OLTC transformer is operated by a motor drive mechanism. The tap selector operates by gearing directly from the motor drive and the spring accumulator becomes tensioned. The spring accumulator operates the arcing switch within a very short time interval, independently of the motion of the motor drive. The gearing system ensures that the arcing switch operation always occurs after the tap preselection operation has been completed. With today's modern design principles, the switching duration of an arcing switch mechanism usually lies between 40 and 60 ms.

During the arcing switch operation, transition resistors are inserted (Figure 4.2 positions d - f). These are loaded for 20 - 30 ms and since they only have a short-time loading duration, the amount of material required are very minimal. The total operation time of a conventional OLTC transformer normally lies between 3 - 10 seconds, depending on the respective design.

4.2.1.2 Reactor-type

The reactance-type OLTC transformer is usually in a separate compartment that is normally welded to the transformer tank. The following switching mechanism typical of the reactance-type are used: This is elaborated in Figure 4.3.

- Selector switch (arcing tap switch)
- Arcing switch with tap selector

In Figure 4.4, a selector switch (arcing tap switch) carries out the tap-change in one step from the tap in service to the adjacent tap. The spring energy accumulator, wound up by the drive mechanism actuates the selector switch sharply after releasing.

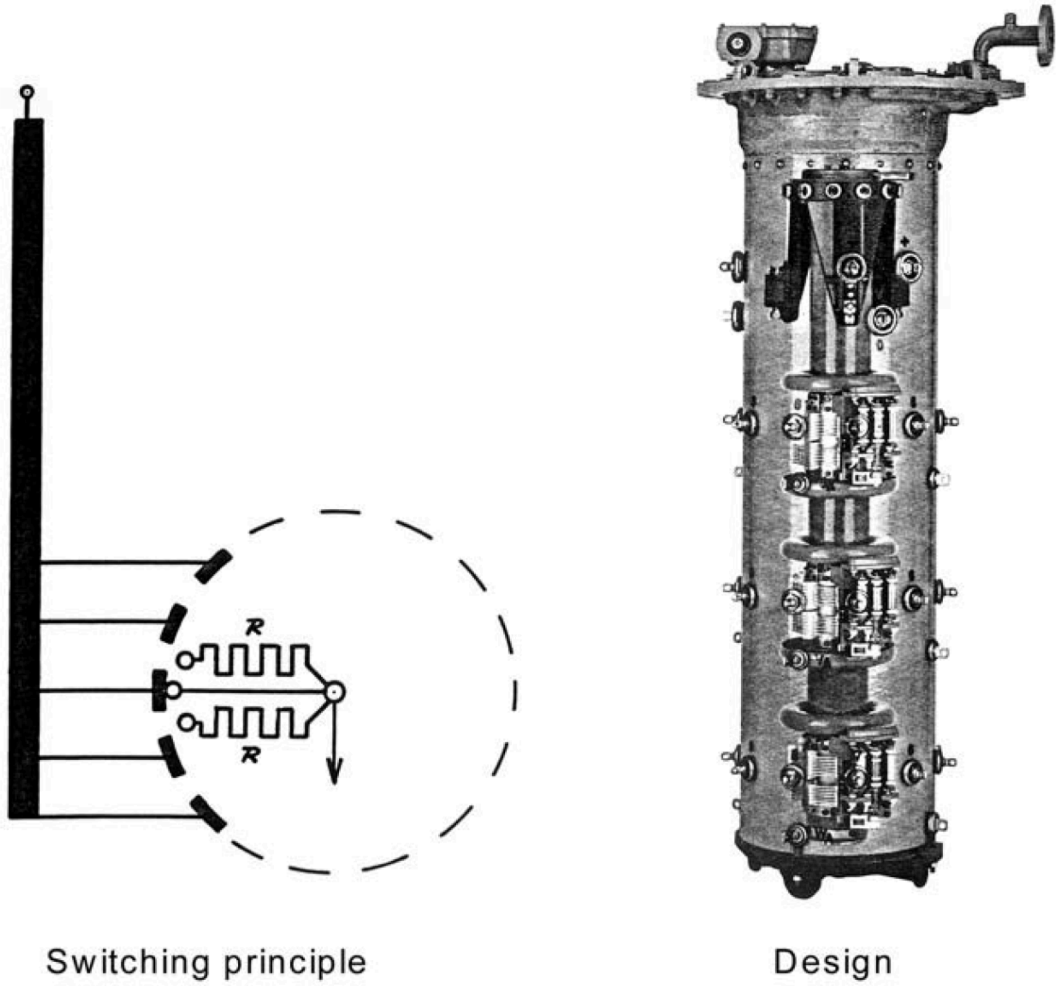


Figure 4.3: Arcing tap switch [131]

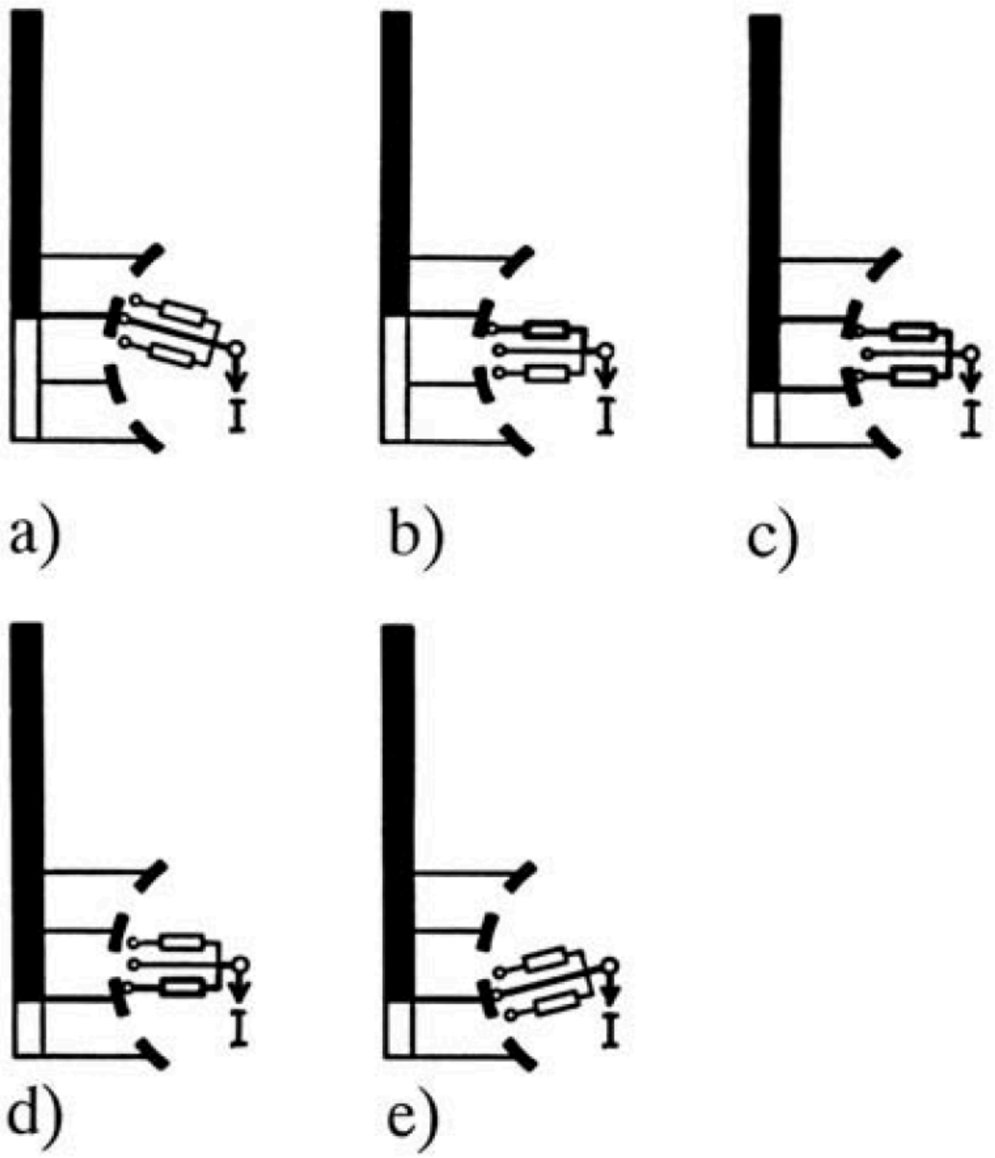


Figure 4.4: Switching sequence of arcing tap switch [131]

All reactor-type OLTC transformers are compartment types where the preventive autotransformer (reactor) is not part of the OLTC design arrangement. The preventive autotransformer is designed by the transformer manufacturer and located in the transformer tank.

4.3 OLTC transformer as an ANM tool to improve network hosting capacity and control voltage

This chapter utilises the distribution network asset such as, on-load tap changing (OLTC) transformer operations installed at the primary substation to control the voltages. It implements a coordination of ANM tools involving centralised OLTC transformers and area-based generation curtailment at the point of connection to control the voltages. The study investigate optimum set-point voltage control technique of the tap-changing transformer with aim to improve network hosting capacity to accommodate greater wind farm connections. It provides the first study to address the voltage rise problem through the application of optimised set-point techniques using ACOPF analysis methods. The proposed control technique is formulated as an optimisation problem that makes use of mathematical ACOPF analysis tools using time-series simulations similar to the methods implemented in Chapter 3. It utilises the standard ACOPF [123, 124] formulation at each time-step and treats the tap position as control variables. The optimisation technique enhances DG voltage margins and minimises the impact of active generation on voltage profiles. It provides the first study that models an optimum operating range of the tap change transformer using OPF techniques with objective to minimise the operation of the transformer tap-changer to control the voltage whilst optimising DG active generations within the specified network constraint.

The ACOPF formulation in this case-study involves a two-stage optimisation process that treats the tap positions as discrete and continuous control variables similar to the methods discussed in [136] and [137]. The initial stage is a discrete method which models the voltage step ratio as discrete variables that can vary between a certain maximum V_s^{max} and minimum V_s^{min} set-point voltage by a fixed step-size Δv. Here, the AVC controller model manually moves up or down by one step size Δv at a time and locks the transformer tap position to a pre-determined voltage set-point. Each optimisation cycle requires a physical movement of the tap position to the desired set-point, where the voltage is held fixed at the slack bus to connect the multiple wind farms. The control logic can be expressed mathematically as:

$$V_s = \begin{cases} V_s + \Delta v & \text{if } |V_k - V_{ref}| < \Delta m \quad \text{and } V_s < V_s^{max} \ ; \quad V_s^{max} = V_s^{min} \\ V_s & \text{if } |V_k - V_{ref}| < \Delta m \quad ; \ V_s^{max} = V_s^{min} \\ V_s - \Delta v & \text{if } |V_k - V_{ref}| < \Delta m \quad \text{and } V_s > V_s^{max} \ ; \quad V_s^{max} = V_s^{min} \end{cases} \tag{4.1}$$

where V_s represents the set-point voltage at the slack bus, the regulated voltage quantity, V_{ref} is the reference voltage, and Δm represents the AVC relay operating range. The ACOPF discrete model investigates a narrowed operating range that aim to optimise the wind farm generation capacities within the specified network constraints. Within this narrowed operating range, lies an optimum voltage set-point.

In the second stage, the narrowed AVC operating range is modelled into the OPF and treats the transformer tap positions as continuous variables. The continuous method assumes a small tap step ratio Δv and models the discrete switches as approximated continuous variation of the set-point voltage V_s. In this case, the ACOPF can choose optimum set-point values between the narrowed upper maximum limit $V^{max}_{s_{(optimised)}}$ and lower minimum limits $V^{min}_{s_{(optimised)}}$ that maximises the objective function at each iteration. This can be represented mathematically as:

$$V^{min}_{s_{(optimised)}} \leq V_{s_{(optimised)}} \leq V^{max}_{s_{(optimised)}} \tag{4.2}$$

4.4 Implementing OLTC transformer voltage control using a case-study network

In this section, the voltage rise problem is addressed and mitigated by testing the OLTC voltage control technique on a realistic UK generic distribution network. The case study investigates optimal set-point voltage control technique of the OLTC transformer that aim to improve network hosting capacity to accommodate high wind penetration levels. A coordinated ANM solution involving OLTC transformer operations and area-based active power generation curtailment is implemented to control the network voltages.

The case-study implements the techniques and presents a detailed assessment of the benefit and impact on DG capacities.

4.4.1 Case study questions

The case study utilises existing distribution network assets such as; on-load tap changing transformer operations installed at the primary substation. It applies non-linear programming optimisation methods that treats the tap-positions as both discrete and continuous variables to control the network voltages and enhance DG connection capacities. The optimisation methods used is to analyse the case study and specifically to answer the following key questions:

1. How can we mitigate the voltage rise limitation problem in active distribution networks using existing network asset such as OLTC transformer operations?
2. Can this operation be coordinated with other ANM tools such as active power curtailment to minimise the impact of wind generation on the voltage profile?
3. Can we investigate an optimum operating range of the AVC relay that minimises the number of tap changing operations of the OLTC transformer to enhance the life-span and reduce the cost of maintenance.

4.4.2 Network description

The operation of voltage control utilising existing network assets such as OLTC transformer at the distribution primary substation is applied to a representative UK generic distribution test network (UKGDS) [HV UG-OHb] [118] described earlier in Chapter 3. The model is deployed in Matpower [122] and time-series simulations are performed over a month period at half-hourly resolution, consisting a total of 1440 time-steps. The principle of access rule for connecting the multiple distributed wind generators and sharing of curtailment is via a Technical Best arrangement. Here, all the wind farms are assumed to have equal priority access to the constrained network. In this rule, the OPF engine optimally shares limited network capacity by assigning greater curtailment in order of the wind farm's contribution and impact on the constraint.

4.4.3 Problem formulation

In this case-study, the voltage rise problem is addressed and mitigated. It also utilises active curtailment techniques of wind generators as an ANM tool to maintain the network voltages when the limits are breached. Previous work reported by [138] involved an area control strategy of the OLTC transformer operation using local network measurement. The authors used voltage information of remote measurement points to determine optimal tap positions that minimises voltage deviations on the network. This was achieved through heuristic-based optimisation methods which treated the tap changer as discrete variables. A decision-making algorithm is proposed in [139] to find adequate set-point voltage generated through simulations or historical performances to control voltage rise using OLTCs. In [42], the authors discuss voltage regulation using a coordination between OLTC and line drop compensation in medium-voltage feeders to improve DG connection capacities.

A similar area-based coordinated control strategy that regulates the voltage set-points of the AVC relay at the primary distribution substation have been studied in [81] using time domain simulations. The authors investigated the dynamic operation of the AVC relays and tap changing mechanism of the transformer in response to the system load variation. The authors implemented a control algorithm that regulated the set-points of the AVC relay at the primary substation and the operation tested on an example network using PSCAD simulations. In [136], the authors discuss an interior point (IP) optimisation method based on a non-linear complementarity model for OPF problems with load tap changes. The authors initially treat the tap positions as continuous variables to identify the upper and lower bounds of the transformer using OPF. The complementarity constraints of the transformer taps are then modelled into the OPF and solved using IP optimisation. The optimisation in this case-study network aims to achieve the following system objectives:

1. maximise wind generation output
2. minimise the number of OLTC transformer tap operations

4.4.4 Automatic voltage controller (AVC) set-point voltage philosophy

To demonstrate and quantify the effectiveness of the proposed strategy to mitigate the voltage rise problem, five scenarios for connecting the multiple wind farm schemes have been investigated and are summarised in Table 4.1.

Table 4.1: Summary of AVC set-point voltages

Scenario	%	kV	p.u
1	+3	11.33	1.03
2	+2	11.22	1.02
3	+1	11.11	1.01
4	0	11.00	1.00
5	-1	10.89	0.99

Each scenario configures the set-point voltage of the AVC relay associated with the OLTC transformer to a pre-determined fixed target value to control the network voltages. It assesses the adequacy of adjusting the set-point voltages to improve the network hosting capacity and the impact of these adjustments on the wind farms.

The model is deployed in Matpower [122] which uses interior point method (IPM) for the constraint nonlinear programming (CNLP) problem. Time-series simulation are performed over a full month period at half-hourly resolution and consists a total of 1440 time-steps. Each scenario provides a quantitative assessment of the renewable energy yields and subsequent curtailment levels required to maintain the network limits. In this study, -2% and -3% set-point voltages are ignored as a result of undervoltage conditions occurring towards the ends of the feeders at certain time-steps during the time-series simulation. In these scenarios, the ACOPF failed to converge due to breach of lower voltage limits at certain time-steps.

4.4.5 Case study results

This section presents the scenarios studied and discusses corresponding simulation results obtained. Using adaptive ANM technological solutions, this section demonstrates voltage control and the impact on the wind farms when the set-point voltage technique (of the OLTC transformer) is implemented. The case study makes the following economic viability assumptions:

1. The non-firm capacity of each generator is defined as economically viable if it has a minimum generation capacity of 30% .
2. That is if no curtailment is applied, the maximum generation capacity of each wind farm corresponds to 100%.

4.4.5.1 Scenario 1: Set-point voltage fixed at +3% of nominal

This scenario represents the worst-case operation condition of the AVC set-point voltage. In this study, the set-point voltage at the slack bus is raised and held fixed at the upper maximum limit (+3% of nominal) which serves as a reference to the rest of the secondary bus voltages, the result obtained is shown graphically in Figure 4.5.

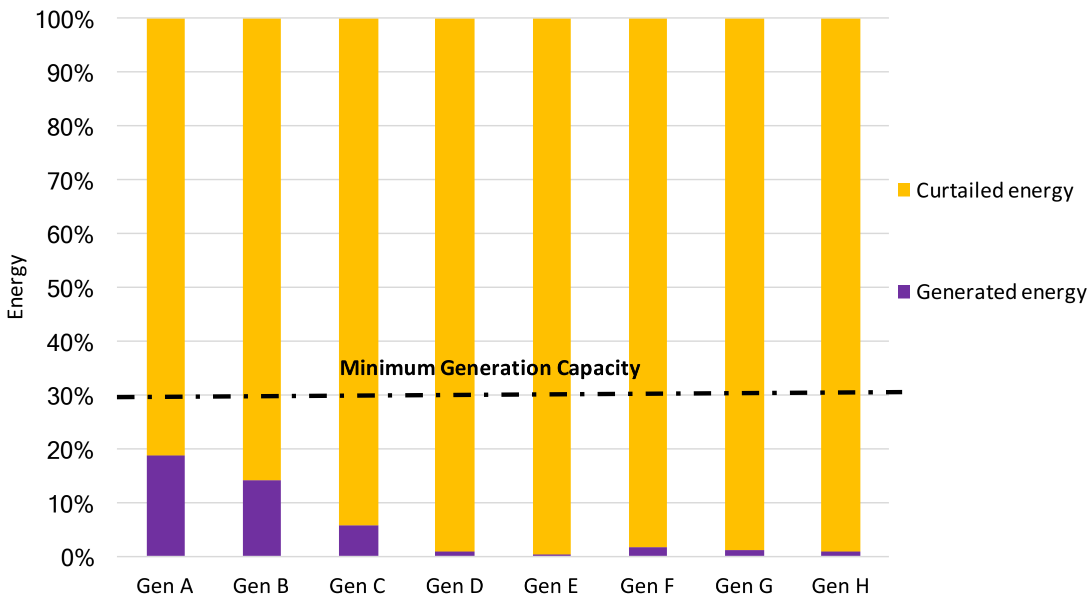


Figure 4.5: Energy generated and curtailed at +3% set-point voltage

The ACOPF reveals poor DG performances in terms of generation levels. Gen A (10 MW) which is the biggest size DG and electrically the closest to the primary substation is observed to be generating a maximum capacity of 19%. In comparison to Gen H (2.3 MW) which is the smallest and electrically the most furthest away is observed to be generating a maximum capacity of 1%. All the other wind farms in this configuration are observed to be operating below the minimum economically viable generation capacity of 30%. The wind farm generators are seen to experience significant curtailment due to low voltage margins and limited network headroom capacity. As a result, active generations from the wind farms becomes highly susceptible to causing voltage rise issues and raising the network voltage profiles beyond the maximum upper limit. The breach in network voltage limits due to active power injections from the wind farms forces the OPF engine to heavily curtail the generators to levels that maintains the constraint.

4.4.5.2 Scenario 2: Set-point voltage fixed at +2% of nominal

In this scenario, the operation configuration of the AVC set-point voltage is fixed at +2% of the nominal voltage. The set-point voltage condition at the primary substation serves as a reference to the rest of the secondary bus voltages and the result obtained is shown graphically in Figure 4.6.

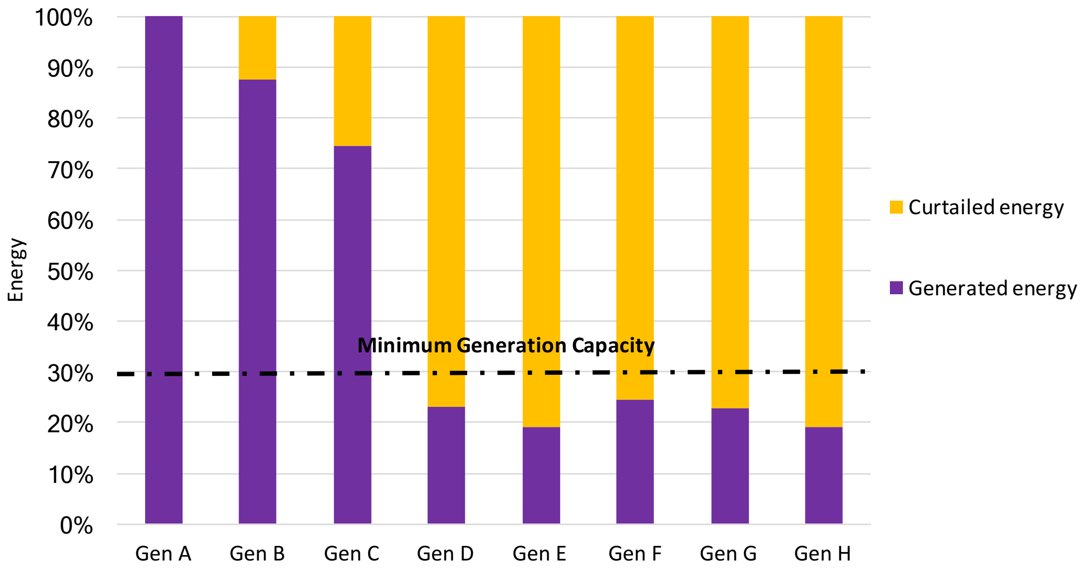


Figure 4.6: Energy generated and curtailed at +2% set-point voltage

At the end of the ACOPF simulation, generator A (10 MW) located at a strong section of the network is observed to be operating at full installed capacity. Generators B (9 MW) and generator C (7.6 MW) also located at the strong sections of the network are observed to be operating above the minimum economically viable limit of 30%. The rest of the wind farms are seen to operate below the minimum economically viable limit due to low voltage margins of the generators.

4.4.5.3 Scenario 3: Set-point voltage fixed at +1% of nominal

In this scenario, the set-point voltage is lowered and held fixed at +1% of the nominal and the result obtained is shown graphically in Figure 4.7.

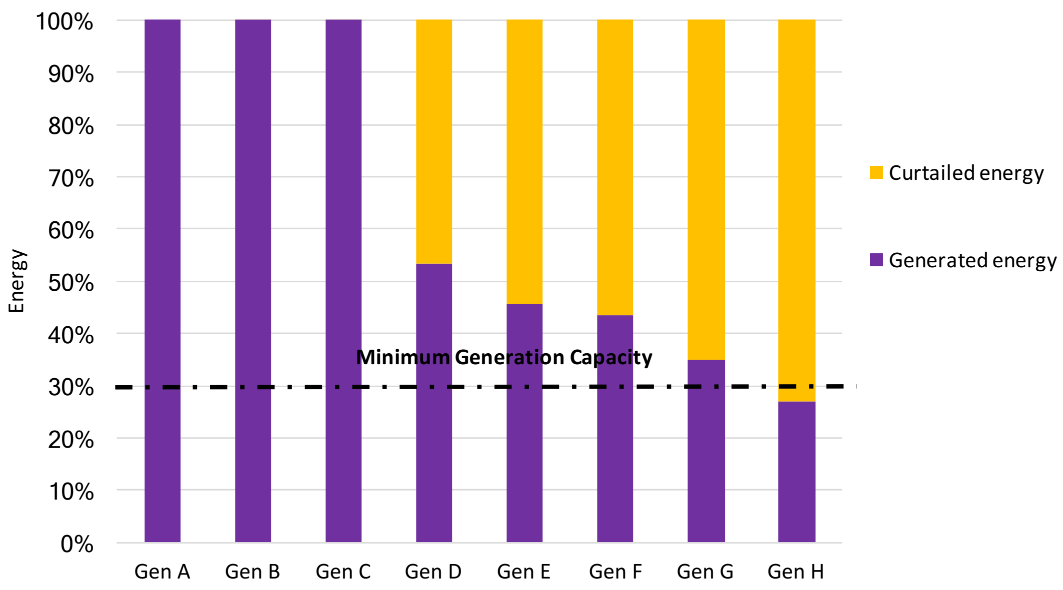


Figure 4.7: Energy generated and curtailed at +1% set-point voltage

The ACOPF results at the end of the simulation shows improved generation levels of the DGs with generators A (10 MW), B (9 MW), and C (7.6 MW) observed to be operating at their maximum installed capacities. Subsequently, the OPF allows an improved access for the rest of the wind farms to generate onto the network with generators D (6.1 MW), generator E (4.1 MW), generator F (3.4 MW) and generator G(3 MW) operating above the minimum economically viable limit. Generator H (2.3 MW) is observed to be operating up to a maximum of 27% of its rated capacity which is below the minimum economic viability limit.

4.4.5.4 Scenario 4: Set-point voltage fixed at 0% or nominal

This scenario sets and fixes the AVC set-point voltage at the nominal. This scenario represents the default operation condition of the AVC set-point voltage and the result obtained is shown graphically in Figure 4.8.

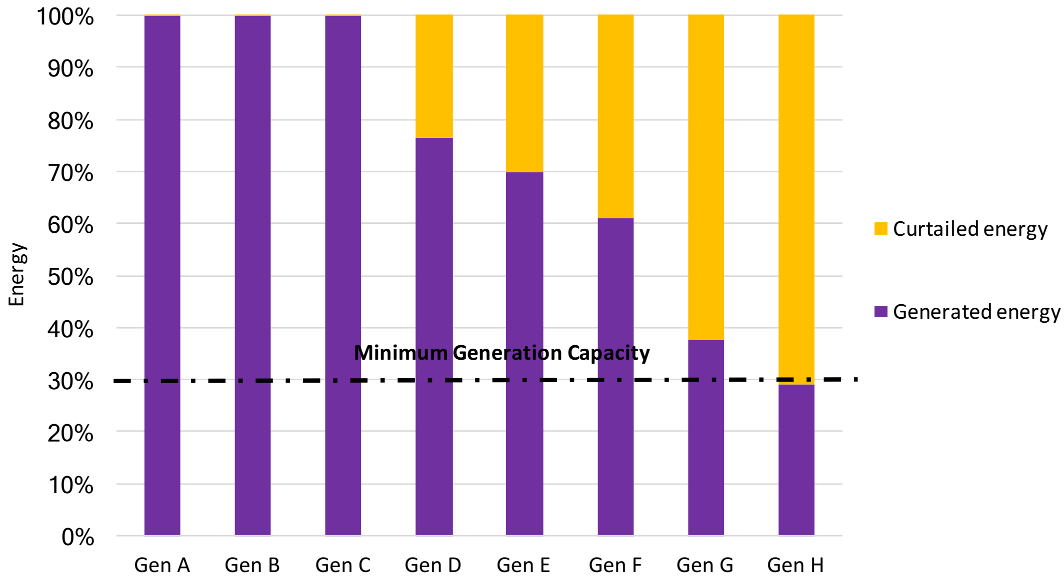


Figure 4.8: Energy generated and curtailed at 0% set-point voltage

The ACOPF results reveals improved generation capacities of the wind farms with generators A (10 MW), B (9 MW), and C (7.6 MW) observed to be operating at maximum installed capacities. Generator D (6.1 MW), generator E (4.1 MW) and generator F (3.4 MW) are seen to operate above 50% of their installed capacities. Generator G(3 MW) is observed to be operating at a maximum capacity of 38% which is above the minimum economic viability limit. Generator H (2.3 MW) is observed to be operating at a maximum capacity of 29% which is below the minimum economic viability limit.

4.4.5.5 Scenario 5: Set-point voltage fixed at -1% of nominal

Here, the set-point voltage is further lowered to -1% of the nominal voltage and the result obtained is shown graphically in Figure 4.9

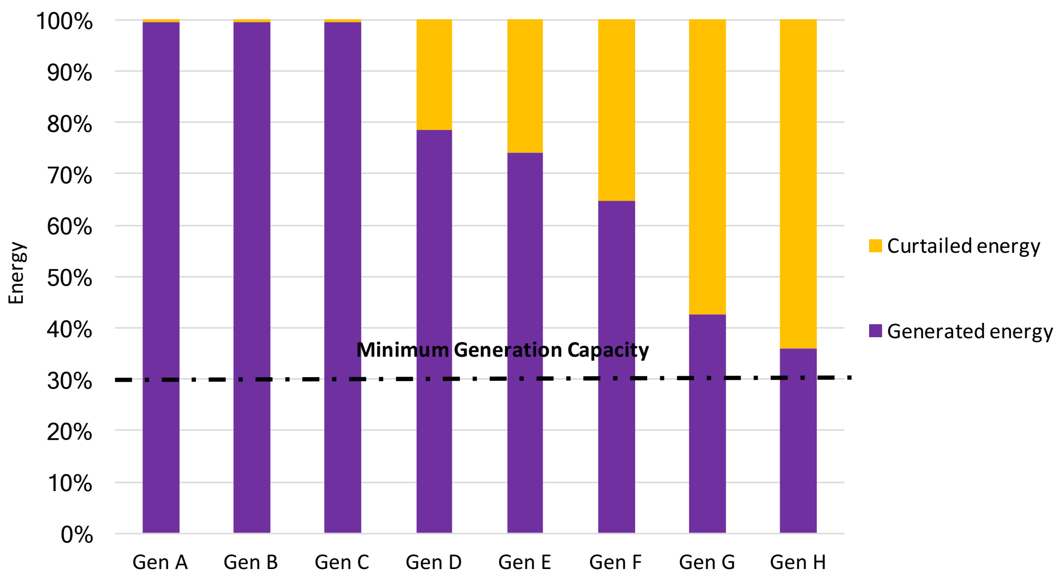


Figure 4.9: Energy generated and curtailed at -1% set-point voltage

Simulation results obtained at the end of the ACOPF shows significant improvement in generation capacities allowing the remotely connected wind farms, greater access to the network and subsequent increase in wind energy yields. Generators A (10 MW), B (9 MW), and C (7.6 MW) are observed to be operating at maximum installed capacities. Generator D (6.1 MW), generator E (4.1 MW) and generator F (3.4 MW) are seen to operate above 50% of their installed capacities. Generator G(3 MW) is now observed to be operating at a maximum generation capacity of 43%. Generator H (2.3 MW) is observed to be generating up to a maximum capacity of 36%. In this scenario, all the DG units are observed to be operating above the minimum economically viable limit of 30%.

4.4.6 Case study discussion

In this study, the OPF optimisation engine controls and dictates the amount of energy generation and curtailment according to the wind farm's active power impact on local voltage rise constraint at the point of connections (POC). The total energy realised across the investigated set-point voltages is presented in Figure 4.10. From here it is seen that, the overall energy generation across the DG schemes increases by lowering the OLTC transformer set-point voltages at the primary substation. Operating the AVC relay at high set-points significantly reduces generation capacities. For example, at +3% set-point voltage, a total energy yield of 1071 MWh was realised out of 12,851 MWh available energy corresponding to a total generation capacity of 8.3% across the DG units. In the case of −1% set point voltage, a total generation of 10,909 MWh was realised out of the total available energy representing an improved generation capacity of 85% across the DG schemes.

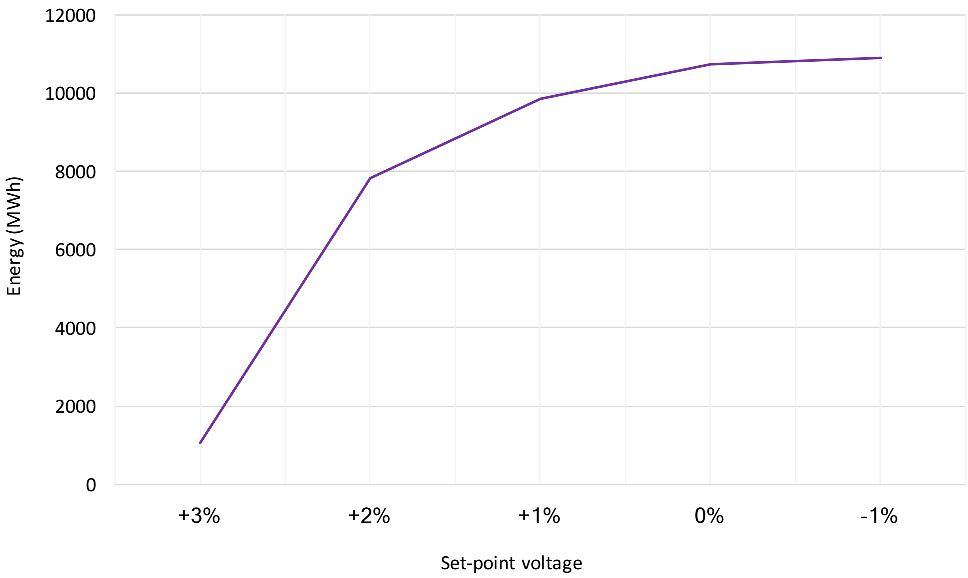


Figure 4.10: Total energy generation across set-point voltages

Setting the AVC relay at high-voltage set-points adversely limits the distribution network's headroom capacity to cope with high generation levels from the wind farms. In effect, active generation from the wind farms become highly susceptible to pushing the networks voltage profiles above the maximum limits forcing the OPF to heavily curtail generations to levels that satisfy the constraint. In such extreme cases, generators located at the strong sections of the network (with minimum impact on voltage rise constraint) are allowed greater access to the constrained network. Remotely located wind farms connected to the weak sections of the network in this case have restricted or no access to the network as seen in Figure 4.5. Therefore, to influence fairness and greater connection capacities for all the wind farms across the various network location points, network operators have a scope to lower the voltage settings at the primary substation to enhance DG voltage margins and allow greater active generation capabilities. By doing this, the voltage profiles and network headroom capacity can be improved to accommodate high wind penetration levels.

Generator performance profiles across the investigated set-point voltages are presented in Figure 4.11. From here, it is observed that the wind farms generation capacities decrease as we move further along the feeders and away from the primary substation. Wind farms located closer to the primary substation showed greater penetration levels across all voltage set-points when compared with the remotely located wind farms. For instance, at +3% set-point, it seen that generators A, B, and C are highly favoured with greater network access due to their strong location. The rest of the wind farms are least favoured (with highly restricted or no access to the network) due to their weak and remote location.

Future operation conditions of the network will involve large wind farms connecting further away from the primary substation. In such cases, similar results will be obtained as the DG voltage margins traditionally decreases as we move further away from the primary substation towards the remote ends of the feeders where weak strength of network prevails. However, it is seen that the OPF allows an improved access for all the wind farms when the set-point voltages are lowered to levels that minimises their active power impact on voltage rise constraint.

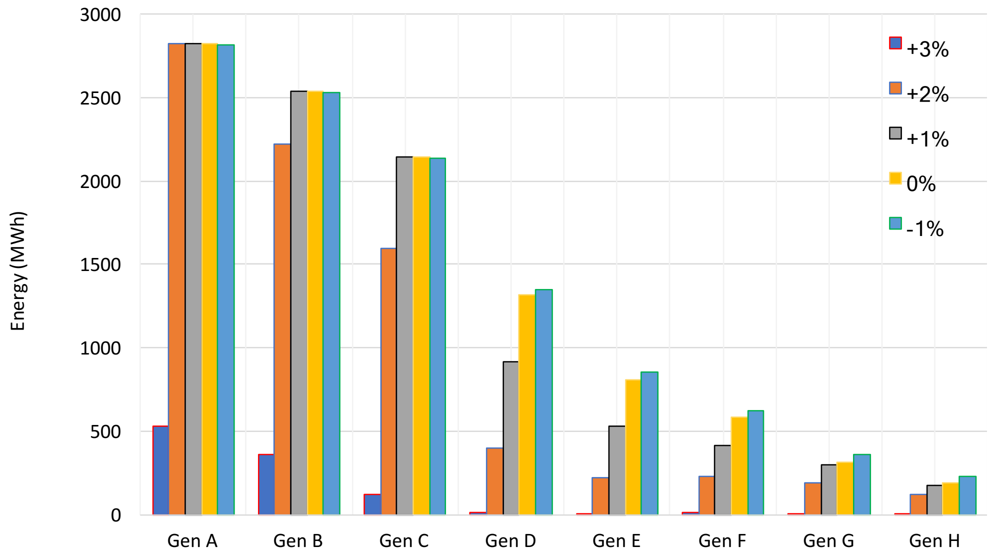


Figure 4.11: Generator performance profile

Figure 4.12 shows profiles of the maximum bus voltage magnitudes recorded during the optimisation. Here, by comparing the voltage profiles of selected set-point voltages such as, scenarios 1, 3, and 5, it is seen that operating the AVC relay at -1% set-point voltage improves the voltage profile and mitigates the voltage rise problem. The maximum voltage profile recorded at -1% set-point showed the least number of points at which the voltage magnitudes reaches the upper maximum limits implying reduced curtailment frequency when compared with +3% and +1% set-points.

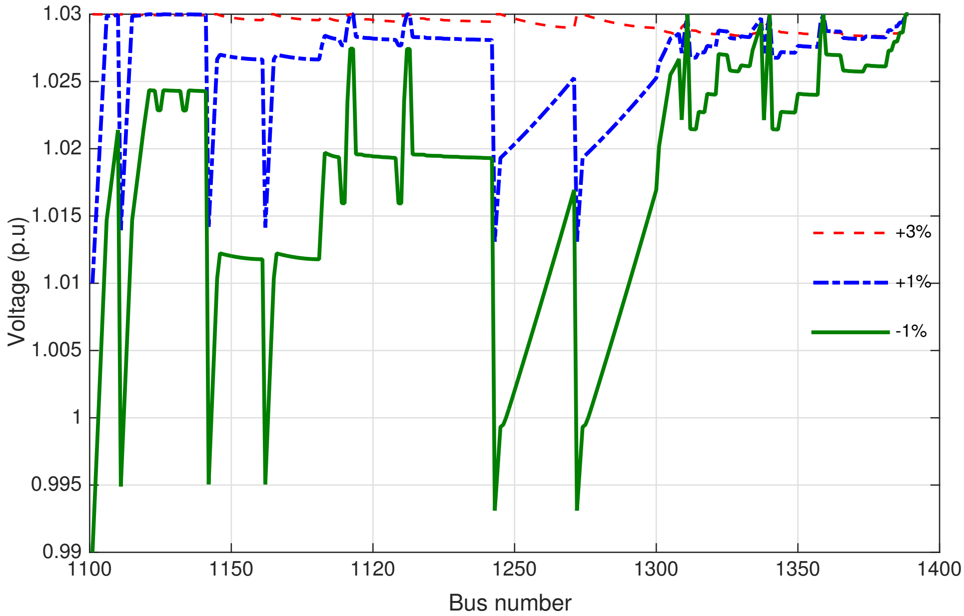


Figure 4.12: Maximum voltage profile

To compare the actions of the tap operation with respect to changes in set-point voltages, the tap positions are treated as continuous variables during the optimisation. A base-case is initially investigated where the OLTC transformer set-point voltage is modelled to vary between the full set of minimum and maximum operational limits $-3\% \leq V_s \leq +3\%$. The OPF simulation is run for a full month and Figure 4.13 presents result of the base-case scenario. The result presented shows high variation and changes in set-point voltages of the AVC relay which controls the OLTC indicating a potential increase in the number of tap operation of the transformer.

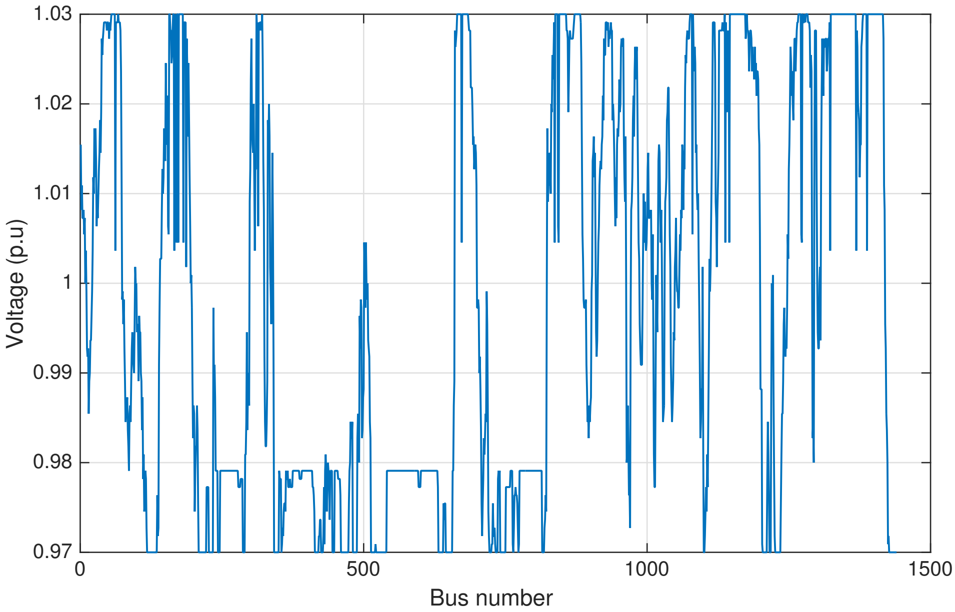


Figure 4.13: Changes in set-point voltage at full range

In this study, the optimised operating range for the OLTC transformer is established at $-1\% \leq V_s \leq 0\%$. The OPF simulation is run at the optimised operating range for a full month and Figure 4.14 shows a significant reduction of changes in voltage variation when the AVC is operated within the narrowed operating range. The result obtained at the end of the optimisation indicates a potential reduction in the number of tap changing operation of the OLTC transformer. This in the long-term will enhance the life-span of the transformer and reduce the cost of maintenance.

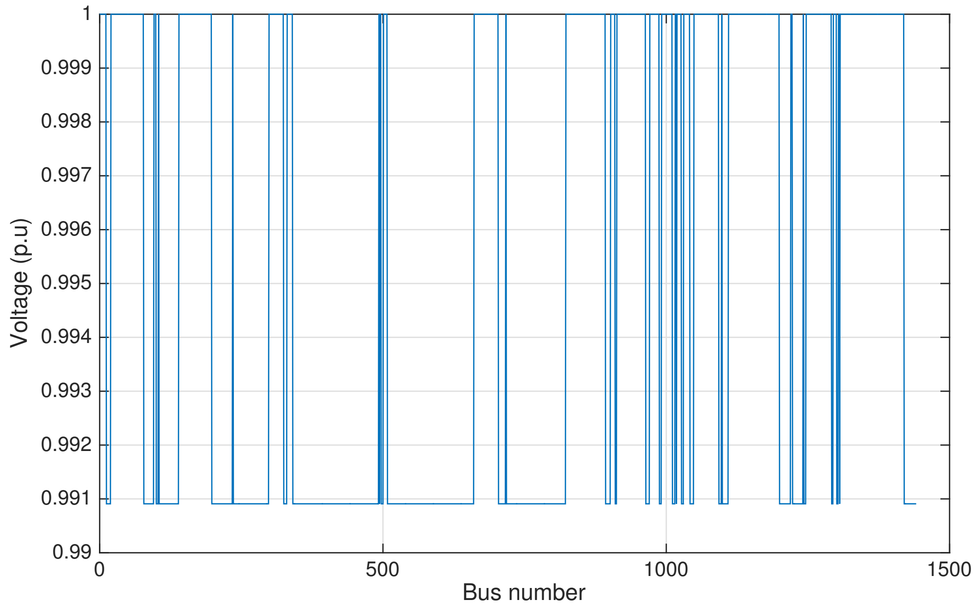


Figure 4.14: Changes in set-point voltage at optimised operating range

4.5 Summary

This chapter has presented voltage control techniques that utilises the existing network asset such as on-load trap changing (OLTC) transformers installed at the primary substation to control the network voltage and improve hosting capacity. The studies conducted in this chapter has implemented active network management (ANM) tools involving a coordination of on-load tap changer transformers and area-based active power curtailment techniques to control the voltages by testing on a representative UK distribution 11 kV network. The key case-study questions have been addressed by adopting a constraint optimisation technique that configures the set-point voltages of the OLTC transformer at the primary distribution substation. The study investigated an optimal set-point voltage control technique of the tap-changer transformer with an overall aim to improve network hosting capacity to accommodate greater wind connections at weak distribution networks.

The results obtained demonstrated that, configuring the AVC relays at lower set-point voltage significantly improves the network hosting capacity. By doing so, the DG voltage margins can be improved and the active power impact on the voltage rise constraint effectively minimised. The studies conducted in this chapter has demonstrated that, controlling the transformer within a narrowed optimum operating range effectively reduces the number of tap changing operations allowing for an improved life-span and reduced maintenance cost.

The paradigm shift towards an intelligent and advanced distribution management systems (DMS) requires sophisticated control strategies that optimises the existing network assets. Addressing the voltage rise problem efficiently will require a well-coordinated DMS that can control transformer tap changers, active generation, network loads and reactive power generation. The advent of ANM techniques is offering a feasible solution in this direction in developing an efficient, flexible, and reliable networks. In Chapter 5, ANM solution technique such as reactive power control capabilities of modern wind turbine technologies is explored as a mitigation tool to the voltage rise problem and it's potential to enhance DG generation capacities are investigated.

Chapter 5

DISTRIBUTION VOLTAGE CONTROL UTILISING THE REACTIVE POWER CAPABILITIES OF WIND GENERATORS

5.1 Introduction

A decentralised approach to distribution voltage control that fully utilises the reactive power capabilities of DWGs is an emerging technology and one that has not yet been investigated extensively. This chapter models the problem and provides the first study to an example of a second-generation ANM technological solution that employs greater participation from the wind generator connections to overcome the voltage constraint problem. This technique is novel and provides DNOs greater flexible to network voltage management whilst limiting grid imports of power, minimising dependencies on the transmission network.

It also provides wind farm developers an opportunity to correct and mitigate their impact on voltage rise constraint using their reactive power dispatch and power factor control capabilities whilst providing reactive power ancillary support to the network.

5.2 Variable speed wind turbine generator technology

The recently developed modern variable speed wind turbine generator has multiple control objectives. These includes; maximum power extraction from the wind, reactive power exchange with the grid, voltage regulation, low voltage ride through (LVRT) [74]. There are three main controllers within the variable speed wind turbine that provide controls for frequency/active power, voltage/reactive power and pitch angle/mechanical power [99]. This thesis however focuses on the voltage/reactive power aspects of the DFIG wind turbine generator.

Large variable speed wind generators are characterised by their low stresses on mechanical structures, reduced acoustic noise and ability to control both active and reactive power output using their power electronic interface with the grid [144]. They are cost effective and have the ability to comply with grid connection requirements. The reduced mechanical load performance are made possible by their ability to operate in variable speed mode. Their operational design principles incorporates a pitch control mechanism that limits maximum power output at high wind speeds and a fixed pitch angle at lower wind speeds [145]. The generator topology includes either a doubly fed induction generator (DFIG) system or the fully rated converter (FRC) based system. The DFIG technology is currently the most widely adopted among wind turbine manufacturers for larger wind turbines and is at the moment the predominant technology in most onshore wind farm development [146].

5.2.1 Doubly fed induction generator (DFIG) wind turbine

A simple configuration of a DFIG wind turbine generator is shown schematically in Figure 5.1. The design architecture utilises a wound rotor induction generator with slip rings to transmit current in or out of the rotor winding [144].

The generator stator in this arrangement is directly connected to the grid. The variable speed operation mechanism is achieved by injecting a controllable voltage into the rotor at slip frequency. The rotor winding is fed through a variable frequency power converter, typically based on two AC/DC insulated-gate bipolar transistor (IGBT)-based voltage source converters (VSCs), linked by a DC bus. Variable speed operation of the wind turbine is achieved by decoupling the grid frequency from the rotor mechanical frequency using the power electronic converters. The generator and converters are protected by voltage limits and an over-current crowbar [75].

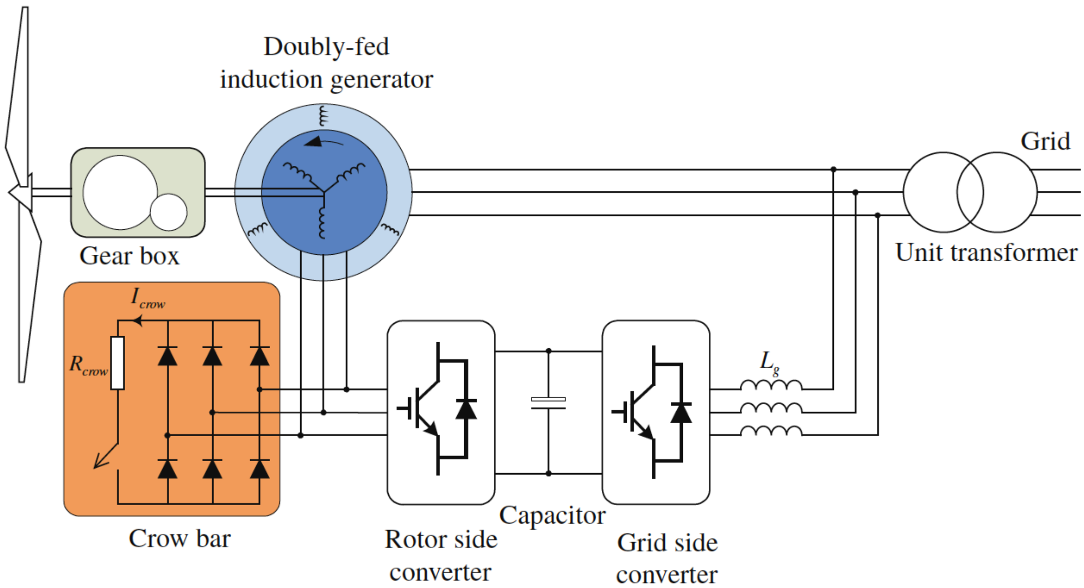


Figure 5.1: Simple configuration of a DFIG wind turbine generator [99]

The control of the DFIG wind turbine is achieved through the power electronic converters which consists of a rotor side convertor and a grid side convertor [75]. The rotor side converter to is used to provide torque-speed control, together with terminal voltage or power factor (PF) control for the overall system. The rotor side convertor directly controls the active and reactive power flows from the stator of the DFIG turbine to the network. This is made possible by controlling the magnitude, frequency and phase angles of the three-phase currents injected into the rotor by the duty ratio (Pulse Width Modulation) control of the voltage source convertor [99]. The rotor side convertor also enables voltage regulation at the generator terminal voltage by controlling reactive power (decoupled from active power control) exchange between the induction generator and the grid. In most recent operations, the rotor side convertor can be used to supplement control to provide frequency support to the grid by changing active power transfer during large disturbances using inertia of the wind turbine [99].

The grid side convertor is used to regulate and maintain the DC-link voltage and provide a path for rotor power flow to and from the rotor side convertor and the grid at unity power factor. The grid side convertor provides additional reactive power support to the network similar to the operation of a STATCOM within the constraints of the generator MVA ratings, which are usually lower than the wind turbine ratings [75].

5.2.2 Voltage and reactive power control of a DFIG wind turbine

Most DFIG wind turbine generators have the capability to provide reactive power support to the grid through the stator by changing the rotor excitation current [147]. The configuration of the DFIG turbine is shown in Figure 5.2 along with schematic of the power converters used are presented for illustrative purpose.

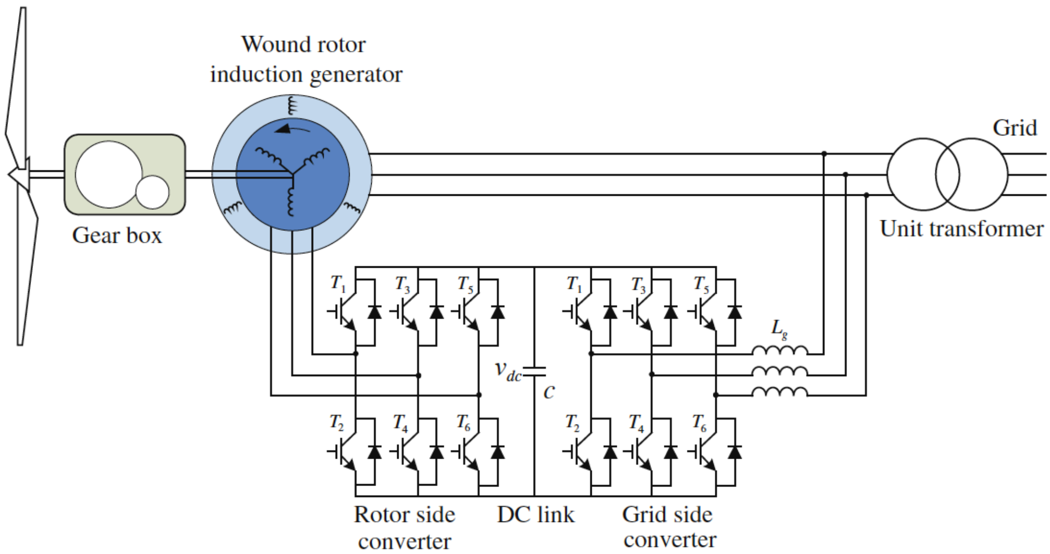
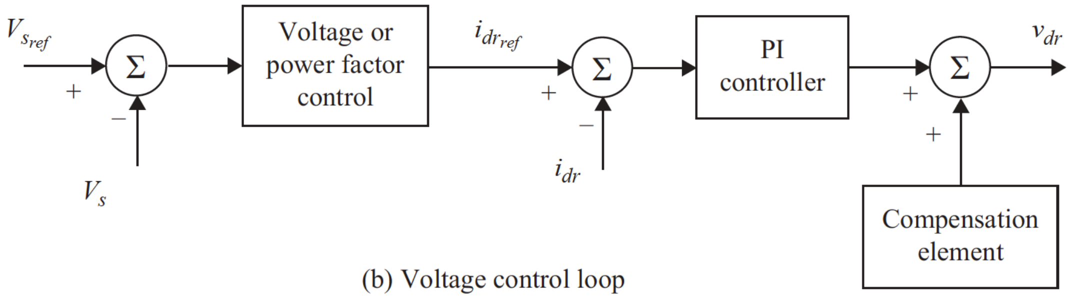


Figure 5.2: Configuration of a DFIG system with power convertors [99]

The generator is equipped with two back-to-back, three-phase, voltage source converters that shares a common DC link. The rotor side VSC injects controlled, variable frequency (slip frequency) currents into the rotor of the DFIG through the slip rings. The grid side converter interfaces with the three-phase grid and supports power exchange between the rotor of the DFIG and the grid through the DC link. The grid side converter operates to provide reactive power support within the rated limits [145].

The preferred method for representing a DFIG turbine is in terms of direct and quadrature (dq) axes, and it serves as a reference frame that rotates at synchronous speed. Adjusting the dq-axes components of the rotor provides the capability of independent control over the two generator variables. Each of these components can be controlled separately. The current-mode control methodology is commonly used where the d-axis component of the rotor current is used to control terminal voltage which control reactive power flow, and the q-axis component is used to control the generator torque which controls active power flow. [75].

A basic implementation of the DFIG voltage control/power factor control is shown schematically in Figure 5.3. In this arrangement the difference in magnitude between the terminal reference voltage ($V_{s_{ref}}$) and the actual terminal voltage (V_s) is manipulated to generate the rotor reference current in the d-axis ($i_{dr_{ref}}$) frame. The reference current ($i_{dr_{ref}}$) is then compared with the actual value of the rotor current in the d-axis (i_{dr}) frame to generate an error signal, to be processed by a standard PI controller. The required rotor voltage (v_{dr}) is obtained as the addition of the PI controller output and a compensation term used to eliminate cross coupling between torque and voltage control loops.



(b) Voltage control loop

Figure 5.3: Basic implementation of a DFIG voltage/power factor control [75]

An alternative approach to provide reactive power is through the use of a four-quadrant voltage source converter design at the grid side converter [99], which would then act as STATCOM and supply or absorb reactive power as needed at the POC. This device could function irrespective of whether the actual wind turbine generator was operational or disconnected from the system.

5.2.3 Proposed voltage control (VC) power factor control (PFC)/reactive power dispatch (RPD) control strategy

The proposed strategy is a flexible ANM solution combines the actions of optimised set-point voltage control technique of the OLTC transformer at the distribution primary substation, reactive power capabilities of the wind generators (PFC, VC/RPD modes) and active power curtailment techniques. The proposed strategy is formulated as an optimisation and problem and utilises mathematical ACOPF analysis techniques as seen in previous chapters.

Centralised voltage control at the distribution network involves configuring and lowering the set-point voltage at the 33/11 kV primary substation and holding it fixed at 10.89 kV (0.99 p.u) in the optimisation modelling. In this configuration, the OLTC transformer controls the secondary nominal voltages at the optimised reference set-point voltage. The technique enhances the network's hosting capacity to accommodate greater DG penetration levels as well as improving generation voltage margins to maximise power output.

Local area-based voltage control techniques engages the wind turbine generators to utilise their reactive power capabilities within the reactive power control modes (as seen in Figure 2.17) to mitigate the voltage rise issue at the POC with the distribution network. Here, depending on the voltage conditions at the various wind farm locations, the OPF engine initially off-sets the PFC mode. In this configuration, the wind farms reactive power output (Q) follows variation of active generation (P) to maintain a constant P/Q relationship. This mode of operation is aimed to maintain a specific power factor (PF) value as well as terminal voltage limits set by the operator at the point of connection. If this strategy fails to maintain the DG terminal voltages, the OPF engine switches to the VC/RPD mode where it optimally chooses both active and reactive generation values (within the rated limits) that maintains the voltage limits at the POC. The multi-period OPF engine studies the interactions between the multiple wind farm connections at the various geographical locations on the network. The OPF optimally switches between the three control modes based on the voltage conditions at any given time-step.

The third ANM technology utilises active power curtailment techniques where the OPF assesses available online capacity and optimally allocates capacities according to the wind farm's impact on the voltage constraint. The technique is implemented via a Technical Best principles of access arrangement.

5.3 Implementing reactive power control capabilities of modern wind turbines on a case-study network

This section explores the potentials of modern wind turbine technologies as a corrective device to the voltage rise problem at weak distribution networks. The study investigates the potential to mitigate the voltage rise limitation by exploring the reactive power capabilities of the wind farms. Modern DFIG wind turbine technology can control their terminal voltages within required limits through their power electronic interface with the grid. This section presents a flexible ANM solution for wind farm developers to overcome the voltage rise limitation to maximise their power output.

It also offers DNOs an alternative solution to network constraint management, differing or avoiding the need for costly and time-consuming network reinforcement.

The proposed reactive power capability technique of the wind turbine generators effectively utilises the operation of other ANM technological solutions including optimised operation of OLTC transformer at the HV/MV primary substation and active power curtailment techniques to control the network voltage within required limits. It evaluates the effectiveness of the strategy by testing on a representative UK generic 11 kV distribution network using time-series AC optimal power flow (OPF) simulations to quantify the benefit to the generators. The study investigates the power factor control (PFC) and voltage control (VC) modes of operation of multiple wind farm connections taking into accounts, the inherent stochastic nature of their power outputs. It proposes practical control solutions that mitigates the voltage rise issue effectively.

5.3.1 Key case-study question

The case study explores the potentials of modern variable speed wind turbine technology to effectively mitigate the voltage rise limitation through their reactive power capabilities. The proposed voltage control strategy utilises a multiperiod optimal power flow technique and implements it on the case study network to answer the key question:

1. How can we explore the potentials of modern variable speed wind turbines to participate in voltage control requirements on the distribution network?

5.3.2 Network description

As previously described in Chapter 3, the operation of voltage control utilising the reactive power capabilities of modern wind turbines is applied to the same test network (UKGDS) [HV UG-OHb] [118]. A technical best (TB) arrangement is adopted and implemented as the principle of access rule for connecting the multiple distributed wind generators and sharing curtailment. The model is deployed in Matpower [122] and time-series simulations are performed over a month period at half-hourly resolution, consisting a total of 1440 time-steps.

5.3.3 Mathematical formulation

Previous work reported by the authors in [148] involved a decentralised voltage control (VC) technique that modelled a single DG unit connection to mitigate the voltage rise problem. The study modelled the constant power factor control (PFC) and reactive power control (RPC) modes of operation. A similar PFC and VC methods have been studied in [149], where the authors employed a deterministic system that uses intelligent switching between the two modes. The authors target was to develop novel VC methods that could keep the DGs online during light or heavy demand conditions by combining the advantages of both voltage and power factor controls. The method was termed automatic voltage control power factor control (AVC/PFC). The steady-state response of the model was the generators ability to relax their power factors (PFs) when the bus voltages approached the statutory limits.

In the PFC mode of operation, the objective is to maintain and keep the P/Q relationship constant, with the reactive power output following variation of real power outputs [48]. In VC mode, reactive power is injected or absorbed to compensate for voltage variation at the point of DG connection. This mode of operation can potentially help maintain the voltages within desired limits. In [48], the authors compare both intelligent distributed and centralised VC techniques using OPF tools at a rural network set-up. A simple distributed reactive control approach for voltage rise mitigation at distribution networks have been proposed by Carvalho *et al* [150]. The authors implemented a reactive power control approach to mitigate the voltage rise caused by active power injections.

While both VC and PFC techniques are well established, their combination at multiple wind farm connection arrangement has never been co-ordinated actively to address the voltage rise problem at weak distribution networks. In this case-study, the proposed voltage control strategy is formulated as an optimisation problem that makes use of mathematical ACOPF algorithms using time-series simulations. It utilises the standard ACOPF [123, 124] formulation at each time-step and models multiple wind farm connection arrangements operating at either constant power factor (CPF) or variable power factor (VPF) control modes. The proposed scheme combines the advantages of VC/RPD-PFC control modes to address the voltage rise problem. The optimisation aims to achieve the following system objectives:

1. Maximise wind generation output at a minimum cost
2. Minimise the impact of the wind farms on the voltage profiles
3. Minimise transmission grid supply or import of power onto the distribution network

The ACOPF based problem is modelled as a set of non-linear equations consisting equality and inequality constraints and are outlined as follows:

$$Optimise : f(x) \tag{5.1}$$

subject to

$$g(x) = 0 \tag{5.2}$$

$$h(x) \leq 0 \tag{5.3}$$

where; f represents the objective function, g represents the physics of the power system enforced through the power flow equations, h represents the parameter limits of the system. x represents the optimisation vector consisting of bus voltages V_i, voltage angles θ_i, generator real power P_{Gi}, generator reactive power Q_{Gi} and is shown as:

$$x = \left[\theta_i \; V_i \; P_{Gi} \; Q_{Gi}\right] \tag{5.4}$$

The objective to maximise wind power generation output at minimum cost consist a summation of individual quadratic cost terms of each generator unit i real power f_{pi} and reactive power f_{Qi} injections and can be expressed as:

$$min \sum_{i=1}^{N_G} P_{Gi} + Q_{Gi} \tag{5.5}$$

In this study, the OPF model assigns high cost values to the swing bus to discourage grid power imports from the transmission network at the GSP and low cost values to all wind farms to encourage active and reactive demands on the network be met by the wind farms. To allow non-bias of the difference in generation costs, the OPF model assigns equal quadratic cost values to all the wind farm generators. This then allows the OPF engine to curtail the generators based on their output power impact on the constraint. Variables within the optimisation vector are constrained within a certain minimum and maximum bound and is described as:

$$x^{min} \leq x \leq x^{max} \tag{5.6}$$

The equality constraint in equation (5.2) refers to the full set of non-linear real and reactive power balance equations and is formulated as:

$$P_{Gi} - P_{Di} - \sum_{i=1}^{N_G} |V_i V_j Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) = 0 \tag{5.7}$$

$$Q_{Gi} - Q_{Di} + \sum_{i=1}^{N_G} |V_i V_j Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) = 0 \tag{5.8}$$

The inequality constraints defined in equation 5.3 represent the physical realities of the power system in equation and consists of bus voltage angles and magnitude limits, generator real and reactive power limits and branch flow thermal limits and is presented in equation 5.9 to equation 5.13.

- *Voltage limits*

$$\theta_i^{min} \leq \theta_i \leq \theta_i^{max} \tag{5.9}$$

$$V_i^{min} \leq V_i \leq V_i^{max} \tag{5.10}$$

- *Generation limits*

$$P_{Gi}^{min} \leq P_{Gi} \leq P_{Gi}^{max} \tag{5.11}$$

$$Q_{Gi}^{min} \leq Q_{Gi} \leq Q_{Gi}^{max} \tag{5.12}$$

- *Thermal limits*

$$|S_{ij}| \leq S_{ij}^{max} \tag{5.13}$$

Line thermal limits are relaxed in this configuration to allow the voltage operate as binding constraints to control the generators. To formulate the constant power factor (CPF) and variable power factor (VPF) control modes, some modifications are made to the ACOPF algorithm by introducing additional constraints to the generators in Matpower simulation environment [122]. The standard formulation is modified through additional cost function f_u and constraint variable z. This can be written in the following form:

$$f(x) + f_u(x.z) \tag{5.14}$$

subject to the equality and inequality constraints described earlier in equations (5.2), (5.3) and (5.6) as well as the inequality constraints described as:

$$l \leq A \begin{bmatrix} x \\ z \end{bmatrix} \leq u \tag{5.15}$$

$$z^{min} \leq z \leq z^{max} \tag{5.16}$$

where A refers to the user-defined sparse matrix, x is the optimisation vector described in equation (5.4), l and u represent the lower and upper bounds of the additional constraint respectively, in this case the generator reactive limits. In the case of CPF formulation, the generator units are constrained to a specific power factor (PF_i) plane, such that the P-Q capability curve is restricted and can only operate at either strictly inductive (VAr export) or capacitive (VAr import) mode. This condition is formulated into the ACOPF algorithm and takes the general linear constraint equation described as:

$$(QP_{ratio} \times P_{Gi}) - Q_{Gi} = 0 \tag{5.17}$$

where QP_{ratio} refers to the P/Q relationship of the generator units and is defined as:

$$QP_{ratio} = \sqrt{\left(\frac{1}{PF_i^2}\right) - 1} \tag{5.18}$$

given that;

$$PF_i = cos\phi_i = \frac{P_{Gi}}{S_i} \tag{5.19}$$

To estimate the generator's reactive power limits at each time-step, we can derive the following relationships:

$$Q_{Gi}^{max}(inductive) = \frac{P_{Gi}\sqrt{(1 - PF_i^2)}}{PF_i} \tag{5.20}$$

$$Q_{Gi}^{max}(capacitive) = -\frac{P_{Gi}\sqrt{(1 - PF_i^2)}}{PF_i} \tag{5.21}$$

In the case of VPF control strategy, the PF limits are relaxed and allowed to vary within a certain upper maximum and lower minimum bound to control the voltage and is described as:

$$PF_i^{min} \leq PF_i \leq PF_i^{max} \tag{5.22}$$

The additional non-linear inequality constraints are modelled into the ACOPF algorithm to define the lagging and leading PF boundaries of the generators and are formulated as:

$$0 < (QP_{ratio} \times P_{Gi}) - Q_{Gi} < \infty \tag{5.23}$$

$$0 < -(QP_{ratio} \times P_{Gi}) + Q_{Gi} < \infty \tag{5.24}$$

The generator reactive power limits are relaxed and freed to switch between inductive and capacitive modes within the specified P-Q capability limits shown as:

$$-Q_{Gi}^{min}(capacitive) \leq Q_{Gi}(optimum) \leq +Q_{Gi}^{max}(inductive) \tag{5.25}$$

where the optimum reactive power dispatched $Q_{Gi}(optimum)$ at any given time-step and network voltage conditions may be either positive values between zero to the maximum inductive limits $+Q_{Gi}^{max}(inductive)$ or negative values from zero to the minimum capacitive limits $-Q_{Gi}^{max}(capacitive)$. All variables and constraints are formulated before calling the ACOPF command.

To assess the adequacy and benefits of the proposed CVC strategy to mitigate the voltage rise problem, five scenarios have been investigated and are summarised in Table 5.1. A base-case scenario is initially presented with the DGs modelled to operate at unity PF, representing current passive approach to voltage control methods at distribution networks. The rest of the scenarios evaluates the effectiveness of the control modes to control reactive power power generation of the wind farms to mitigate the voltage rise problem.

Table 5.1: Summary of power factor and voltage control strategy

Scenario	Control strategy	PF
1	Base-case	unity
2	Constant PF	0.95 lag
3	Constant PF	0.95 lead
4	Variable PF	$0.98\ lead \leq PF \leq 0.95\ lag$
5	Variable PF	$0.95\ lead \leq PF \leq 0.95\ lag$

Here, all the DG units are assumed to have been awarded connection contracts with the DNO that allows them to participate in voltage control activities on the network. They are also assumed to be equipped with modern technological capabilities (DFIG topologies) through their power electronic interface with the network that makes them available to the ACOPF to support reactive demands. This is in the form of their ability to operate in either PFC or VC/RPD control modes to regulate reactive power generation and control voltage at the POC.

The model is implemented in Matpower [122] which uses interior point method (IPM) optimisation methods for the constrained nonlinear programming (CNLP) problem. Time-series simulation are performed over a full month period at half-hourly resolution and consists a total of 1440 time-steps. Each scenario provides a quantitative assessment of the benefit including energy yields and subsequent curtailment levels required to maintain the network limits

5.3.4 Case study results and discussion

In this section, the five scenarios investigated and corresponding simulation results (Appendix C) obtained are presented for analysis and discussion. The studies explores the potentials of modern variable speed wind turbine technology applications as corrective devices to the voltage rise problem at weak distribution networks. It evaluates the effectiveness of the proposed strategy by assessing connection capacities of the wind farms whilst providing grid ancillary reactive power support. It also quantifies active power curtailment levels required to maintain network operational constraints when the strategies are implemented.

The studies presented in this chapter offers an alternative, cost-effective and faster solutions to release additional capacity for distribution network planning and expansion. The voltage control strategy implemented in the case-study is a flexible ANM solution that utilises optimised set-point voltage control technique of the OLTC transformer at the primary substation, reactive power capabilities of the wind turbine generators (PFC, VC/RPD modes) and active power curtailment techniques implemented via a Technical Best PoA arrangement with objective to maximise wind energy levels. The investigated voltage control scenarios are benchmarked with current DNO practice (unity PF) to quantify the benefit and drawbacks to the wind farms. The total wind energy generation across the various scenarios are summarised graphically in Figure 5.4.

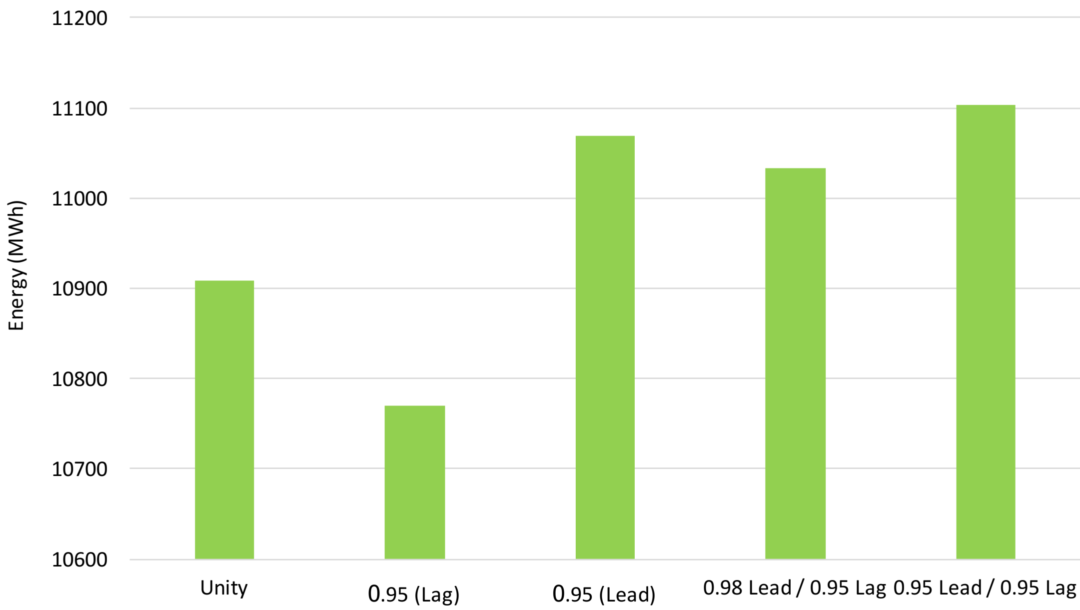


Figure 5.4: Total energy generation

Here, it is seen that operating the generators at CPF control 0.95 lag results in reduced energy yields by a total of 139 MWh when benchmarked with the base-case scenario (unity PF). Operating the wind farms in strictly inductive mode influences and amplifies the network voltage profiles, thereby forcing the OPF to reduce active generation to levels that maintains the constraint. On the contrary, this mode of operation provides greater benefit of reducing excessive VAr import from the transmission network as reactive demands on the network are predominantly met by the wind farms.

In the case of CPF control 0.95 lead, the total energy levels increased by 160 MWh when benchmarked with the base-case scenario (unity PF). However, wind turbine generators operating in strictly capacitive mode import a great deal of reactive power from the network to control their voltage at the point of connection without contributing to meeting reactive demands. This operation condition of the wind farms poses as negative loads on the network and may require some form of an agreement to be reached during the negotiation stage with the DNO to justify this mode of operation before connection offers are made.

By adopting a VPF control approach, the wind farms enhances their scope for greater voltage control capabilities and allows for a fair reactive power exchange with the network. In this configuration, the OPF engine assesses the voltage constraint at each time-step and selects an optimum control strategy (VC/RPD - PFC) that fulfils the objective functions including: minimising grid import of power (MVArs and MW), minimising the impact of the wind farms on the voltage profiles and maximising active power output. At 0.98 lead and 0.95 lag VPF mode, the energy levels are increased by a total of 124 MWh when benchmarked with the base-case scenario. In the case of operating the wind farms between 0.95 lead and 0.95 lag VPF mode, the results obtained showed the most benefit of greater energy yields with a total increase by 194 MWh when compared with the rest of the control strategies.

Allowing greater flexibility of the generator's P-Q capability limit can result in improved performance of the wind farms to effectively mitigate the voltage rise problem and maximise their power output. It can be observed that; adopting a VPF control mode with the wind farms modelled to operate between 0.95 lead and 0.95 lag results in greater energy yields and an improved network access for the remotely connected wind farms.

5.3.4.1 Scenario 1: Base-case (PF = unity)

In scenario 1 which represents the base-case condition, the wind farms are modelled to operate at unity PF. In this configuration, the reactive power output of the wind farms are set to zero and not allowed to participate in voltage control activities on the network. Centralised voltage control at the 33/11 kV primary substation is achieved by lowering the set-point voltage of the AVC relay that controls the OLTC transformer to -1% of the nominal voltage. Here, the OLTC transformer controls the rest of the secondary bus voltages at the optimised set-point voltage (0.99 pu). Local voltage rise conditions occurring at the point of interconnection are controlled by curtailing the active power output of the generators.

Available energy of the wind farms refers to the unconstrained generation, where's actual generation refers to the constrained generation. At the end of the ACOPF simulation, generator A, generator B and generator C located at the strong sections of the network are all observed to be operating up to their maximum installed capacities with minimum curtailment as seen in Appendix C1. The remotely connected wind farms such as; generator G and generator H are observed to be operating below 50% of their installed capacity and are observed to experience the most curtailment. The simulation results also reveals a total generation capacity of 84.9% across the DG units with 15.1% curtailment required to maintain the network constraint.

5.3.4.2 Scenario 2: Constant PF (PF = 0.95 lag)

In the case of constant power factor (CPF) control mode, the generator's PFs are constrained and can only operate at either strictly lagging or strictly leading control modes. Here, the OPF engine is modelled to implement a constant PFC mode of operation of the wind farms. In this arrangement, the reactive power output (Q) of the generators at any given time-step is optimally selected by the OPF engine to match active generations (P) to maintain a constant P/Q relationship and the specified power factor value. Scenario 2 studies the interactions between multiple wind farm connections where they are modelled to operate at 0.95 lagging PF. In this arrangement, the DGs are modelled to export VArs (inductive mode) to support reactive demands on the network within their rated active generation and reactive capability limits.

Centralised voltage control at the 33/11 kV primary substation is achieved by lowering the set-point voltage of the AVC relay that controls the OLTC transformer to -1% of the nominal voltage. Here, the OLTC transformer controls the rest of the secondary bus voltages at the optimised set-point voltage (0.99 pu). Voltage rise conditions occurring at the point of DG interconnections with the network are locally controlled by implementing the constant PFC mode and active power curtailment of the wind farm generators. At the end of the simulation, generator A, generator B and generator C are observed to be operating up to their maximum installed capacities as seen in Appendix C2. Conversely, generators G and generator H are observed to be operating below 50% of their installed capacities with power output marginally below the base-case scenario (Unity PF) configuration. The rest of the generators are also observed to be operating marginally below generation values obtained in the base-case scenario. Simulation results at the end of the ACOPF shows a total generation capacity of 83.8% with curtailment recorded at 16.2% to maintain the network operational limits.

5.3.4.3 Scenario 3: Constant PF (PF = 0.95 lead)

In this scenario, the multiple wind farm connections are modelled to operate at constant PFC mode, 0.95 leading PF configuration. In this arrangement, the wind farms are modelled to import VArs (capacitive mode) within their rated reactive power capability limits from the network to control their voltage at the POC. Centralised voltage control at the 33/11 kV primary substation is achieved by lowering the set-point voltage of the AVC relay that controls the OLTC transformer to -1% of the nominal voltage. Here, the OLTC transformer controls the rest of the secondary bus voltages at the optimised set-point voltage (0.99 pu).Local area voltage rise conditions occurring at the various wind farm locations are controlled by initiating the PFC mode and curtailing active power generation.

At the end of the simulation (Appendix C3), generators A, generator B and generator C are all observed to be generating up to their maximum installed capacities with minimum curtailment. Generator H is now observed to be operating above 50% of installed capacity. The rest of the generators are also observed to be generating above power outputs obtained during the base-case scenario (Unity PF). The ACOPF also reveals a total generation capacity of 86.1% across the DGs with total curtailment levels recorded at 13.9% to maintain the constraint.

5.3.4.4 Scenario 4: Variable PF (0.98 $lead \leq PF \leq$ 0.95 lag)

In the case of variable power factor (VPF) control mode, the OPF allows the wind farms to actively adjust their PFs within the specified PF limits by allowing optimum reactive power exchange between the network and the wind farms. In this configuration, the wind farms can import (lead) and export (lag) reactive power within the rated P-Q capability limits. Here, the OPF engine is modelled to implement intelligent switching between VC/RPD - PFC modes of operations to control the reactive power exchange based on the voltage requirements at the POCs. With overall system objective to maximise active generation output of the wind farms, the OPF optimally selects a suitable control mode (VC/RPD - PFC) that maximises the objective function at any given time-step.

Scenario 4 studies the behaviour of the wind farms when modelled to operate at PFs varying between 0.98 leading and 0.95 lagging (summary of results shown in Appendix C4). Centralised voltage control at the 33/11 kV primary substation is achieved by lowering the set-point voltage of the AVC relay that controls the OLTC transformer to -1% of the nominal voltage. Here, the OLTC transformer controls the rest of the secondary bus voltages at the optimised set-point voltage (0.99 pu). Local voltage rise conditions occurring at the multiple wind farm locations at any given time-step are controlled by employing intelligent switching between VC/RPD - PFC operational modes in conjunction with active power curtailment to mitigate the problem. At the end of the ACOPF simulation it is observed that, generators A, generator B and generator C are generating up to the maximum installed capacity with minimum curtailment. When benchmarked with the base-case scenario, this configuration is seen to enhance connection capacities for the wind farms by allowing reactive power exchange with the network. The results obtained also shows a total generation capacity of 85.9% and curtailment of 14.1% required to maintain the network constraint limits.

5.3.4.5 Scenario 5: Variable PF ($0.95\ lead \leq PF \leq 0.95\ lag$)

This scenario studies VPF control mode with the generators PFs modelled to operate between 0.95 leading and 0.95 lagging (summary of results shown in Appendix C5). Centralised voltage control at the 33/11 kV primary substation is achieved by lowering the set-point voltage of the AVC relay that controls the OLTC transformer to -1% of the nominal voltage. Here, the OLTC transformer controls the rest of the secondary bus voltages at the optimised set-point voltage (0.99 pu). Local voltage rise conditions occurring at the multiple wind farm locations at any given time-step are controlled by employing intelligent switching between VC/RPD - PFC operational modes to mitigate the problem. By further relaxing the power factor constraint limits it can be seen that, there is an improved access of the wind farms to the constrained network when compared with the rest of the scenarios investigated. Also in this arrangement, there is a fair amount of reactive power exchange with the network allowing the wind farms to regulate their terminal voltages at the point of interconnection whilst providing ancillary reactive power support to the network. Corresponding results at the end of the ACOPF reveals a total generation capacity of 86.4% and curtailment recorded at 13.6%.

Figure 5.5 presents a comparison of the maximum voltage profiles recorded across the network at single time-step measurements during the optimisation. Here, it is seen that operating the wind farms at VPF mode between 0.95 lead and 0.95 lag effectively mitigates the voltage rise problem. Variable PF (0.95 lead/lag) mode is observed with the minimum number of points at which the voltage profile reaches the upper maximum limit implying reduced frequency in wind curtailment levels.

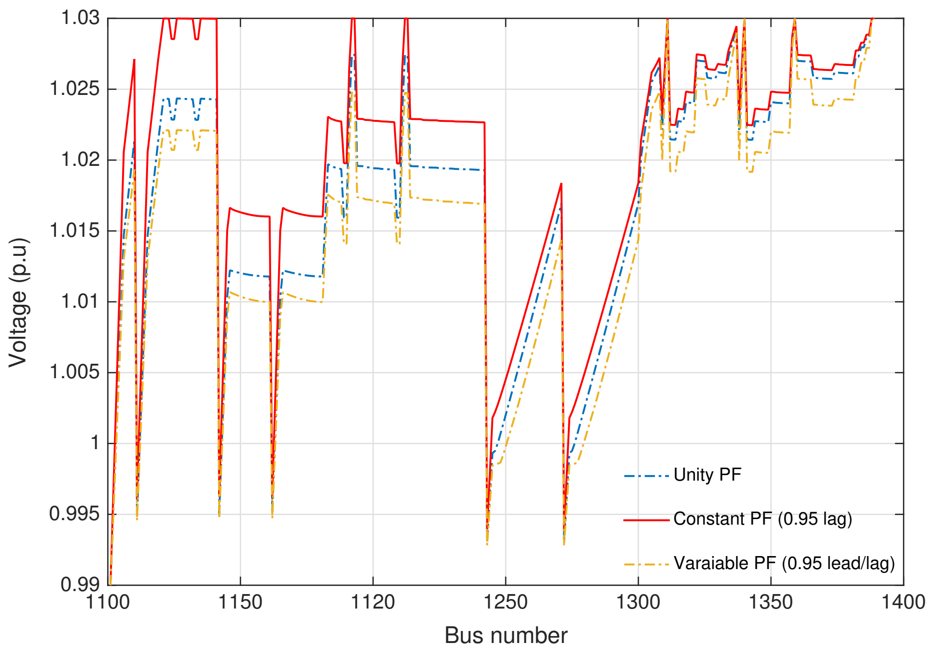


Figure 5.5: Maximum voltage profile

5.4 Summary

This chapter has presented a decentralised active network management (ANM) solution that utilises the reactive power capabilities of modern wind turbine technology at distribution networks. The chapter have explored the integration of variable speed wind turbine technology as corrective devices to the voltage rise limitation problem at weak distribution networks. The modern DFIG topology have been identified as a potential technology to mitigate the voltage rise issue through their power electronic interface with the grid.

To evaluate the effectiveness of the proposed voltage control strategy, a detailed case-study assessment that fully utilises the reactive power capabilities of the wind turbines have been presented. The key case-study question have been addressed by modelling the control modes of multiple wind farm connections for reactive power generation using optimal power (OPF) optimisation techniques. The proposed technique effectively utilises the operation of other ANM technological solutions involving optimised operation of the OLTC transformer at the HV/MV primary substation and active power curtailment techniques to control the network voltages within required limit. The reactive power control modes investigated included; voltage control (VC), power factor control (PFC) and reactive power dispatch (RPD) modes. The study investigated a number of operational scenarios where the power factors of the multiple wind farm connections can be manipulated to quantify the benefit to the wind wind farms. These included implementing conditions where the wind farms operated at constant power factor (CPF) and variable power factors (VPF) modes. The study evaluates the effectiveness of the proposed strategy by assessing wind farms connection capacities whilst providing grid ancillary reactive support and the curtailment levels required to maintain the constraint.

Chapter 6

COORDINATED VOLTAGE CONTROL AND PRINCIPLES OF ACCESS TECHNIQUES FOR DISTRIBUTED WIND GENERATORS

6.1 Introduction

This chapter presents novel voltage control techniques involving a coordination of ANM solutions and principles of access (PoA) arrangements specific for wind farm connections at weak distribution networks. The proposed coordinated voltage control (CVC) strategy and PoA effectively mitigate the voltage rise limitation with aim of maximising wind farm connection capacities. The proposed CVC involves a coordination of optimised operation of OLTC transformers, reactive power dispatch capabilities of the wind turbines and active curtailment of the generators to mitigate the voltage rise problem. It implements PoA techniques previously discussed in Chapter 3 as a tool to share curtailment in conjunction with the CVC techniques to maximise wind generation levels. It assesses such potentials using a representative UK generic 11 kV distribution network. It undertakes an extensive study over a full year to quantify the benefit and impact to the wind farms. This section presented is important as it shows that the theory presented throughout the thesis can provide real insight into both current and future ANM projects.

6.2 Proposed voltage control strategy

The proposed solution displayed in Figure 6.1 develops a coordinated voltage control (CVC) strategy and PoA techniques that aim to mitigate the voltage rise problem. It relates to the work presented in the previous chapters and adopts a hierarchical and systematic approach to implementing the control actions with the aim of maximising wind farm connection capacities at weak distribution networks. This strategy leverages previous passive approach to distribution voltage management and introduces a coordination of current ANM technological solutions and PoA arrangement specific for voltage constrained active networks. The previous passive solution includes the Fit and Forget approach where there was minimum or no control and monitoring of the distribution network. The proposed strategy in this chapter attempts to maximise DG connection capacities at a minimum cost and provides DNO's and wind farm owners, flexible control options that defers or avoids capital intensive network upgrades.

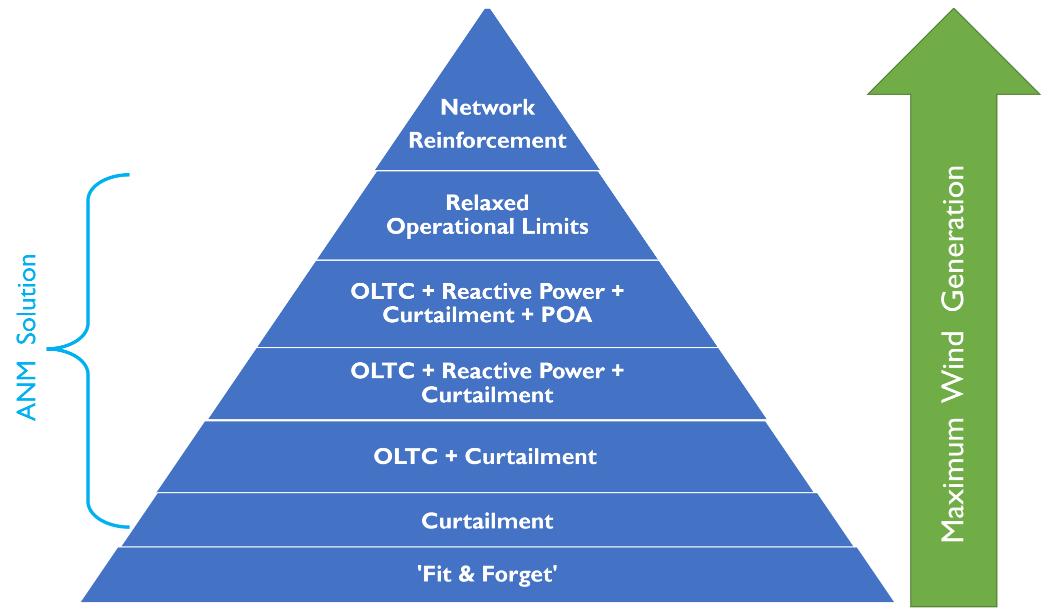


Figure 6.1: Proposed voltage control strategy

The hierarchical approach and the order at which the ANM control actions are implemented are defined by the desire to increase wind energy levels in a timely and cost-effective manner. As we move up the proposed triangle, we move up in sophistication in fulfilling our key objective of accelerating renewable wind farm connections. The proposed strategy is specific to the case-study network presented in this thesis and the outcome provides a guide on how the methods could be implemented to manage future distribution networks. The strategy presented is flexible and the order at which the control actions are implemented can be customised for different network applications. The proposed flexible options will equip DNOs with the appropriate tools to apply the different techniques to different network configurations and objectives in order to unlock additional network capacity to facilitate greater, cheaper and faster wind farm connections.

For instance, a DNO may choose to directly reinforce their network to release additional hosting capacity and avoid implementing the whole range of the ANM control solutions. Another may choose to implement a relaxed network constraint approach and may deem it as an optimised solution that enhances their network.

In another case, a DNO may choose to offer the suit of the proposed solutions to existing or new generators wishing to connect, providing greater flexibility to network management and as a way to attract more wind farm investment. Each of these techniques offer their own benefits and drawbacks and are usually driven by the DNO's operation and planning objectives, existing network assets, cost and regulatory requirements. In all cases, an extensive desk study should be undertaken to assess the cost and benefit of investing in ANM technologies to fulfilling the planing objectives and can be compared with the cost associated with reinforcing the network. The cost benefit analysis will help inform DNOs and provide a guide for wind farm owners and other stakeholders during their decision making process.

Recent ANM technologies embedded in distribution networks are providing alternative, faster and cost-effective solutions to network planning and expansion. With recent increase in DG penetration, ANM requirements and specifications has been developed to clearly identify the key functionalities of the technology and what attributes a user may require the functionality to possess. In essence, these requirements show what an ANM system must conform to and the behaviour of its operation. In this respect the ANM scheme must be:

- Safe - it must operate in a safe manner to ensure the safety of personnel and not subject network operations to adverse control decisions.
- Secure and available - the use of available communications channels will be secure and ensure the ANM scheme is not compromised.
- Flexible and extensible - the flexible nature will ensure that the scheme is easily reconfigurable for future network changes. As such the core functionality remains the same with only the inputs for the control decision making elements having to be updated. Network events that would entail such revisions are:
  - changes in network topology and architecture,
  - plant renewal (changes in equipment rating),
  - addition or removal of DG units

- inclusion or removal of further controllable devices e.g. energy storage systems
- changes in contractual arrangements

6.3 Base-case model

A base-case test network is set initially as a benchmark to assess the effectiveness of the proposed voltage control strategy for active distribution networks. It provides a basis to compare, validate and evaluate the robustness of the proposed strategy when applied under certain likely changes in future network operation conditions. An extensive study is performed on the base-model for a full one-year to provide a comprehensive assessment of the strategy when implemented at weak distribution networks. It quantifies the economic benefit in terms of renewable energy yields and provides an indication of prospective revenues for DG investments at the various sections of the network. The base-case model utilises a similar model developed earlier in Chapter 3. A full one-year study is undertaken on the network and consists of half hourly time-series with a total of 17520 time-steps. One year generation and demand profiles used as input data to the optimisation modelling are presented in Appendix A.

6.3.1 Coordinated voltage control (CVC)

This section presents results of the non-firm wind generators controlled by ANM solution involving the application and combination of elements within the proposed coordinated voltage control (CVC) strategy for voltage rise mitigation in active distribution networks. It demonstrates the benefits on wind generation capacities and the economic viability of the non-firm generators when the CVC strategies are implemented. It presents a detailed assessment and impact on DG capacities in terms of wind energy generation and curtailment levels using an extensive time-series AC optimal power flow (OPF) simulations over a full year. This study assumes an unconstrained capacity factor (C.F) of 30% for the wind farms and the table of results are shown in Appendix D.

6.3.1.1 Curtailment

In Chapter 3, curtailment is defined as any limitation that prevents a DG exporting its maximum capacity to the distribution or transmission network [109] and can also be referred to as the reduction in generation output to an output level lower than available [60]. Curtailment practice in distribution networks is one among many tools of recent ANM techniques to facilitate quicker and cheaper DG connections [101]. It has become useful in distribution management systems to maintain energy balance including grid capacity, demand response and storage.

The network configuration in this voltage control application is modelled such that, the set-point voltage at the primary substation equipped with the two identical 33/11 kV OLTC transformers (each rated at 22 MVA) is operated at current DNO practice for voltage control. This implies configuring the AVC relay set-point voltage and holding it fixed at 1.02 p.u (11.22 kV) during the optimisation. The secondary bus voltages are also constrained at current DNO operational limit and allowed to vary within a permissible range of ±3% of the nominal. Here, the wind generators are modelled and connected to the network as PQ nodes and assumed to operate at unity power factor with no voltage control capabilities. Voltage control on the network is primarily achieved by curtailing the generation output with no interventions from the network operator or the generators. The sharing of curtailment among the non-firm wind farm generators is via a technical best arrangement. In this arrangement, all the DGs have equal priority access to the network and the limited network capacity is optimally shared according to the DG's impact on the constraint.

With optimisation objectives set to maximise wind generation output whilst controlling network voltages, the summary of results are shown graphically in Figure 6.2. The time-series OPF simulation results reveal a total non-firm generation of 103.89 GWh corresponding to 58% energy generation out of 179.39 GWh available energy, yielding a total capacity factor of 17.4%. The total curtailment experienced by the DGs were recorded at 42%. The generator performance results shown in Figure 6.2 reveal greater connection capacity for the electrically closest generators to the primary substation due to their strong location on the network.

Here, the OPF engine optimally allocates generation capacities according to the wind farm's impact on the voltage rise constraint. As a result, generators with minimum impact on the constraint are highly favoured over ones with significant impact on the constraint. Conversely, it is seen that greater curtailment are allocated to generators further away from the primary substation due to their weak location on the network. The capacity factor (C.F) for the generators is seen to decrease steadily as we move further away from the primary substation.

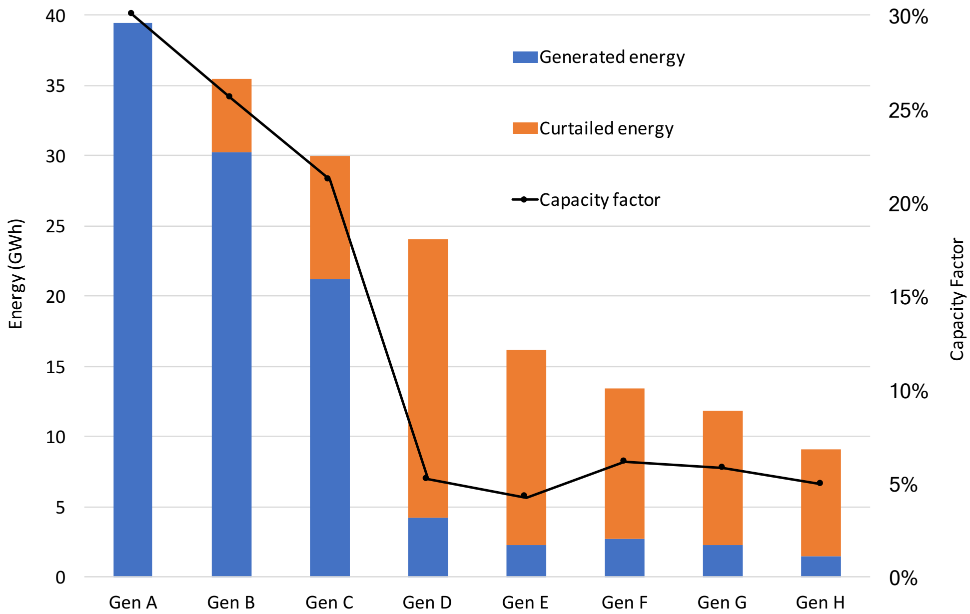


Figure 6.2: Generator performance (Curtailment)

6.3.1.2 On-load tap changer transformer (OLTC) + Curtailment

In Chapter 4, an investigation of an optimum set-point voltage control technique of the 33/11 kV OLTC transformer at the primary substation was undertaken with aim to improve network hosting capacity to accommodate high wind penetration levels. A coordinated ANM solution involving the OLTC transformer operations and area-based active generation curtailment was implemented to control the network voltages. The voltage control option utilised the distribution network asset such as, on-load tap changing transformer operations to improve DG voltage margins.

This study follows a similar configuration of the network's OLTC transformer set-point voltage technique discussed in Chapter 4. The network configuration in this voltage control option is modelled such that, the voltage set-point of the 33/11 kV OLTC transformer is lowered and held fixed at the optimum value (discussed in Chapter 4) of 0.99 p.u serving as reference voltage for the rest of the secondary substations. Voltage control is achieved by centralised control measures of improving DG voltage margins at the primary substation in coordination with area-based active power curtailment of the wind farms at their point of connection with the network. The sharing of curtailment among the non-firm wind farm generators is via a technical best arrangement. In this arrangement, all the DGs have equal priority access to the network and the limited network capacity is optimally shared according the DG's impact on the constraint.

At the end of the OPF simulation, the results reveal a total non-firm generation of 135.06 GWh corresponding to 75% energy generation out of 179.39 GWh available energy, yielding a total capacity factor of 23%. The total curtailment experienced by the DGs were recorded at 25%. In comparison with the first voltage control option (curtailment only), there's an improvement in total wind energy levels with the results showing an improved access for the remotely connected wind farms. Figure 6.3 reveal an improved generation capacity for all the wind farms due to improved voltage margins for the DG's. This was achieved by adjustment made by lowering the set-point voltage of the automatic voltage controller (AVC) that controls the 33/11 kV OLTC transformer at the primary substation. From here it can be seen that, wind farms located at the strong sections of the network are highly favoured over those located at the weak sections of the network. This is due to the fact that the OPF engine optimally curtails the generators according to their impact on the constraint. Hence it can be observed that, greater connection capacities are allocated to the electrically closest generators to the primary substation due to their minimum impact on the constraint and reduced losses. Conversely, greater curtailment are allocated to generators further away from the primary substation due to their significant impact on the constraint and contributions to network losses. The capacity factor (C.F) for the generators decreases steadily as we move further away from the primary substation.

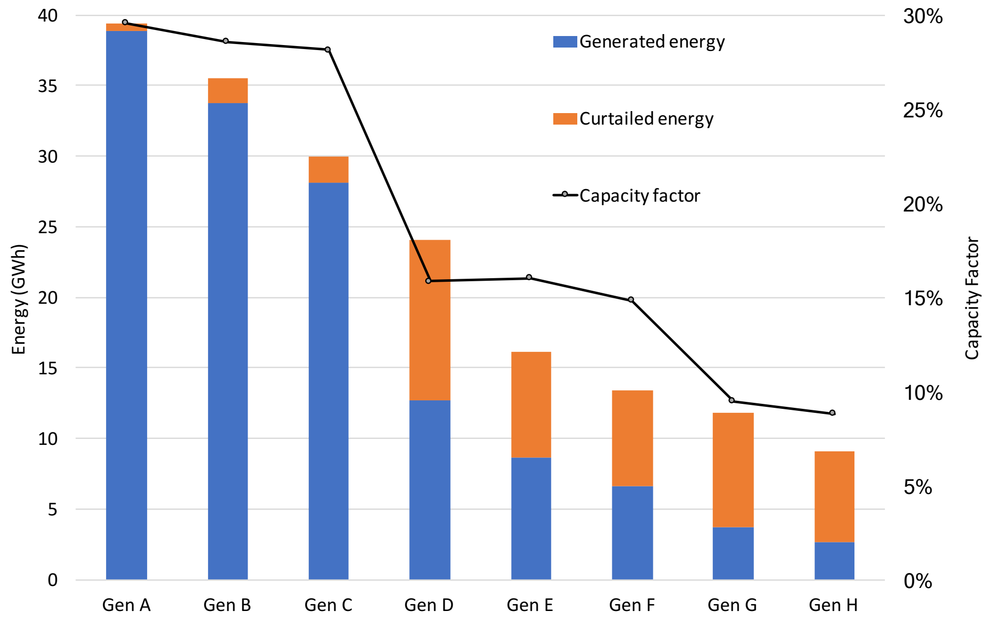


Figure 6.3: Generator performance (OLTC + Curtailment)

6.3.1.3 On-load tap changer transformer (OLTC) + Reactive Power + Curtailment

In Chapter 5, a decentralised approach to voltage management that fully utilises the reactive power capabilities of the wind farms was introduced as an ANM technique. The chapter explored the potentials of modern DFIG variable speed wind turbine integration in distribution networks to mitigate the voltage rise problem, maximise energy capture and provide reactive power support to the network. The scheme effectively coordinated the operation of other ANM solutions including optimised operation of the OLTC transformer at the HV/MV primary substation and active power curtailment techniques to control the network voltages within required limit. It combines the advantages of optimal switching between the reactive power control modes of variable speed wind turbine generators including, Voltage Control/Reactive Power Dispatch - Power Factor Control (VC/RPD-PFC) modes to address the voltage rise problem and to achieve the system objectives.

In this study, a similar configuration of the network discussed in Chapter 5 is adopted such that the voltage set-point of the 33/11 kV OLTC transformer is lowered and held fixed at the optimum value of 0.99 p.u serving as reference voltage for the rest of the secondary substations. The DFIG variable speed wind turbine generators are modelled to operate in variable power factor (VPF) mode such that, the power factors can vary between 0.95 leading and 0.95 lagging range to control the voltage and fulfil grid requirements at their POCs. Voltage control is achieved by a coordination of centralised and area based control measures. Centralised control includes lowering the set-point voltage of the AVC relay that controls the OLTC transformer at the HV/MV primary substation. Area based control includes configuring the reactive power capabilities of the wind turbine generators in combination with active power curtailment of the wind farms. In this arrangement, all the DGs have equal priority access to the network and the limited network capacity is optimally shared according the DG's impact on the constraint. The result obtained are presented graphically in Figure 6.4.

The time-series OPF simulation results reveal a total non-firm generation of 149.79 GWh corresponding to 83.5% energy generation out of 179.39 GWh available energy, yielding a total capacity factor of 25%. The total curtailment experienced by the DGs were recorded at 16.5%. In comparison with the first (curtailment only) and second (curtailment + OLTC) voltage control options, there's an increase in total wind energy levels with the results showing a much improved access for the remotely connected wind farms. The generator performance results reveals a much- improved performance in generation capacities when compared with the first two voltage control options studied. Here, by incorporating the reactive power capabilities of the wind farms effectively mitigates the voltage rise issues and enhances DG connection capacities. It can be observed that, generators with minimum impact on the constraint are highly favoured than generators with significant impact on the constraint. It is seen that, greater connection capacity are allocated to the electrically closest generators to the primary substation due to their strong location on the network. Conversely, greater curtailment are allocated to generators further away from the primary substation due to their weak location on the network. The capacity factor (C.F) for the generators decreases steadily as we move further away from the primary substation.

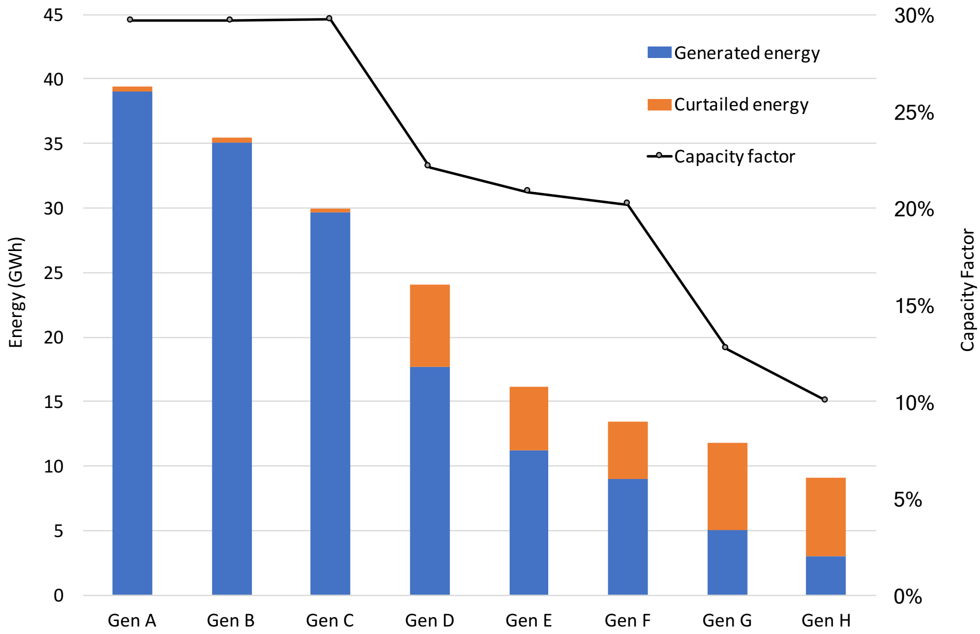


Figure 6.4: Generator performance (OLTC + Reactive Power + Curtailment)

6.3.2 Discussion of applied coordinated voltage control (CVC) techniques

Figure 6.5 presents a summary of the performance of the proposed coordinated voltage control (CVC) strategy when applied to a representative UK 11 kV distribution network with extensive simulations studies undertaken over a full year.

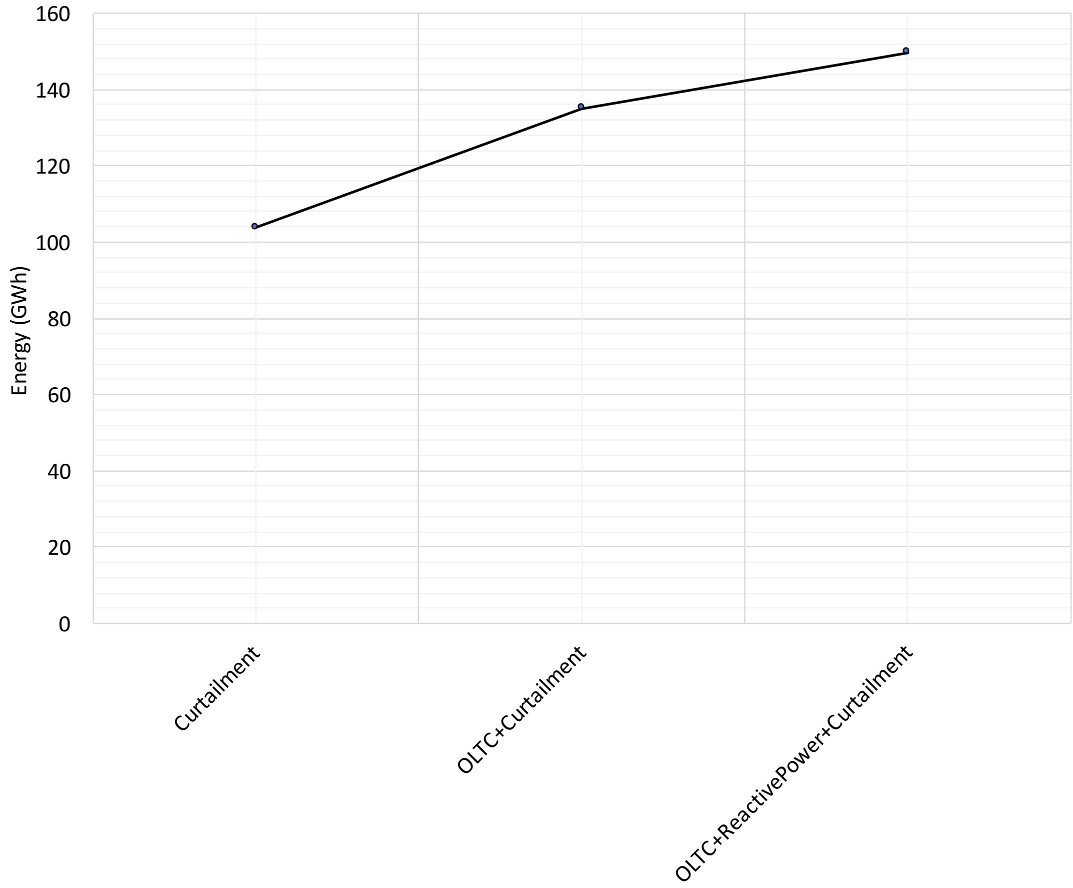


Figure 6.5: Summary of applied CVC techniques

From here it is seen that, wind generation levels increase as we move up the proposed voltage control hierarchy (as seen in section 6.3). The voltage rise limitation for wind farms connected at weak distribution networks is effectively mitigated when the ANM technological solutions are properly coordinated. The proposed ANM solution provides DNOs flexible and alternative control options to address the constraint problem by differing or avoiding the need for capital intensive network reinforcement. It equips DNOs with the appropriate tools to unlock additional network capacity to facilitate greater, cheaper and faster wind connections onto constrained networks. In the context of the wind farm owner/developer, the proposed ANM strategy offers flexible solution for the wind farm owner/developer to control their voltage at the POCs. It provides an opportunity to maximise generation output at a minimum cost when compared to the cost associated with reinforcing the network.

6.3.3 Coordinated voltage control (CVC) + principles of access (PoA)

This section presents results of the non-firm wind generators controlled by ANM solution involving a combination of coordinated voltage control (CVC) and principles of access strategy for controlling voltages and maximising wind generation in active distribution networks. It demonstrates the benefits on wind generation capacities and the economic viability of the non-firm generators when the CVC and PoA strategies are implemented. It presents a detailed assessment and impact on DG capacities in terms of wind energy generation and curtailment levels using an extensive time-series AC optimal power flow (OPF) simulations over a full year.

With the previously discussed CVC configuration of the network model in place, voltage control is achieved by a coordination of centralised control measures including lowering the set-point voltage of the AVC that controls OLTC transformer at the HV/MV primary substation, configuring the reactive power capabilities of the wind turbine generators in combination with active power curtailment of the wind farms. To quantify the benefit and economic viability for future wind farm development and investment, data for average wholesale price of electricity is incorporated in the study. This will help provide investors/stakeholder an indication of potential revenues for wind farm development at the different locations on the network. Half-hourly time-series data for the wholesale price of electricity in the UK over a full year between January to, December 2016 is provided in Figure 6.6.

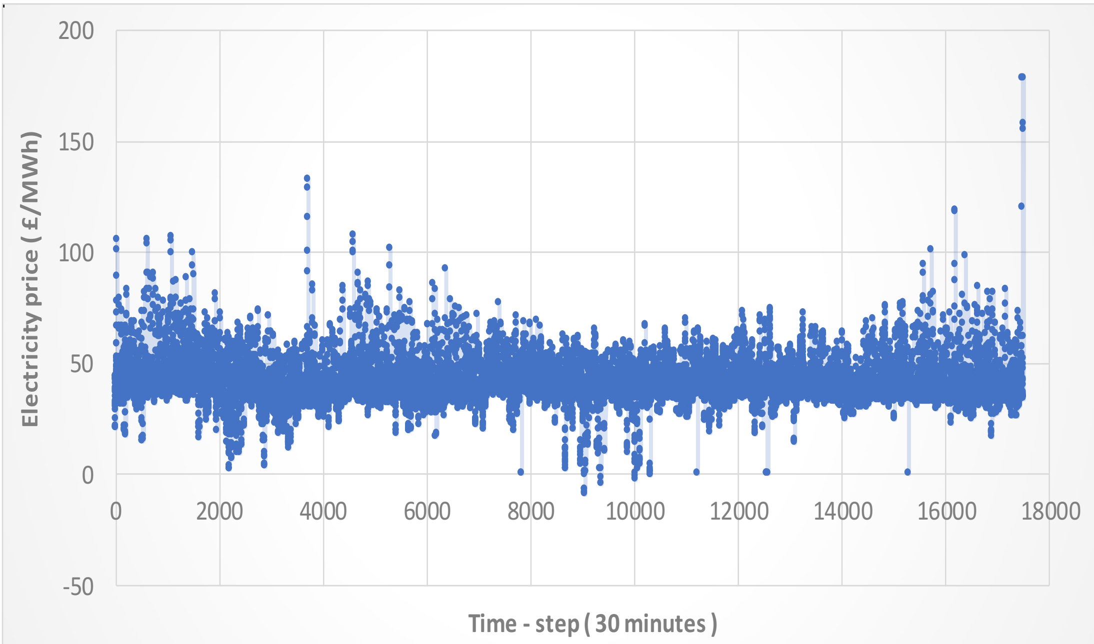


Figure 6.6: APX price of electricity (2016)

To estimate potential revenues for the wind farms, an average whole price of £41/ MWh of electricity is used in conjunction with non-firm generation capacities to provide an indicative annual revenue. Hence;

$$Revenue(\pounds/year) = Average\,price(\pounds/MWh) \times Non\!-\!firm\,generation(MWh) \quad (6.1)$$

Principles of access (PoA) application

In Chapter 3 (section 3.3), PoA was discussed as the rules that define the customers rights to access network capacity and the terms under which the customers rights may be curtailed to alleviate network constraint [20]. They define the relationships between all users (i.e. generators and demand) and available network capacity within an ANM system. In an ANM scheme, the sharing of curtailment or limited capacity among the non-firm generators on the constrained case-study network is implemented by principles of access.

To compare the various merits and drawbacks, five different PoA rules (see Chapter 3) are modelled in combination with the CVC techniques to investigate the potential to effectively mitigate the voltage rise limitation and maximise wind connection output. Each PoA rule quantifies the level of curtailment that would be required by the non-firm DGs to maintain the voltage limits and it investigates subsequent renewable energy yields that may be realised by the generators. With the objectives to control system voltages and maximise wind power output, the order in which the PoA rules are applied is similar to the method outlined in Table 3.2.

6.3.3.1 Last-in-first out (LIFO)

The time-series OPF simulation results shown in Figure 6.7 reveal a total non-firm generation of 111.49 GWh corresponding to 62% energy generation out of 179.39 GWh available energy yielding a total capacity factor of 18.6%. The total curtailment experienced by the DGs were recorded at 38%. Also, the indicative revenue for future wind farm investment decreases steadily as we move further away from the primary substation towards the remote ends of the feeders. The results reveal greater connection capacity for the electrically closest generators to the primary substation. For example, Generator A (10 MW) and generator B (9 MW), higher up on the priority list are observed to generate up to their full installed capacities with maximum capacity factors recorded at 30% with no curtailment experienced. Conversely, greater curtailments are allocated to generators further away from the primary substation. Generator H which has the smallest nameplate capacity and remotely located at the extreme end of feeder 3 is observed to be operating at 6% capacity factor. It is also observed to experience the most curtailment (81%) with the least investment returns when compared with the rest of the non-firm DGs due to poor network location, active generation impact on voltage profile, size and position on the priority stack.

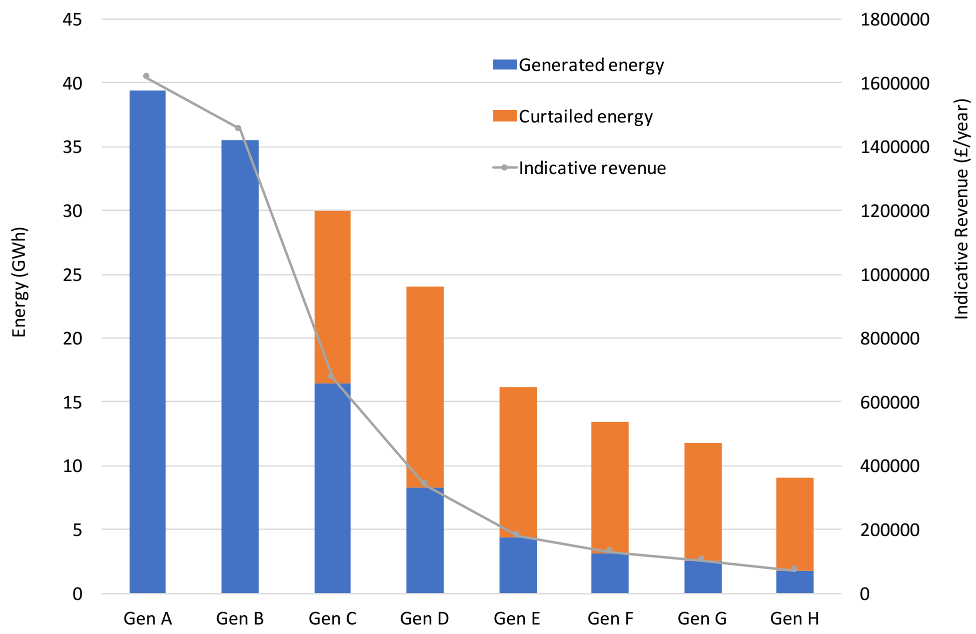


Figure 6.7: Generator performance under CVC + LIFO PoA

6.3.3.2 Reverse LIFO

The simulation results shown in Figure 6.8 reveal a total non-firm generation of 86.3 GWh corresponding to 48% energy generation out of 179.39 GWh available energy yielding a total capacity factor of 14.4%. The total curtailment experienced by the DGs were recorded at 52% which is quite significant when compared with LIFO order discussed. The indicative revenue for future wind farm investment shows fluctuating results and trend as the LIFO priority order is reversed. The results reveal greater network connection capacity to the electrically furthest non-firm wind generator. Here, generator H (2.3 MW) with the first priority order to connect is observed to generate up to a maximum capacity of 99% corresponding to almost 30% capacity factor. Generator A (10 MW) which is the electrically closest with the biggest nameplate capacity (10 MW) is observed to generate up to a maximum capacity of 6% with C.F recorded at 2%. At certain time-steps within the optimisation process, the OPF engine sometimes struggles to maintains the second and third criteria for implementing Reverse LIFO. The OPF assesses available online network capacity and allows DGs access to the network based on active generation impact on the voltage constraint. Active generation at the point of DG connection is proportional to the voltage and line X/R ratios and hence the OPF curtails the generators irrespective of their size and position on the priority list.

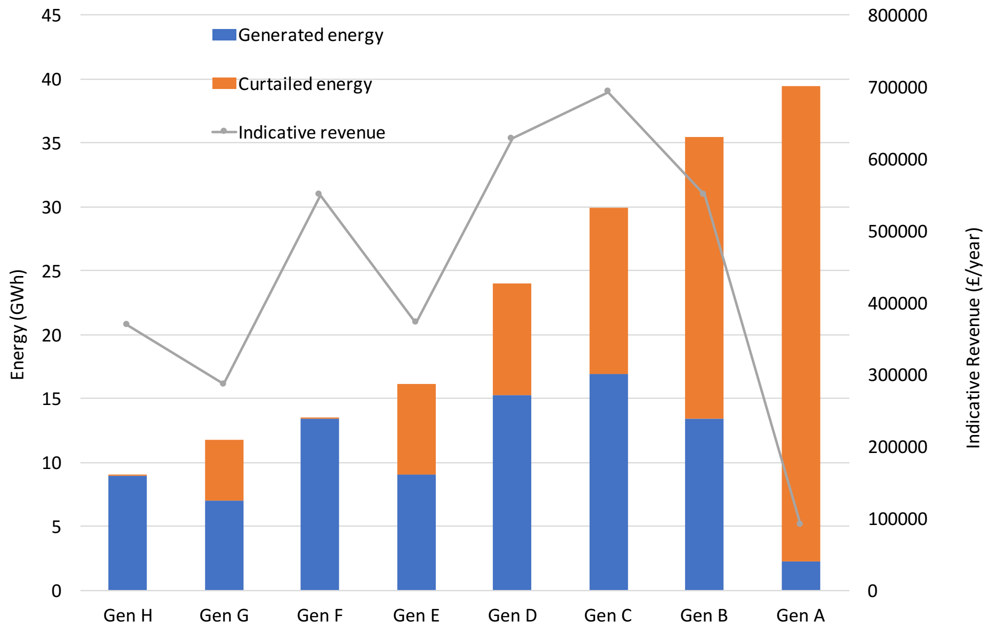


Figure 6.8: Generator performance under CVC + Reverse LIFO PoA

6.3.3.3 Most Convenient

The results shown in Figure 6.9 reveal a total non-firm generation of 109.44 GWh corresponding to 61% energy generation out of 179.39 GWh available energy yielding a total capacity factor of 18.3%. The total curtailment experienced by the DGs were recorded at 39%. Indicative revenue for wind farms connected on feeders with shorter lengths were highly favoured as we move further along towards the remote ends of the feeders. From here it is seen that, greater generation capacities are allocated to DGs connected on feeders with the smallest distance and electrically closer to the primary substation. Generator C (7.6 MW) and generator E (4.1 MW) higher up on the priority list are observed to generate up to full installed capacity with maximum capacity factor recorded at 30%, with no curtailment experienced. Generator H (2.3 MW), which is the smallest size, lowest on the priority list and remotely connected to the weak section of the network, is observed to be generating at 19% of installed capacity with C.F recorded at 6%. It is also observed to experience the most curtailment (81%) when compared with the rest of the non-firm DGs.

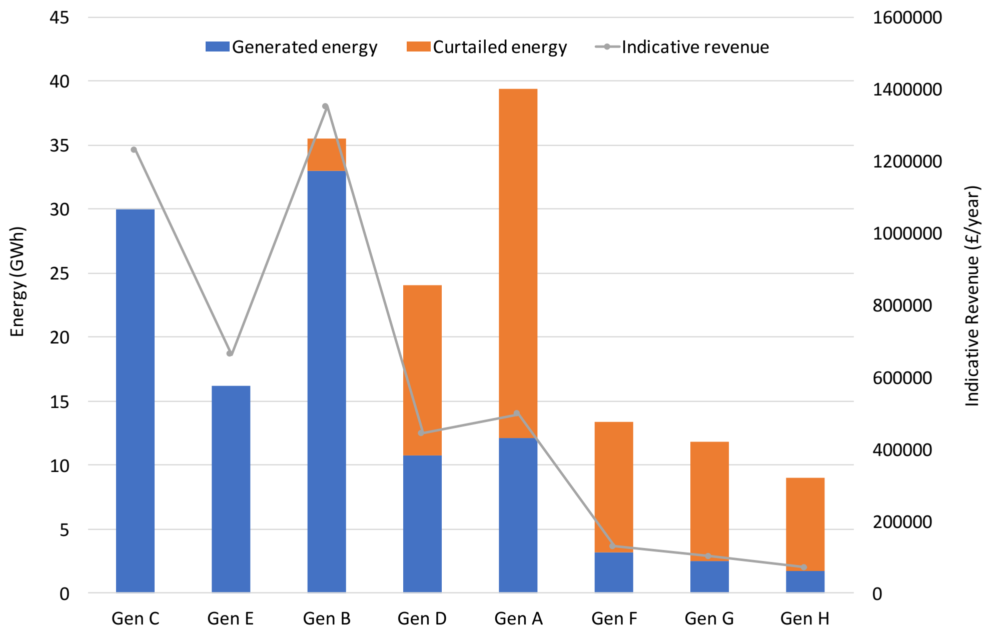


Figure 6.9: Generator performance under CVC + Most Convenient PoA

6.3.3.4 Pro-Rata

The time-series OPF simulation results shown in Figure 6.10 reveal a total non-firm generation of 28.16 GWh corresponding to 16% energy generation out of 179.39 GWh available energy yielding a total capacity factor of 5%. The total curtailment experienced by the DGs were recorded at 84%. Also, the indicative revenue under Pro-Rata PoA for future wind farm investment decreases steadily as we move further away from the primary substation towards the remote ends of the feeders. Under this arrangement, the overall curtailment required to relief the constraint on the network is calculated and shared equally among the wind farms according to their installed capacity and contribution to the constraint.

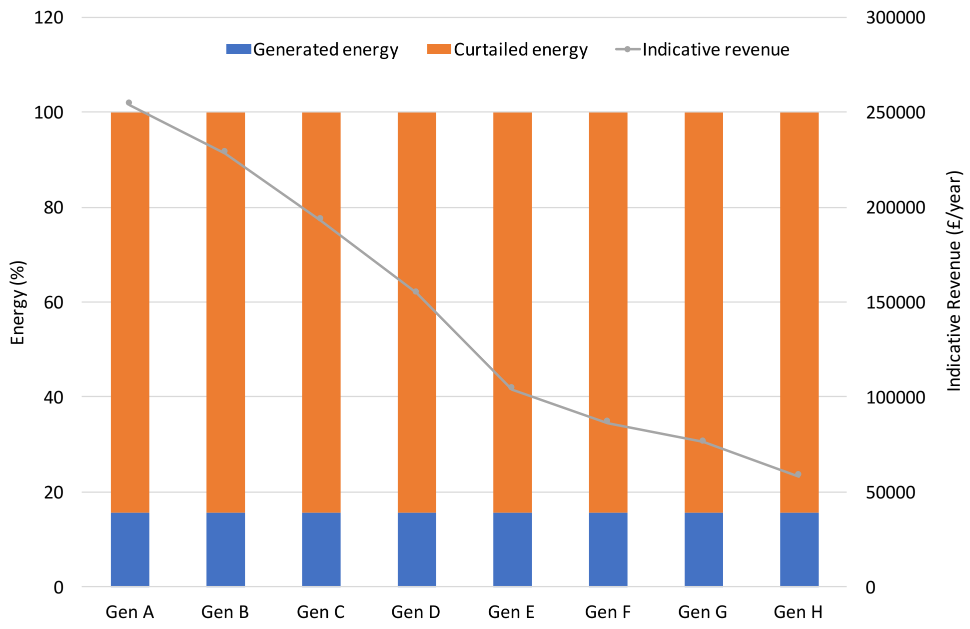


Figure 6.10: Generator performance under CVC + Pro-Rata PoA

6.3.3.5 Enhanced Technical Best

The time-series OPF simulation results reveal a total non-firm generation of 163.31 GWh corresponding to 91% energy generation out of 179.39 GWh available energy yielding a total capacity factor of 27%. The total curtailment experienced by the DGs were recorded at 9%. Also, the indicative revenue for wind farm investment decreases steadily as we move further away from the primary substation towards the remote ends of the feeders. From Figure 6.11, it is observed that results reveal greater connection capacity for all the wind farms connected under Enhanced Technical Best PoA when compared with the rest of the other PoA discussed. The electrically closest generators to the primary substation are highly favoured due to their strong network location. Conversely, the remotely located wind farms connected to the weak sections of the network are observed with improved network access and greater generation capacities when compared with the rest of the other PoA investigated. Generator H (2.3 MW), which has the smallest nameplate capacity and remotely located at the extreme end of feeder 3 is observed to be generating a maximum of 44% of installed capacity.

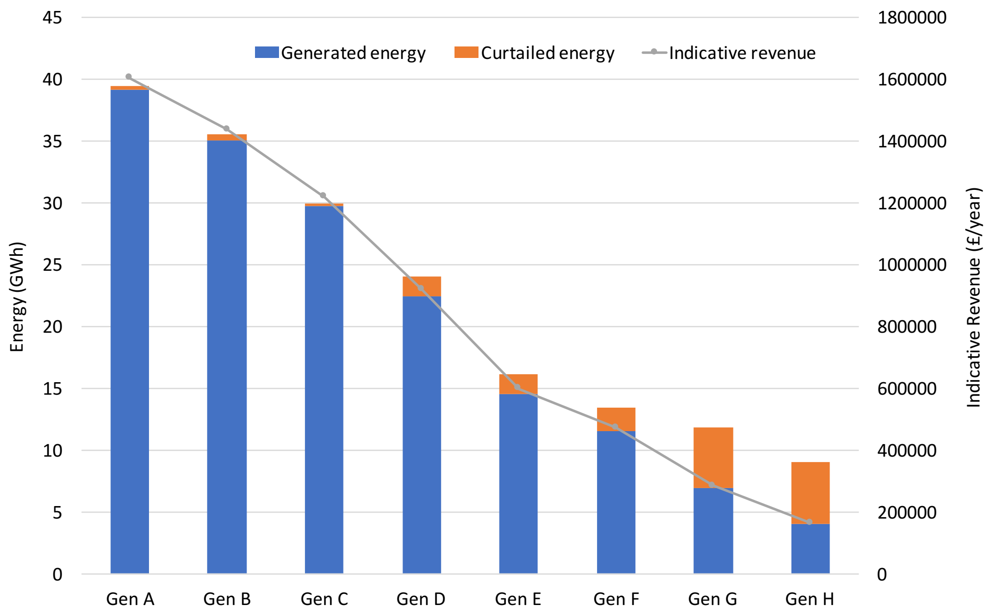


Figure 6.11: Generator performance under CVC + Enhanced Technical Best PoA

6.3.4 Discussion of applied coordinated voltage control (CVC) + principles of access (PoA) techniques

The key task this thesis aim to address is to develop control actions that effectively mitigate the voltage rise limitation at weak distribution networks. It goes further to identify suitable commercial arrangement or PoA for connecting wind farm generators managed under voltage constraint conditions. Where suitable in this context refers to maximising the economic viability of the wind generators (minimising curtailment) whilst maintaining the network constraints within limit. Figure 6.12 presents a summary of the performance of the proposed CVC and PoA strategy when applied to a realistic UK 11 kV distribution network using OPF simulations studies over a full year. The figure quantities the overall wind energy levels realised and the economic benefit for future wind farm investment when the ANM solutions are implemented.

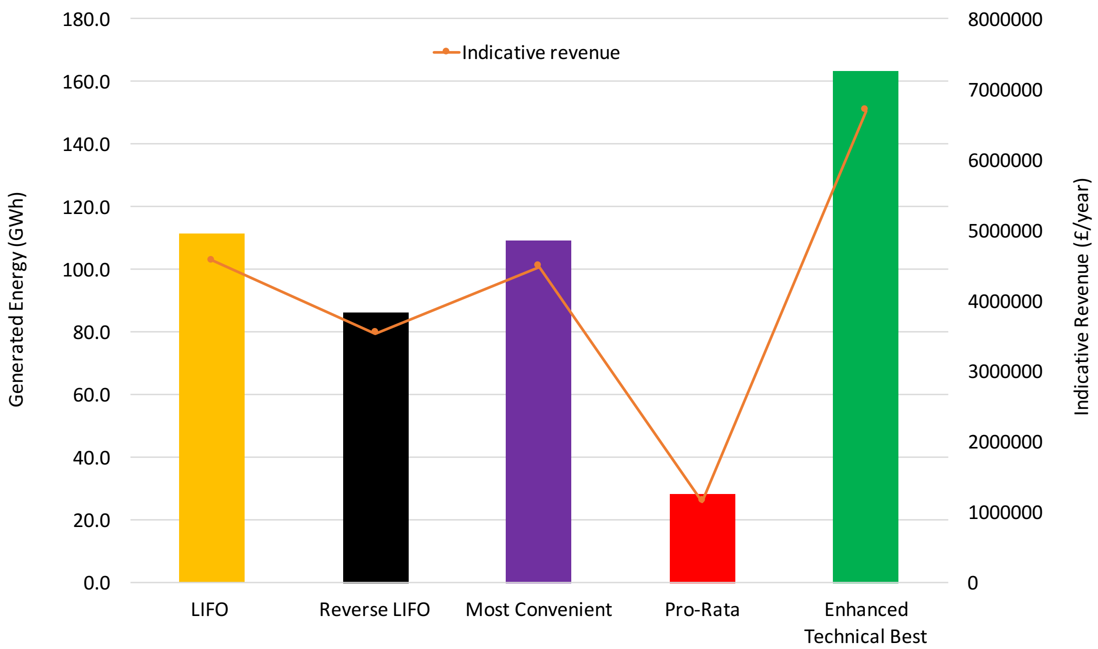


Figure 6.12: Summary of generator performance

Pro-Rata arrangement results in the least amount of wind energy yields and prospective revenue with total generation capacity recorded at 15.7% across the DG units when compared with the rest of the PoA investigated. Pro-Rata arrangement does not fully take account of the impact of the DGs on the voltage profile at different network locations. Furthermore, it does not fully maximise capacities of economically viable wind generators as it treats all the generators equally regardless of their network location when sharing curtailment risk.

Reverse LIFO arrangement yielded a total generation capacity of 48% across the DG units. The case-study criteria for implementing Reverse LIFO provides greater access to DG units connected at the remote and weak sections of the network. Here it is seen that, adopting a Reverse LIFO arrangement underutilises the network headroom capacity resulting in reduced energy yields minimising the economic benefit for the DGs.

The total energy generated across the DG units under Most Convenient PoA was recorded at 61%. In real UK distribution networks, a Most Convenient PoA under thermal constraint conditions is implemented by the network operator to curtail generators they know to be the most convenient to respond to the network constraint. However, in this case-study network where the objective function is to control voltages and minimise generation curtailment, the criteria for implementing Most Convenient PoA was based on feeder lengths as a convenient method to optimally share network capacity. In this case-study network where voltage constraint is binding, Most Convenient PoA is seen as a potential commercial arrangement to optimally allocate curtailment among the non-firm DGs.

Under LIFO arrangement, a total energy generation of 62% was realised across the DG units. Unlike real distribution network where LIFO arrangement is implemented by the date of DG connections. This case-study network assumes an onerous scenario where the date of connection is implemented via electrical distance, size of generators and strength of network at the vicinity of the DGs. In this case-study network where voltage constraint is binding, LIFO rule is seen as a potential arrangement to optimally allocate curtailment among the non-firm DGs.

Enhanced Technical Best (ETB) is observed as the most ideal PoA arrangement for connecting the non-firm DGs when managed under voltage constrained conditions. It is seen to provide the most economic benefit to majority of the wind farms when compared with the rest of the PoA investigated with a total generation capacity recorded at 91%. Here, the generators can effectively mitigate the voltage rise limitation by intelligently switching between VC/RPD - PFC modes to maximise their output. In this arrangement, all the non-firm wind farms have equal priority access to the network and generation capacities are neither influenced by the system operator nor the wind farm owners. The optimisation engine optimally shares curtailment in order of generator's contributions to the constraint, taking full account of the impact of the DG locations on the voltage profiles.

The wind generator units perform differently in terms of energy generation levels when the various PoA techniques are applied to the connect the DGs. To assess the suitability of the PoA for the DG units, each generator is assessed under the different PoA to investigate the impact on generation capacities. Figure 6.13 illustrates the performance of the DG units and corresponding generation levels under the various

PoA investigated.

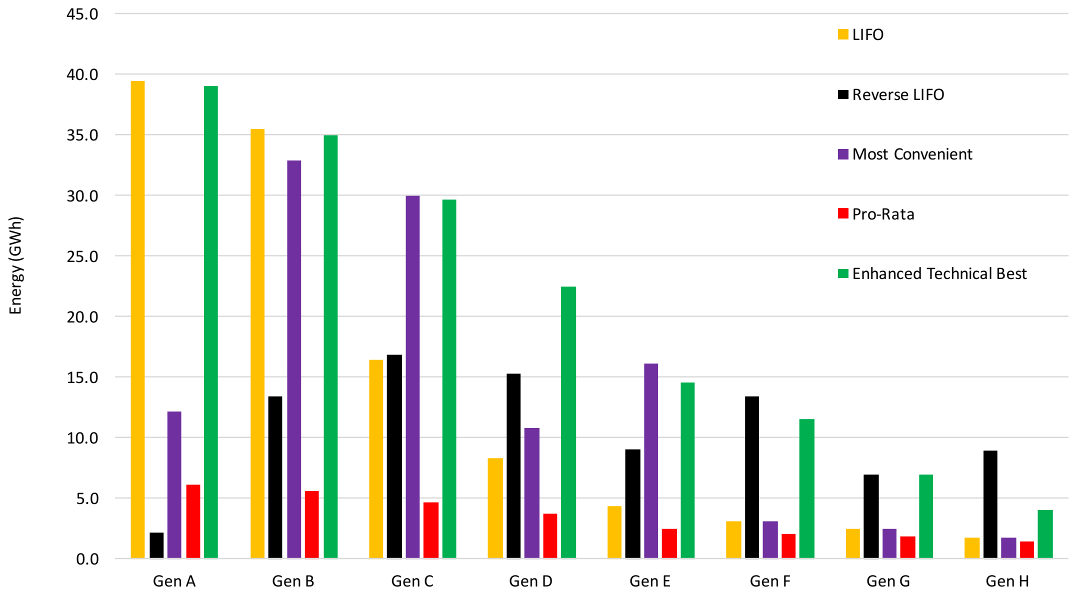


Figure 6.13: Summary of generator performance under PoA

Pro-Rata commercial arrangement is seen not to be suitable to majority of the non-firm DGs in terms of generation levels where network voltage constraint is binding. Pro-Rata on the other hand have been widely implemented in a number of UK ANM schemes (e.g. Flexible Plug and Play project) for sharing curtailment at thermally constrained networks. Reverse LIFO arrangement is observed to be suitable for remotely located generators (Gen H) and does not favour majority of the DG units. Reverse LIFO commercial arrangement where voltage constraint is binding could become useful for small rural community and islanded networks where the lines have similar X/R ratios such that; active generation impact on the voltage profiles are similar.

LIFO and Most Convenient commercial arrangements are seen to favour majority of the DG schemes and are both observed to offer competitive benefits to the generators. LIFO is most beneficial when the criteria adopted in this case study is maintained for future network applications. In contrast with real UK distribution networks, LIFO is implemented by the date of DG connections to the network and could prove less favourable to the DGs when voltage constraint is binding as discussed in [66].

Most Convenient on the other hand provided competitive benefit to majority of the DG schemes as the criteria for implementing it was system operator led and primarily based on feeder lengths as a convenient method to optimally share network capacity.

Enhanced Technical Best (ETB) commercial arrangement is seen to provide the most economic benefit to all the DG units. The ETB arrangement is seen to favour majority of the wind farms and deemed a suitable commercial arrangement for connecting the non-firm generators onto the network when managed under voltage constraint conditions. The ETB arrangement fully utilises proactive curtailment techniques by assessing available online network capacity and allowing the optimisation engine to optimally allocate curtailment in order of DGs contribution to the constraint while taking into full account, the impact of the DGs on the voltage constraint based on their location. It also utilises the ability of the DGs to mitigate the constraint by employing the inherent reactive power capabilities to enhance generation capacities.

6.4 Summary

The proposed ANM solution for the key research question adopts a hierarchical and systematic approach to implementing the control actions with overall objective of maximising wind farm connection capacities. This section of this thesis has presented and demonstrated the benefit of the proposed voltage control techniques on a generic UK distribution network. The base-case test network presented in this chapter serves as a benchmark to assess the effectiveness and robustness of the proposed ANM solution for future distribution network operations (Chapter 7).

Five different PoA rules currently deployed at thermally constrained distribution networks have been applied to connect the wind farms under voltage constraint conditions. Extensive simulations are performed over a full-year and the results obtained are assessed and analysed. With objective to maximise the overall wind energy levels, each PoA rule quantifies the potential wind generation capacities that may be realised by the non-firm DGs and the economic viability for wind investment when the ANM solutions are implemented.

The novel ANM solutions presented in this section provides DNO's flexible control options to address the voltage rise constraint problem. It offers wind farm owners, flexible options to control their voltage at the POC's to minimise adverse curtailment and an opportunity to enhance their generation output at a minimum cost. It provides headlights and a guide for future wind farm developers on suitable locations to invest and provides an indication of the potential revenue and curtailment risks. It quantities the risks and uncertainties associated with the different commercial arrangement and proposes alternative PoA specific for voltage constrained networks.

Chapter 7

ASSESSMENT OF COORDINATED VOLTAGE CONTROL AND PRINCIPLES OF ACCESS TECHNIQUES UNDER CHANGES IN NETWORK CONDITIONS

7.1 Introduction

The base-case studies previously presented in Chapter 6 serves as a benchmark to assess the effectiveness of the proposed CVC and PoA solution for distribution networks. It provides a basis to compare, validate and evaluate the robustness of the proposed strategy when applied under certain likely changes in future network operation conditions.

In this chapter, we take a closer look and undertake a comparative study between the commercially viable principles of access arrangements. Previous studies undertaken in Chapter 3 and Chapter 6 of this thesis has identified the Last-in-First Out (LIFO), Most Convenient (MC) and the Enhanced Technical Best (ETB) arrangements as the most commercially viable PoA arrangement that can be applied to manage the connection of wind generators under network voltage constraint conditions. Here, we undertake a quantitative analysis to assess the benefit and impact of the CVC and PoA on the wind farms as certain key changes occur in the network's future operations. Here, the connection agreement for the wind farms are maintained under non-firm contracts such that, their power output can be constrained off (trip or trim) in the event of a network constraint. All the wind farms are also assumed to be equipped with modern wind turbine technologies and reactive power capabilities that allows them to participate in voltage control and grid reactive power support on the network. The key changes in network conditions identified and most likely to occur are discussed under the following headings:

1. Future repowering opportunities for remotely connected wind farms
2. Addition of future wind farm development at random locations on the network
3. Further wind farm development at strong bus locations with exiting wind farms

The following sections present and discusses the studies undertaken for likely future changes in network operation conditions. It quantifies the benefits of the three potential PoA arrangement in terms of the overall wind generation capacities realised under each arrangement when the changes are implemented. The study goes further to assess the performance of the generators under each PoA arrangement when the future changes are applied under network voltage constraint conditions.

7.2 Repowering opportunities for remotely connected wind farms

Repowering is the process of replacing old wind turbine fleet with the latest technology or installing additional wind capacities to achieve greater nameplate capacity. Upgrading or replacing existing wind turbines as they reach the end of their operational lives can provide a cost-effective way to enhance low carbon electricity generation. Repowering older wind turbines is becoming a common practice in developed countries (especially in the UK, Germany and the US) as wind turbine technology advances. Newer turbines tend to be large scale multi-megawatt capacities installed at greater heights, allowing for more efficiency and capacity per turbine. More wind power from the same area of land is multiplied without the need for additional land space.

Repowering can increase the output of a wind farm, improve reliability and extend the life-span by taking full advantage of recent advancement in the technology. Replacing old turbines with state-of-the-art advanced technology are able to provide required grid support services, to ensure a better integration of the variable wind resource into electricity grids when compared to first or second-generation machines.

7.2.1 Network description

In this configuration, the existing network set-up, input variables (including load profiles) and operation conditions remains the same as the base-case model presented in Chapter 6. However, the new changes in network conditions involves the addition of a 3.9 MW capacity to the existing 45.5 MW network capacity through incentivised Repowering opportunities for the remotely connected wind farms. The remote wind farms identified includes; generator E (4.1 MW), generator F (3.4 MW), generator G (3.0 MW) and generator H (2.3 MW). The existing nameplate capacities are to be repowered to achieve a total network capacity of 49.4 MW. The four nominated generators are marked in green circles and connected at nodes 1120, 1310, 1358, 1387 and are assumed to operate an ANM scheme as shown in the single line diagram in Figure 7.1. These have now been renamed as Gen E1, Gen F1, Gen G1 and Gen H1.

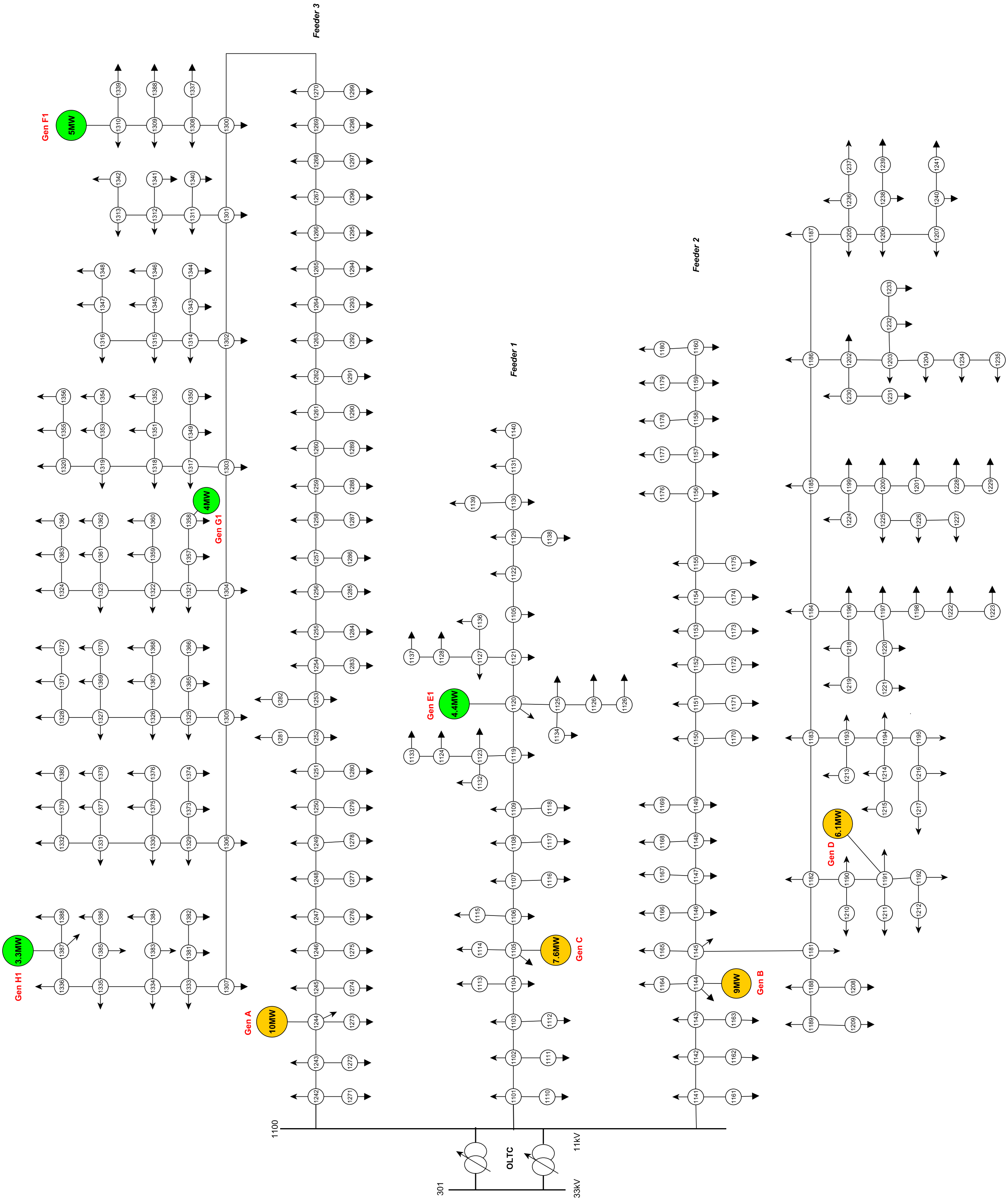


Figure 7.1: 11 kV radial distribution network

7.2.2 Wind connection capacities

In this arrangement, the planning tool to determine the additional generation capacities on the 11 kV test network is similar to that discussed in Chapter 3. A summary of the DG capacities are provided in Table 7.1 with the repowered wind farms marked in bold.

Table 7.1: Summary of existing and repowered wind farms

Generator	Capacity (MW)	Bus No	Technology
Gen A	10.0	1244	Wind
Gen B	9.0	1144	Wind
Gen C	7.6	1105	Wind
Gen D	6.1	1191	Wind
Gen E1	4.4	1120	Wind
Gen F1	5.0	1310	Wind
Gen G1	4.0	1358	Wind
Gen H1	3.3	1387	Wind

7.2.3 Wind generation capacities under repowering opportunities

With optimisation objectives to maximise wind generation output whilst controlling network voltages, a time-series ACOPF simulation under each of the PoA configuration is run for a full year at half-hourly time-steps (17520 time-steps in total). It should be noted here that, the criteria for implementing LIFO, MC and ETB principles of access remains the same as discussed in Chapter 3. A summary of the table of results are presented in Appendix E.

Figure 7.2 presents a summary of the overall wind energy capacities realised under the three main principles of access studied. Here, we assess the overall performance of the wind generators in terms of the total energy levels realised when the various PoA techniques are applied to the connect the DGs. From here, MC and LIFO are seen to offer competing benefits with 1% marginal difference between them. However, it is clearly seen that ETB principles of access arrangement provides the most economic benefit to the wind farms when compared with the rest of the other two PoA investigated. A 28% increase in generation is realised when benchmarked with MC with a total potential indicative revenue recorded at £6.8 million/year for the generators.

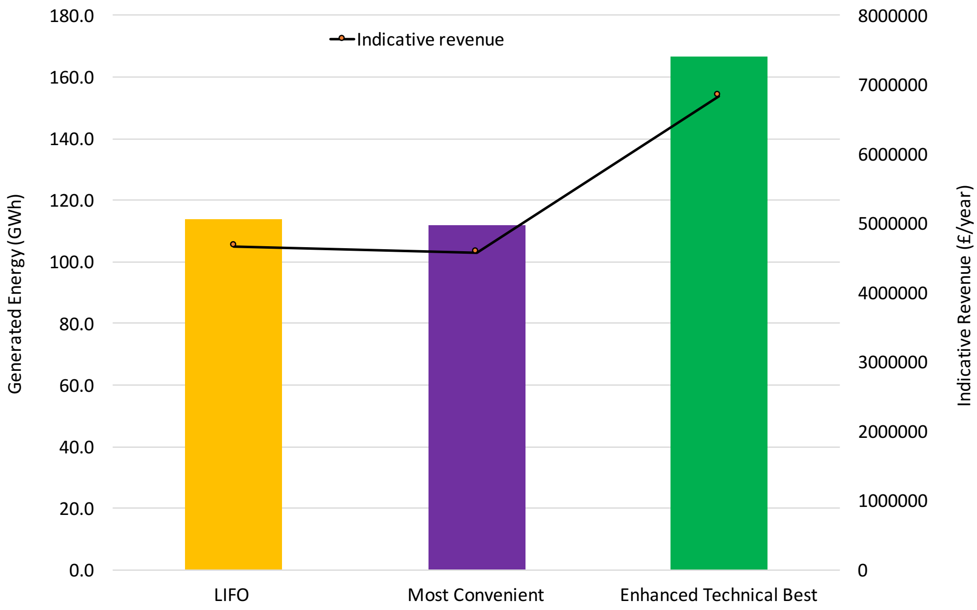


Figure 7.2: Total wind generation capacities under repowering opportunities

7.2.3.1 Last-in-first out (LIFO)

In this configuration, the priority positions for the existing and repowered generators are maintained and remains the same. In others words, the repowered generators with additional capacities are able to keep their positions on the list as before. The time-series ACOPF simulation results reveal a total non-firm generation of 113.97 GWh of energy realised under LIFO arrangement corresponding to a total generation capacity of 58.5% energy generation out of 194.77 GWh available energy. The total curtailment experienced by the DGs were recorded at 41.5% as summarised in Table E.1. Also, the indicative revenue for wind farm investment decreases steadily as we move further away from the primary substation towards the remote ends of the feeders.

7.2.3.2 Most Convenient (MC)

Here, the priority positions for the existing and repowered generators is maintained and remains unchanged. At the end of the ACOPF it is observed that, a total non-firm generation of 111.81 GWh of energy was realised corresponding to a total generation capacity of 57.4% energy generation out of 194.77 GWh available energy. The total curtailment experienced by the DGs were recorded at 42.6% as seen in Table E.2. Also, the indicative revenue for the wind farm connected on the feeder with shorter lengths were highly favoured as we move towards the remote ends of the feeders.

7.2.3.3 Enhanced Technical Best (ETB)

Under ETB arrangement, the criteria for connecting the new non-firm generators is summarised in Table 3.2 where all the generators have equal priority access to the network. At the end of the full year simulation, a total non-firm generation of 166.81 GWh of energy was realised corresponding to a total generation capacity of 85.6% energy generation out of 194.77 GWh available energy. The total curtailment experienced by the DGs were recorded at 14.4% as seen in Table E.3. Also, the indicative revenue for wind decreases steadily as we move further away from the primary substation towards the remote end of the feeders.

7.2.4 Generator performance under repowering opportunities

To assess the suitability of the PoA for the DG units, each generator is assessed under the different PoA to investigate the impact on generation capacities. It should be noted that the wind generators perform differently in terms of generation and curtailment levels when the three PoA techniques are applied. To assess the suitability of the PoA for the DG units, each generator is assessed under the different PoA rule to investigate the impact on generation capacities. Figure 7.3 illustrates the performance of the DG units and corresponding generation levels under the various PoA rule investigated.

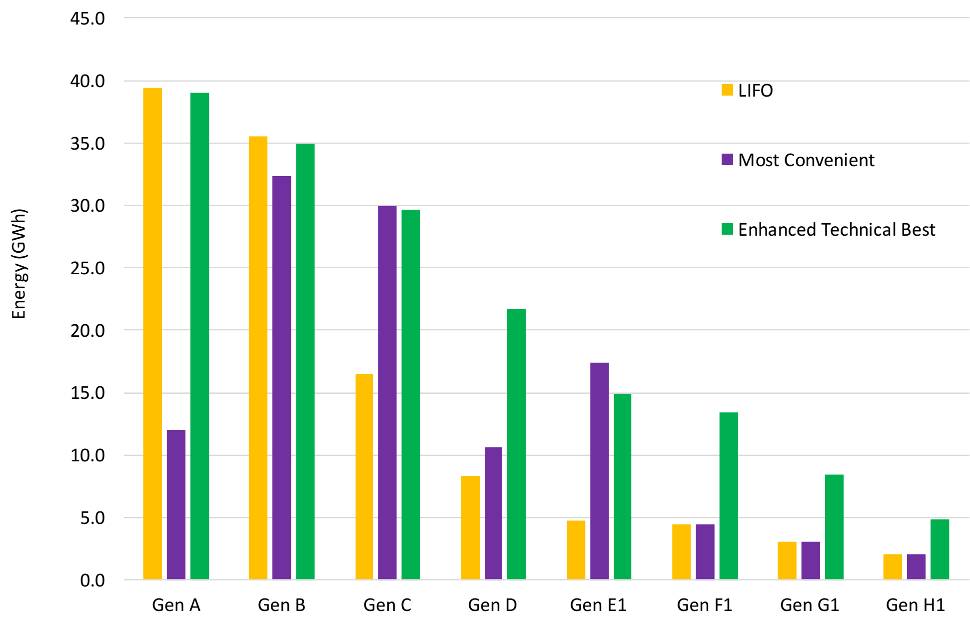


Figure 7.3: Generator performance under repowering opportunities

From here, it is seen that ETB is the preferred option as it provides the most economic benefit to the DG units for future repowering changes that are likely to occur on the network. It is seen to favour majority of the wind farms and considered a suitable commercial arrangement for connecting the non-firm generators managed under voltage constraint conditions when these changes occur in the future.

7.3 Additional wind farm development at random bus location

In this study it is assumed that, future network changes will involve an additional 20.4 MW onshore wind generation capacity added to the existing 49.4 MW capacity on the 11 kV network. It is also assumed that, the distribution network operator (DNO) has statutory duties to offer terms to connect the new non-firm wind farms to the existing distribution network. The options presented in this study addresses the connection offers and the implications to the wind farm generators under such conditions.

7.3.1 Network description

With the existing repowering network configuration in place, four new additional non-firm wind farms development are added at random locations on the network. The additional wind farms vary in size and are dispersed over a wide area to collect and transport electricity to the network and are marked with red circles at nodes 1199, 1140, 1299, and 1377 as shown in the single line diagram in Figure 7.4. The new non-firm wind farms with varied capacities includes generator I (5.1 MW), generator J (2.5 MW), generator K (8.5 MW) and generator L (3.7 MW) and are assumed to be connected to an ANM scheme. The existing network set-up such as, input variables (including load profiles) and operation configuration remains the same as the repowering network model.

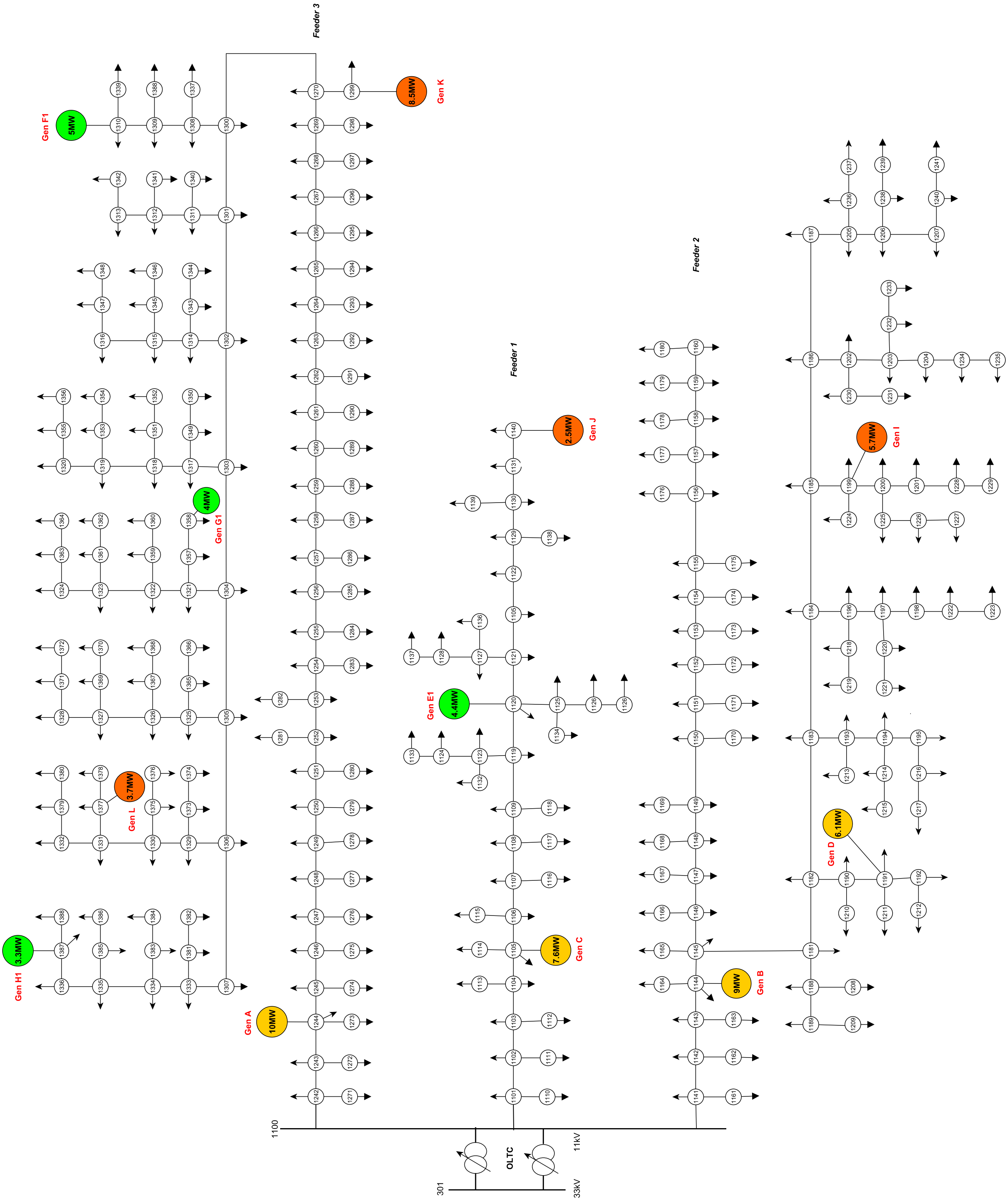


Figure 7.4: 11 kV radial distribution network

7.3.2 Wind connection capacities

Wind connection capacities for the four new additional wind farms are determined using the procedure discussed in Chapter 3. A summary of the twelve total non-firm DG capacities are provided in Table 7.2, with the additional wind farms marked in bold.

Table 7.2: Summary of existing and additional wind farms at random bus location

Generator	Capacity (MW)	Bus No	Technology
Gen A	10.0	1244	Wind
Gen B	9.0	1144	Wind
Gen C	7.6	1105	Wind
Gen D	6.1	1191	Wind
Gen E1	4.4	1120	Wind
Gen F1	5.0	1310	Wind
Gen G1	4.0	1358	Wind
Gen H1	3.3	1387	Wind
Gen I	5.1	1199	Wind
Gen J	2.5	1140	Wind
Gen K	8.5	1199	Wind
Gen L	3.7	1377	Wind

7.3.3 Wind generation capacities under additional wind farm development at random bus location

With optimisation objectives to maximise wind generation output whilst controlling network voltages, a time-series ACOPF simulation under each of the principles of access (PoA) configuration is run for a full year at half-hourly time-steps (17520 time-steps in total). The criteria for implementing LIFO, MC and ETB principles of access maintained as discussed Chapter 3. Appendix E provides a summary of the table of results.

A summary of the overall wind energy capacities realised under the three main principles of access studied under the likely change in network conditions is presented in Figure 7.5. The overall performance of the wind generators in terms of the total energy levels realised when the various PoA techniques are applied to the connect the DGs are assessed. From here, MC and LIFO are offering competing benefits with similarities in generation capacities between them. Enhanced Technical Best POA arrangement is clearly seen to provide the most economic benefit to the wind farm generators when compared with the rest of the other two PoA investigated. A 26% increase in generation is realised when benchmarked with MC with a total potential indicative revenue recorded at almost £8 million /year for the generators.

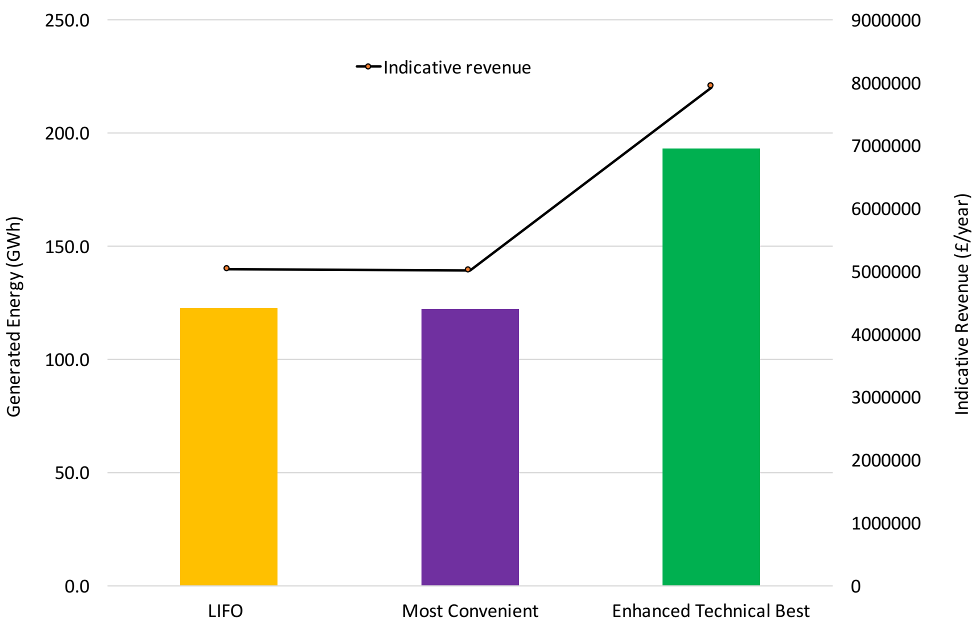


Figure 7.5: Total wind generation capacities: addition of new wind farms at random location

7.3.3.1 Last-in-first out (LIFO)

In this PoA configuration, the existing eight generators have their priority positions maintained and kept in place. The criteria for connecting the additional four new non-firm generators to the network is based on Table 3.2. The time-series ACOPF simulation results reveal a total non-firm generation of 122.71 GWh of energy realised under LIFO arrangement corresponding to a total generation capacity of 44.6% energy generation out of 275.20 GWh available energy. The total curtailment experienced by the DGs were recorded at 55.4% as summarised in Table E.4. Also, the indicative revenue for wind farm investment decreases steadily as we move further away from the primary substation towards the remote ends of the feeders.

7.3.3.2 Most Convenient (MC)

In this PoA arrangement, the criteria for connecting the additional four new non-firm generators is based on Table 3.2. Here, the existing eight generators on the network have their priority positions maintained and kept in place. At the end of ACOPF simulation, a total non-firm generation of 122.31 GWh of energy was realised corresponding to a total generation capacity of 44.4% energy generation out of 275.20 GWh available energy. The total curtailment experienced by the DGs were recorded at 55.6% as seen in Table E.5. Also, the indicative revenue for wind farm connected on the feeder with shorter lengths were highly favoured as we move towards the remote ends of the feeders.

7.3.3.3 Enhanced Technical Best (ETB)

In this arrangement, the criteria for connecting the non-firm generators is summarised in Table 3.2 where all the generators have equal priority access to the network. The full year simulation revealed a total non-firm generation of 193.27 GWh of energy corresponding to a total generation capacity of 70.2% energy generation out of 275.20 GWh available energy. The total curtailment experienced by the DGs were recorded at 17.1% as seen in Table E.6. Also, the indicative revenue for wind decreases steadily as we move further away from the primary substation towards the remote end of the feeders.

7.3.4 Generator performance under additional wind farm development at random bus location

Figure 7.6 illustrates the performance of the DG units and corresponding generation levels under the various PoA investigated. From here, it is seen that under the new changes in future network conditions where new wind farms developments are randomly connected to the network, the ETB provides the most economic benefit to the DG units. It favours majority of the wind farms and considered a suitable commercial arrangement for connecting the non-firm generators managed under voltage constraint conditions when these changes occur in the future.

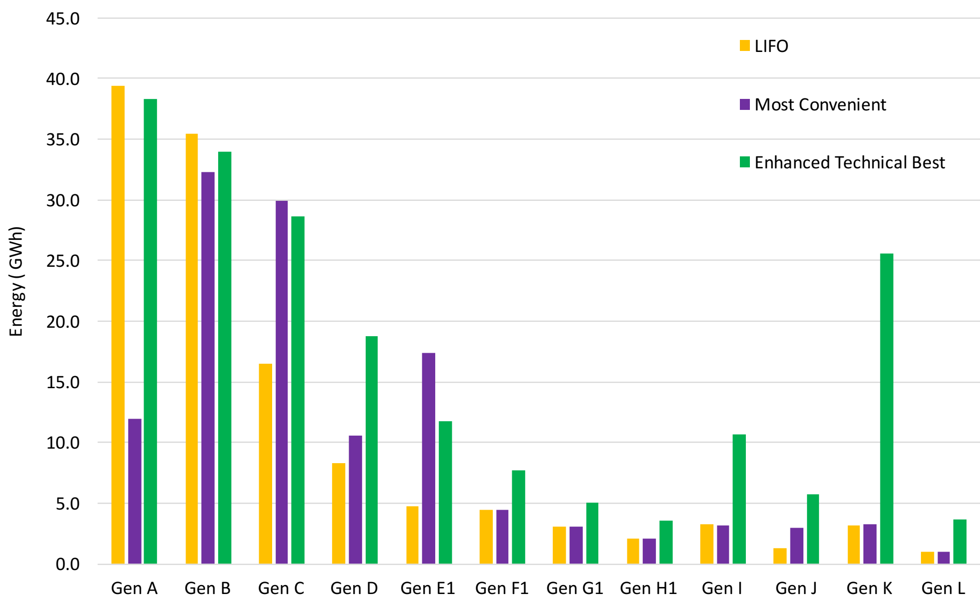


Figure 7.6: Generator performance: addition of new wind farms at random location

7.4 Further wind farm development at strong bus location with existing wind farms

With the UK's future intentions to accelerate renewable connections, this study assumes the DNO has statutory duties to connect a further 31.8 MW of wind generation to its existing 69.8 MW capacity. Here, it is assumed that connection offers have been granted to a number of new wind farm developers/investors wishing to connect to the existing ANM scheme. The total wind generation capacity on the network is currently recorded at 101.6 MW with the new additions. This section presents the PoA options to connect the new non-firm (NNF) wind farms to the existing 11 kV distribution network and to assess the implications on both existing and new generators.

7.4.1 Network description

In this configuration, the existing network set-up described earlier in section 7.3 (with a total of twelve generators) is maintained. However, the new changes in network conditions involves the addition of four new non-firm wind farm development connected at the strong sections of the network. The additional wind farm nameplate capacities vary in size and are deliberately connected to the strong sections of the network where they share common bus connection points with existing wind farms closer to the primary substation. They are marked with light blue circles at nodes 1244, 1144, 1105, and 1191 as shown on the single line diagram in Figure 7.7. The new non-firm wind farms with varied capacities includes generator M (9.5 MW), generator N (8.8 MW), generator O (7.0 MW) and generator P (6.5 MW) and are assumed to operate an ANM scheme. The existing network set-up such as input variables (including load profiles) and operation configuration remains the same as the previous model in section 7.3.

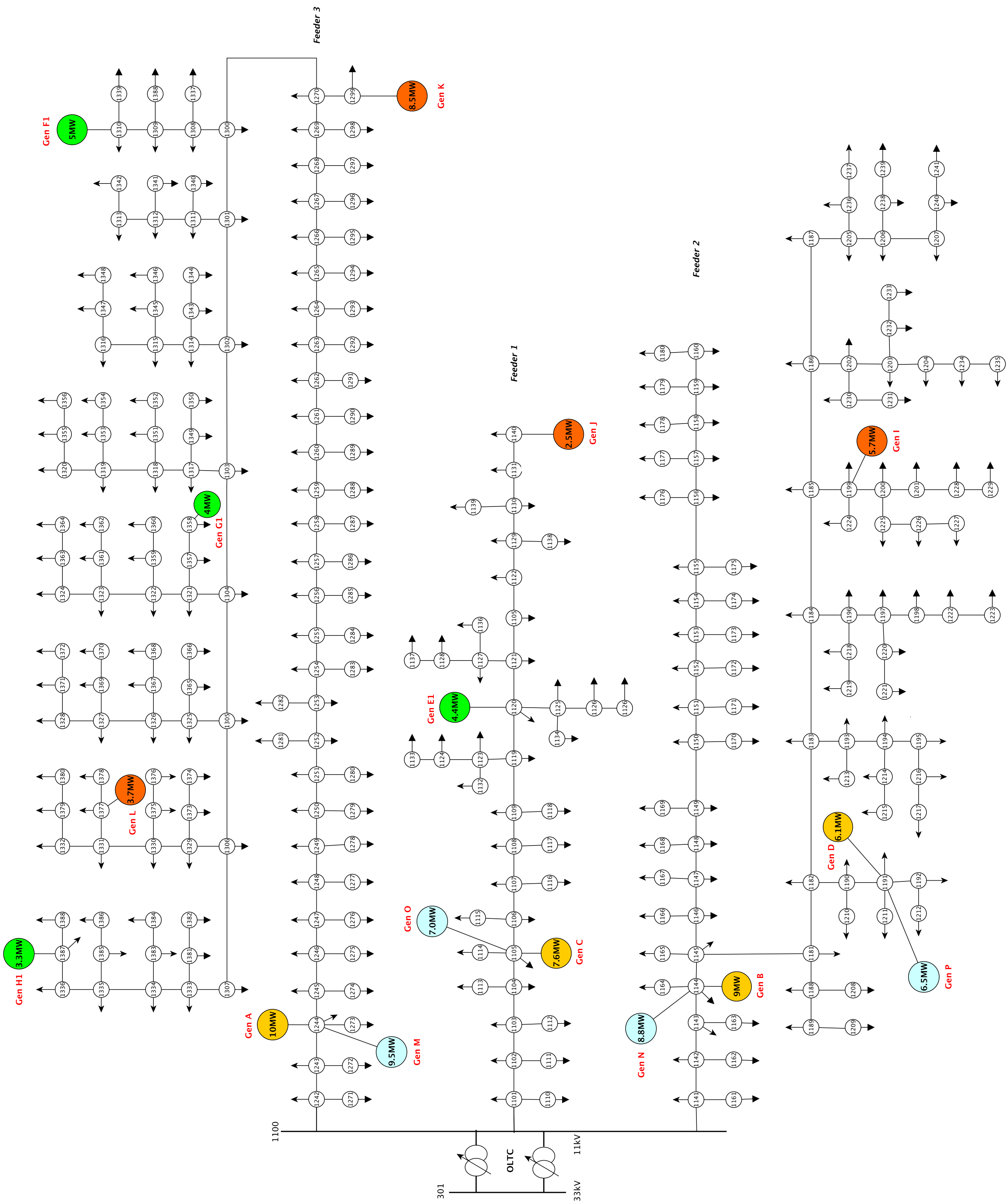


Figure 7.7: 11 kV radial distribution network

7.4.2 Wind connection capacities

A summary of the sixteen total non-firm DG capacities are provided in Table 7.3, with the additional wind farms marked in bold.

Table 7.3: Summary of existing and additional wind farms at same bus location

Generator	Capacity (MW)	Bus No	Technology
Gen A	10.0	1244	Wind
Gen B	9.0	1144	Wind
Gen C	7.6	1105	Wind
Gen D	6.1	1191	Wind
Gen E1	4.4	1120	Wind
Gen F1	5.0	1310	Wind
Gen G1	4.0	1358	Wind
Gen H1	3.3	1387	Wind
Gen I	5.1	1199	Wind
Gen J	2.5	1140	Wind
Gen K	8.5	1199	Wind
Gen L	3.7	1377	Wind
Gen M	9.5	1244	Wind
Gen N	8.8	1144	Wind
Gen O	7.0	1105	Wind
Gen P	6.5	1191	Wind

7.4.3 Wind generation capacities under further wind farm development at same bus location

In this configuration, the optimisation objective is to maximise wind generation output whilst controlling network voltages. A time-series ACOPF simulation under each of the principles of access (PoA) configuration is run for a full year at half-hourly time-steps (17520 time-steps in total). The criteria for implementing LIFO, MC and ETB principles of access is maintained as discussed in the base-case model in Chapter 3.

A summary of the table of results are presented in Appendix E. To discuss the merits of the three main PoA studied, a summary of the total energy realised under each commercial arrangement is presented in Figure 7.8. From here, MC and LIFO are observed to be offering competing benefits with similarities in generation capacities. The ETB arrangement is clearly seen to provide the most economic benefit to the wind farm generators when compared with the rest of the other two PoA investigated. A 26% increase in energy generation is realised under ETB when benchmarked with MC. A total indicative revenue for the generators is recorded at £9 million/year.

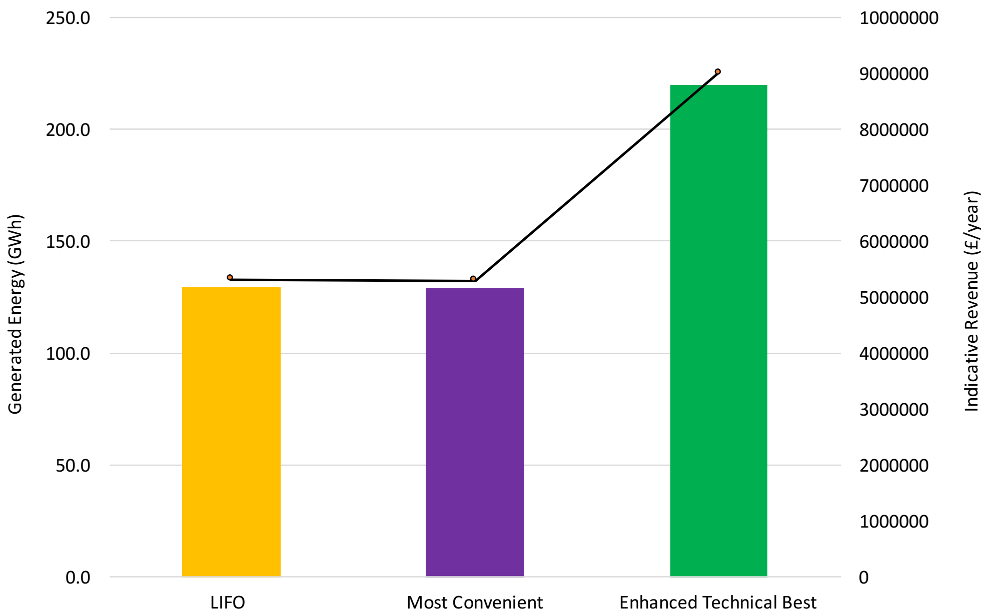


Figure 7.8: Total wind generation capacities: addition of new wind farms at strong bus location

7.4.3.1 Last-in-first out (LIFO)

With the existing twelve generators and their priority positions in place, the criteria for connecting the additional four new non-firm generators to the network is based on Table 3.2. The time-series ACOPF simulation results reveal a total non-firm generation of 129.71 GWh of energy realised under LIFO arrangement corresponding to a total generation capacity of 32.4% energy generation out of 400.58 GWh available energy. The total curtailment experienced by the DGs were recorded at 67.6% as summarised in Table E.7. Also, the indicative revenue for wind farm investment decreases steadily as we move further away from the primary substation towards the remote ends of the feeders

7.4.3.2 Most Convenient (MC)

Under MC principles of access arrangement, the criteria for connecting the additional four new non-firm generators is based on Table 3.2. Here, the existing twelve generators on the network have their priority positions maintained and kept in place. At the end of the ACOPF, a total non-firm generation of 129.13 GWh of energy was realised corresponding to a total generation capacity of 32.2% energy generation out of 400.58 GWh available energy. The total curtailment experienced by the DGs were recorded at 67.8% as seen in Table E.8.

7.4.3.3 Enhanced Technical Best (ETB)

Under ETB arrangement, the criteria for connecting the new non-firm generators is summarised in Table 3.2 where all the generators have equal priority access to the network. At the end of the ACOPF, a total non-firm generation of 219.66 GWh of energy was realised corresponding to a total generation capacity of 54.8% energy generation out of 400.58 GWh available energy. The total curtailment experienced by the DGs were recorded at 45.2% as seen in Table E.9. The indicative revenue for the wind farms decreases steadily as we move further away from the primary substation towards the remote end of the feeders.

7.4.4 Generator performance under further additional wind farm development at strong bus location

The generator units behave differently when the principles of access are implemented. To quantify the benefits of the PoA to the generators, Figure 7.9 illustrates the performance of the DG units and corresponding generation levels achieved under each commercial arrangement. From here it can be observed that, the Enhanced Technical Best arrangement provides the most economic benefit to the DG units for future network changes where new wind farms are connected at the same bus with existing ones. It is seen to favour majority of the wind farms and considered a suitable commercial arrangement for voltage constraint networks when such changes occur in the future.

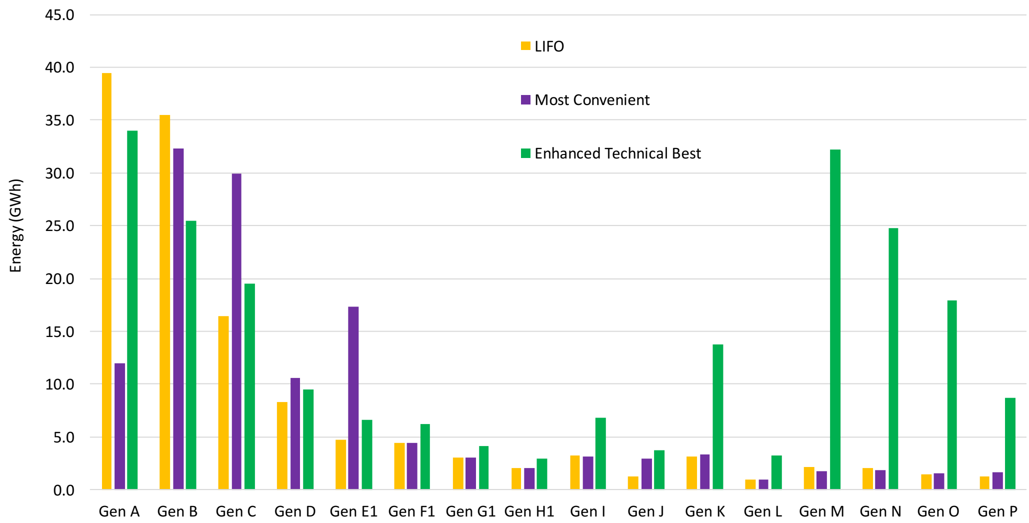


Figure 7.9: Generation performance: addition of new wind farms at strong bus location

7.5 Discussion of principles of access under changes in network conditions

This thesis aim to investigate suitable PoA arrangements for connecting wind farm generators managed under voltage constraint conditions at weak distribution networks. With objectives to maximise wind generation capacities whilst maintaining network constraint limits, this chapter has presented an assessment of the potential PoA arrangements that can be adopted for non-firm wind farm connections at voltage constrained networks. The study has investigated and modelled likely future changes in network conditions and assessed the merits and viability of the PoA against such conditions.

The assessment of the PoA with changes in network conditions is benchmarked with the base-case model presented in Chapter 6. The total wind generation capacities increase as new wind farm developments connects to the 11 kV distribution network. The last-in-first out (LIFO) and Most Convenient (MC) connection arrangements are seen to offer competing benefits under all network conditions and operational scenarios however, their economic benefits depends on the DNO making the most appropriate priority order arrangement for connecting the generators. Under LIFO and MC commercial arrangements, high priority order generators tend to operate in strictly capacitive mode to correct their terminal voltage and maximise their output, leaving the lower priority generators unable to participate in network PFC-VC/RPD but to heavily curtail their active power output resulting in the overall reduction in generation capacities.

Enhanced Technical Best connection arrangement is seen to provide the most economic benefit under all changes in network conditions. In this arrangement, all the non-firm wind farms have equal priority access to the network and generation capacities are neither influenced by the system operator nor the wind farm owners. The optimisation engine optimally shares curtailment in order of generator's contributions to the constraint, taking full account of the dynamic impact of the DG locations on the voltage profile. All the non-firm DGs able to effectively mitigate the voltage rise limitation by intelligently switching between VC/RPD - PFC modes to maximise their output. By so doing, it provides an improved network access to the remotely connected DGs when compared with LIFO and MC. Enhanced TB arrangement minimises grid import of reactive power as DGs are able to support network reactive demands and other ancillary services. The Enhanced Technical Best (ETB) is seen as the most ideal PoA arrangement for connecting the non-firm DG managed under voltage constraint conditions.

7.6 Relaxed network constraint limits

Previous chapters in this thesis have presented novel voltage control techniques and principles of access arrangement specific for wind farm connections at weak distribution networks. The strategy aim to effectively mitigate the voltage rise limitation problem to enhance wind connection capacities. However, where it is expected that renewable generation will continually contribute significantly to decarbonising electricity production, there is still a need to move away from the current strict network operation regime and regulation. This chapter explores the benefit of relaxing the network's constraint limits to enhance generation and promote greater wind farm development.

7.6.1 Relaxed voltage constraint limit

The Electricity Supply Regulation in the UK [151] stipulate that, unless otherwise agreed, the steady-state voltage of systems between 1 kV and 132 kV should be maintained within ±6% of the nominal. This is similar in other countries for example in Germany and the USA, where the operational voltages are set to vary up to ±5% of the nominal. However, DNOs in the UK have adopted a stringent and conservative approach to managing their networks and often require their 11 kV network voltages to be maintained within a permissible range of ±3% of the nominal [97]. This strict operation regime of the DNOs are implemented as precautionary measures to ensure a safe, secured and reliable operation of their network and also to demonstrate compliance with regulation.

In this section, we explore the potential to maximise distributed wind generation capacities by relaxing the current strict voltage limits placed on the secondary buses and allowing them to vary up to the maximum statutory limits of ±6% of the nominal. The test network is deployed in Matpower [122] simulation environment where a range of optimal power flow (OPF) simulations are performed. A suit of time-series OPF simulations are performed on the 11 kV network model where the secondary bus voltages are constrained and allowed to vary within a permissible range of ±3% , ±4% , ±5%, and ±6% configurations. The simulation studies are performed for a full year at half-hourly time-steps (17520 time-steps in total) to assess the impact on wind generation capacities. Figure 7.10 presents the benefit of potential wind energy production when the range of voltage constraint limits are implemented to connect and manage the wind farms.

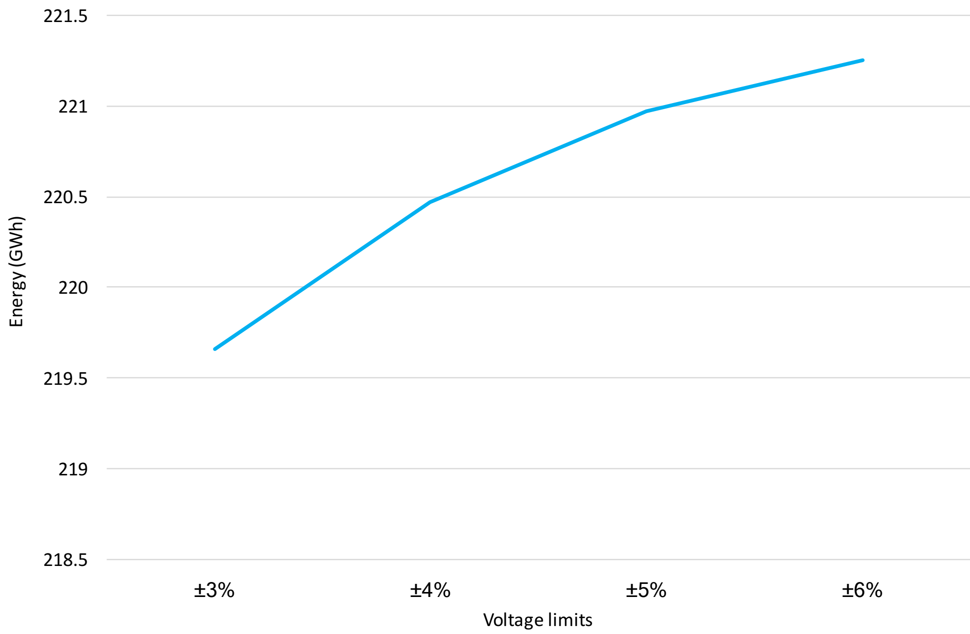


Figure 7.10: Wind generation capacities with changes in network voltage limits

From here it is observed that relaxing the secondary bus voltage limits enhances greater connection capacities as the DG voltage margins are raised, allowing greater active generations from the wind farms. Presently, the strict secondary bus voltage limit set at ±3% of the nominal to manage the DGs is seen to have significant impact on generation capacities of the wind farms. Future plans to expand the distribution network as DG penetration levels increase, will require pragmatic changes and a move away from the current strict operation principles to relaxed regime that encourages greater DG investment. DNOs operating ANM schemes can be encouraged to vary the voltage limits at the DG point of connections up to the statutory limits to allow greater headroom capacities for the non-firm generators. This however, will require proactive monitoring and control of the network and can be made possible through effective distribution management systems.

7.6.2 Relaxed power factor constraint limit

The UK Grid Code [23] requires wind farms to operate at a minimum power factor varying between 0.95 leading and 0.95 lagging of reactive power capability at the point of connection with the network. It has previously been established in Chapter 5 and 6 that voltage rise conditions occurring at the multiple DG locations at any given time-step can be controlled by employing intelligent switching between VC/RPD - PFC operational modes to mitigate the problem. The wind farms operating in variable power factor mode can actively adjust their power factors within the specified power factor and reactive power limits to control the voltage and maximise generation output. This section explores the potential to further enhance active power generation by relaxing the power factor constraint limit of the wind farms.

This section utilises the existing network model as seen in Figure 7.7. In this configuration, the DGs power factors are modelled to operate between 0.90 leading and 0.90 lagging limits. The secondary bus voltages are constrained at current DNO operational limits and allowed to vary within a permissible range of ±3% of the nominal. Figure 7.11 presents the benefits of energy generation levels when compared with minimum recommended power factor limits.

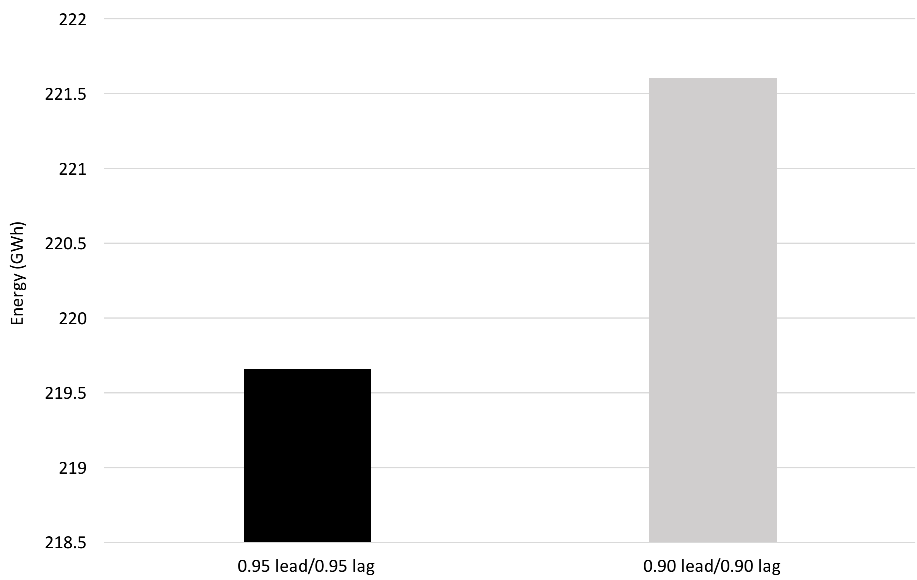


Figure 7.11: Total generation levels at relaxed power factor constraint limits

By comparing with the minimum 0.95 lead/lag DG power factor limits, it is observed that relaxing the power factor limits of the wind farms can enhance an efficient use of network capacity. Relaxing the power factor limits and allowing the wind farms to operate within a flexible power factor boundary offer potential benefit of minimising DG curtailment.

7.7 Overview of applied voltage control methods

A summary of the performance of the applied voltage control solutions when implemented on a representative 11 kV UK generic distribution case-study network is shown Figure 7.12. The presented strategy attempts to enhance wind farm connection capacities located at weak distribution networks at a minimum cost.

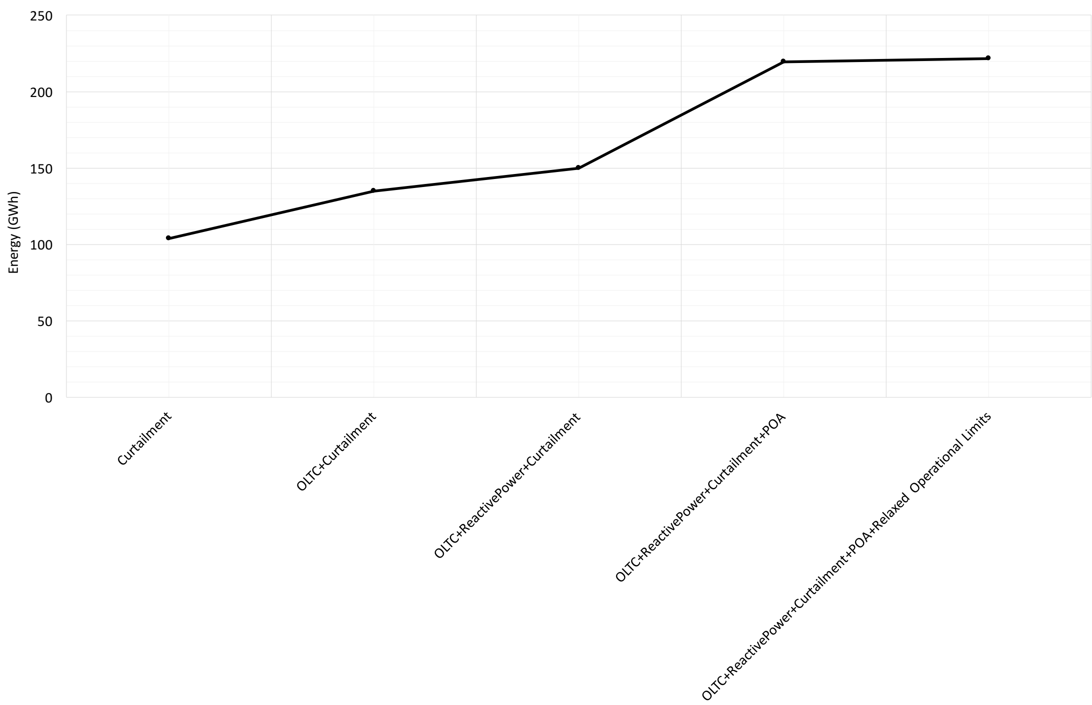


Figure 7.12: Performance summary of applied voltage control strategy

- The trend shows significant growth in wind energy levels as we systematically implement and move up the proposed voltage control hierarchy.
- Active power curtailment control action of the generators to address the voltage rise problem on its own offers the least economic benefit for the DG's including the overall energy yields.

- However, when curtailment is effectively coordinated with other ANM control solutions can offer greater connection capacities for the wind farms and maximise the overall wind energy output.

7.8 Summary

This section of the thesis has focused on validating and assessing the robustness and effectiveness of the proposed CVC and PoA strategy when applied under certain key changes in the network' s future operations. The key changes in network conditions investigated and most likely to occur included, future repowering opportunities for remotely connected wind farms, addition of future wind farm development at random locations on the network and further wind farm development at strong bus location with exiting wind farms. The studies undertaken quantified the benefit of the CVC and PoA to the wind farm generators when the changes in network conditions are implemented. The studies concludes that, the CVC control actions together with Enhanced Technical Best PoA arrangement provides the most economic benefit to the wind farms under all changes in future network conditions studied.

On the contrary, this arrangement may result to existing generators experiencing further curtailment (increasing the uncertainties for the DGs and future investment) as new non-firm generators connect onto the network. These issues will become prevalent for existing DGs connected at the weak sections of the network. Therefore to introduce fairness and attract greater DG investment, future planning operations may involve the DNO introducing a cap or guaranteeing a minimum generation level for all the DGs. In the case-study network presented in this thesis, a 20% minimum generation level is deemed as economically suitable. With the minimum generation cap serving as a baseline, the PoA methodology can then be applied to optimally allocate curtailment or share the network capacity.

This section has also presented alternative operational solutions that can be adopted to enhance wind farm generation capacities. The chapter has explored and demonstrated the benefit of implementing relaxed network operation constraint limits to manage DG connections.

The potential to maximise distributed wind generation capacities by relaxing the current strict voltage constraint limit and allowing them to vary up to the maximum statutory limit of $\pm 6\%$ of the nominal has been investigated. It was observed that relaxing the secondary bus voltage constraint limit enhances greater connection capacities as the DG voltage margins are raised, allowing greater active generations from the wind farms. Conversely, the benefit of relaxing the current power factor constraint limit and allowing the wind farms to operate within a flexible power factor boundary of 0.90 lead/lag can also minimise DG curtailment and maximise active power generation.

It is seen that, both proposed changes in network's operation constraint limits offers competitive benefit for the DNOs to accommodate greater wind farm connections as well as enhancing the economic viability for the DGs. These changes when considered, can potentially offer a cost-effective solution to distribution network management to accelerate greater renewable connections in timely manner.

Chapter 8

CONCLUSION

This chapter concludes the research presented and relates it to the research question and objectives defined in Chapter 1. It brings together and summarises the key learning outcomes and contributions that the thesis delivers and outlines possible future work. Each chapter presented in this thesis has contributed to the learning in the field of research and industry applications in the area of voltage management and principles of access (PoA) for wind farms connections at weak distribution networks. It provides discussions on the topic of coordinated voltage control (CVC) techniques and alternative commercial arrangements specific for wind farms connections managed under voltage constraint conditions. Each chapter of the thesis provides a perspective on the main thesis question.

This research has been motivated by the desire to increase the technical and economic viability of wind farm connections at weak distribution networks. It has presented methodologies that addresses many of the pertinent issues associated with the integration of DG connections. It recognises an active approach to network management as a key factor to maximising the economic and technical viability of DG connections. The necessity to move away from the previous fit and forget approach of passive networks towards an active network management is a step in the right direction and offers the benefit of greater controllability, monitoring, visibility and flexibility.

The proposed ANM solution develops a CVC strategy and PoA techniques that aim to mitigate the voltage rise problem. It adopts a hierarchical and systematic approach to implementing the control actions with the aim of maximising wind farm connection capacities at constrained distribution networks. This strategy leverages previous passive approach to distribution voltage management and introduces a coordination of current ANM technological solutions and PoA arrangement specific for voltage constrained active networks. The proposed strategy attempts to maximise DG connection capacities at a minimum cost and provides DNO's and wind farm owners, flexible control options that defers or avoids capital intensive network upgrades.

The framework presented in the earlier chapters (Chapter 3 to Chapter 5) extends and combines the formulation of the proposed ANM control actions. The development of an extensive multi-period OPF technique is used to assess the performance of the proposed solutions when applied to a representative UK generic distribution case-study network. The outcome of the study is presented in Chapter 6 and it shows that, significant growth in wind energy levels can be realised as we implement and move up the proposed voltage control hierarchy. It demonstrate the benefit to the wind generators when the ANM solutions and PoA are effectively coordinated.

The thesis defines and proposes new principles of access framework for multiple DWG connections managed under voltage constraint conditions. The newly proposed PoA regime is assessed under likely changes in future network operation conditions and scenarios in Chapter 7. These includes a quantitative assessment on generation levels and performance when the conditions are applied and it includes, re-powering opportunities for remotely connected DWGs, addition of further wind farm development and connections at random and strong bus locations with existing wind farms. The demonstration of the proposed strategy under the likely changes in the network's future operations provides a criteria to validate, assess and test the robustness of the newly defined PoAs when benchmarked with current DNO practice. It is observed from the case-studies that, CVC techniques with ETB principles of access arrangement provides the most economic benefit for connecting wind farms to weak distribution networks managed under voltage constraint conditions.

Likely changes in future network conditions includes the opportunity to maximise DG connection capacities through changes to current DNO operation constraint limits. Chapter 7 explores the potential to reduce DG curtailment by relaxing voltage constraint limits and adopting flexible power factor control regime. With the above mentioned points in place, this section of the thesis provides DNO's additional flexible options to consider and explore before finally reinforcing or upgrading their networks.

The ANM strategy presented in this thesis provides DNO's alternative solutions to network constraint management and flexible options to consider before reinforcing their network which can be costly and time consuming. It offers wind farm owners, flexible options to minimise excessive curtailment by controlling their voltage at the point of connection. It provides a guide for suitable location points of connections for future wind farm investment projects. It quantifies the risks and uncertainties associated with the different commercial arrangements. The developed coordinated voltage control and principles of access methods are relatively simple, safe, transparent and their operation can be quite easily understood. It conforms to the general requirements relating to ANM systems specified in Section 6.3. The presented methods are flexible in nature and can be adopted and reconfigured for future network operations.

8.1 Future work

8.1.1 Further analysis of the OLTC transformer tap operations

An optimised set-point voltage control technique of the AVC relay that controls the OLTC transformer have been modelled and presented in Chapter 3. The OPF technique was employed from a distribution network planning perspective to enhance the network hosting capacity to accommodate high penetration of wind generators. The optimised operating range of the AVC relay investigated provides the benefit and indicates a potential reduction in the number of tap changing operations of the OLTC transformer. Further work and an in-depth time-series load flow analysis is required in this area to fully model the operation of the tap changer controller when operated within the optimised operating range as demand and generation vary on the network.

The study can investigate and quantify the benefit to the OLTC transformer including reduced tap operations and extended life-span.

8.1.2 Integration of proposed ANM solutions with existing distribution management systems (DMS)

The proposed CVC and PoA approach to the voltage rise issue presented in Chapter 6 lays a foundation for DNOs and generators and provides flexible options on the methods that can be adopted to maximise DG connections at weak distribution networks. However, a full integration of the proposed techniques within an existing ANM scheme and DMS may require further investigation in this area. The exact practical implementation needs to be considered and some effort needs to be done. The embedded solutions may require real-time collection, monitoring and measurement of the state of the system and control devices through telecommunication links. Modern DMS equipped with full high-performance SCADA functionality can provide data acquisition, alarming, supervisory control, historical data collection. The newly developed solutions can be integrated into the existing program easily without affecting other functions and therefore the research in this area should be straight forward.

8.1.3 Exploration of fault-level constraint issues and PoA

Managing the distribution network with high penetration of intermittent generators characterised with significant fault level contributions is an emerging area in the field of research and industry applications. Quantifying fault level contribution from the wind farm generators, protection coordination and sharing limited network capacity among the multiple non-firm generators during a fault or network outage event is a challenge to network operators and recently gaining increased attention in academic research.

8.1.4 A comparative cost assessment of ANM technologies with network reinforcement

Active network management technologies and schemes have been a promising area to maximising DG integration and support for distribution system. While the costs of traditional reinforcements are widely available, the potential benefits and costs associated with ANM technologies and functions are equally quantifiable. ANM schemes are still at early stages and the costs are presently, tied up within incentive funding mechanisms. Several research works have been carried out to determine the cost and benefits of ANM schemes in an effort to justify the feasibility for developers joining the scheme. However, the benefit to the developers or customers are sometimes not clear or obvious. As ANM becomes a standard option for DNOs, a further study into the investment cost strategy would provide significant contribution to the research field. A methodology can then be developed to inform when DNOs should make the investment in traditional network assets, and when an ANM system would provide a suitable stop-gap to future reinforcements.

8.1.5 Investigating other smart grid technologies

An important research area mentioned in Chapter 2 of this thesis is the development and modelling of other smart grid technologies and techniques which are likely to be deployed in future network planning and operation. Dynamic line rating (DLR) is a technique that involves varying the thermal limit on the lines to take account of the prevailing environmental conditions. The technology involves squeezing more capacity out of existing network infrastructure through real-time monitoring. By measuring line parameters and weather conditions, DLR can determine the capacity of a section of the network at any given moment and use that information to help the network operate at peak performance.

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Appendix A

Generation and demand profiles

A.1 Normalised wind generation profile

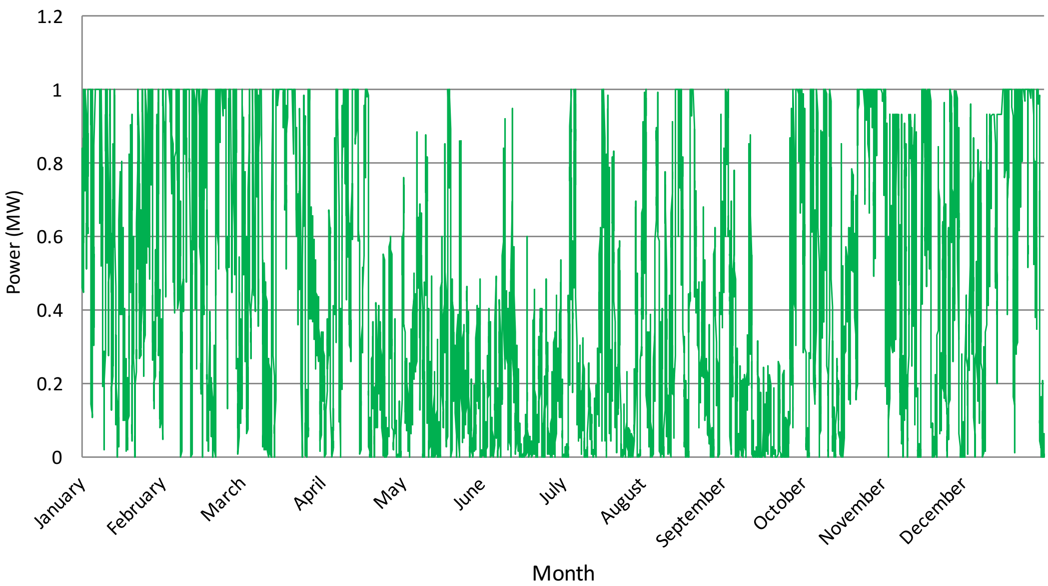

Figure A.1: Normalised wind profile - 1 year

A.2 Demand profile

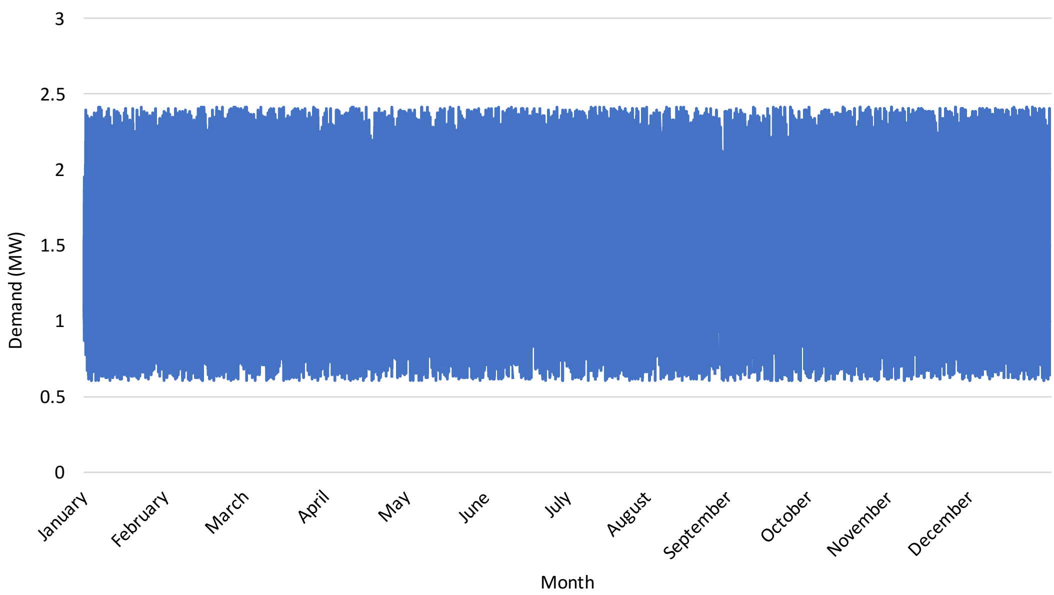

Figure A.2: Demand profile - 1 year

Appendix B

Chapter 3 summary of case-study results

B.1 LIFO PoA Results

Table B.1: LIFO principles of access

Priority Order	Generator	Dist. (km)	Capacity (MW)	Avail (MWh)	Non-firm (MWh)	Curtail (MWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
1	Gen A	1.1	10.0	2824.3	2824.3	0.00	100.0	0.0	30.0	30
2	Gen B	2.1	9.0	2541.9	2541.9	0.00	100.0	0.0	30.0	30
3	Gen C	3.3	7.6	2146.5	2146.5	0.00	100.0	0.0	30.0	30
4	Gen D	3.4	6.1	1722.8	1601.5	121.4	93.0	7.0	27.9	30
5	Gen E	7.2	4.1	1158.0	759.2	398.8	65.6	34.4	19.7	30
6	Gen F	16.4	3.4	960.3	526.6	433.7	54.8	45.2	16.5	30
7	Gen G	28.2	3.0	847.3	328.4	518.9	38.8	61.2	11.6	30
8	Gen H	34.2	2.3	649.6	154.6	495.0	23.8	76.2	7.1	30
		Total	45.5	12850.5	10882.8	1967.7	**84.7**	**15.3**	**25.4**	30

B.2 Reverse LIFO PoA Results

Table B.2: Reverse LIFO principles of access

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (MWh)	Non-firm (MWh)	Curtail (MWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
1	Gen H	34.2	2.3	649.6	588.2	61.4	90.5	9.5	27.2	30
2	Gen G	28.2	3.0	847.3	313.2	534.1	37.0	63.0	11.1	30
3	Gen F	16.4	3.4	960.3	224.4	735.8	23.4	76.6	7.0	30
4	Gen E	7.2	4.1	2824.3	809.3	2015.0	28.7	71.3	8.6	30
5	Gen D	3.4	6.1	1722.8	1286.9	435.9	74.7	25.3	22.4	30
6	Gen C	3.3	7.6	2541.9	875.6	1666.3	34.4	65.6	10.3	30
7	Gen B	2.1	9.0	1158.0	1047.6	110.4	90.5	9.5	27.1	30
8	Gen A	1.1	10.0	2146.5	488.0	1658.5	22.7	77.3	6.8	30
		Total	45.5	12850.5	5633.2	7217.3	**43.8**	**56.2**	**13.2**	30

B.3 Most Convenient PoA Results

Table B.3: Most convenient principles of access

Priority order	Gen erator	Dist. (km)	Capacity (MW)	Avail (MWh)	Non-firm (MWh)	Curtail (MWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
1	Gen C	3.3	7.6	2146.5	2146.5	0.0	100.0	0.0	30.0	30
2	Gen E	7.2	4.1	1158.0	1119.7	38.2	96.7	3.3	29.0	30
3	Gen B	12.7	9.0	2541.9	2253.5	288.3	88.7	11.3	26.6	30
4	Gen D	25.8	6.1	1722.8	1697.3	25.5	98.5	1.5	29.6	30
5	Gen A	35.8	10.0	2824.3	2680.3	144.0	94.9	5.1	28.5	30
6	Gen F	51.1	3.4	960.3	522.6	437.6	54.4	45.6	16.3	30
7	Gen G	63	3.0	847.3	324.1	523.2	38.3	61.7	11.5	30
8	Gen H	68.9	2.3	649.6	153.8	495.8	23.7	76.3	7.1	30
		Total	45.5	12850.5	10897.9	1952.6	**84.8**	**15.2**	**25.4**	30

B.4 Pro-Rata PoA Results

Table B.4: Pro - Rata principles of access

Priority order	Gen erator	Dist. (km)	Capacity (MW)	Avail (MWh)	Non-firm (MWh)	Curtail (MWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
1	Gen A	1.1	10.0	2824.3	426.8	2397.5	15.1	84.9	4.5	30
1	Gen B	2.1	9.0	2541.9	384.1	2157.7	15.1	84.9	4.5	30
1	Gen C	3.3	7.6	2146.5	324.4	1822.1	15.1	84.9	4.5	30
1	Gen D	3.4	6.1	1722.8	260.3	1462.5	15.1	84.9	4.5	30
1	Gen E	7.2	4.1	1158.0	175.0	983.0	15.1	84.9	4.5	30
1	Gen F	16.4	3.4	960.3	145.1	815.1	15.1	84.9	4.5	30
1	Gen G	28.2	3.0	847.3	128.0	719.2	15.1	84.9	4.5	30
1	Gen H	34.2	2.3	649.6	98.2	551.4	15.1	84.9	4.5	30
		Total	45.5	12850.5	1941.9	10908.6	**15.1**	**84.9**	**4.5**	30

B.5 Technical Best PoA Results

Table B.5: Technical Best principles of access

Priority order	Gen erator	Dist. (km)	Capacity (MW)	Avail (MWh)	Non-firm (MWh)	Curtail (MWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
1	Gen A	1.1	10.0	2824.3	2822.4	1.9	99.9	0.1	30.0	30
1	Gen B	2.1	9.0	2541.9	2540.6	1.3	100.0	0.0	30.0	30
1	Gen C	3.3	7.6	2146.5	2145.3	1.2	99.9	0.1	30.0	30
1	Gen D	3.4	6.1	1722.8	1599.3	123.5	92.8	7.2	27.8	30
1	Gen E	7.2	4.1	1158.0	1081.3	76.7	93.4	6.6	28.0	30
1	Gen F	16.4	3.4	960.3	720.6	239.7	75.0	25.0	22.5	30
1	Gen G	28.2	3.0	847.3	426.2	421.1	50.3	49.7	15.1	30
1	Gen H	34.2	2.3	649.6	235.9	413.7	36.3	63.7	10.9	30
		Total	45.5	12850.5	11571.7	1278.9	**90.0**	**10.0**	**27.0**	30

Appendix C

Chapter 5 summary of case-study results

C.1 Base-case scenario table of results

Table C.1: Summary of base-case scenario

Generator	Rated Capacity (MW)	Available energy (MWh)	Generated energy (MWh)	Curtailed energy (MWh)	Total Generation (%)	Total Curtailment (%)
Gen A	10.0	2824.3	2812.9	11.4	99.6	0.4
Gen B	9.0	2541.9	2531.1	10.8	99.6	0.4
Gen C	7.6	2146.5	2136.5	10.0	99.5	0.5
Gen D	6.1	1722.8	1353.0	369.8	78.5	21.5
Gen E	4.1	1158.0	858.8	299.2	74.2	25.8
Gen F	3.4	960.3	621.2	339.0	64.7	35.3
Gen G	3.0	847.3	361.2	486.1	42.6	57.4
Gen H	2.3	649.6	234.0	415.6	36.0	64.0
Total	45.5	12850.5	10908.6	1941.9	**84.9**	**15.1**

C.2 Constant PF (PF = 0.95 lag) table of results

Table C.2: Summary of results (PF= 0.95 lag)

Gen erator	Rated Capacity (MW)	Available energy (MWh)	Generated energy (MWh)	Curtailed energy (MWh)	Total Gen eration (%)	Total Cur- tailment (%)
Gen A	10	2824.3	2819.7	4.6	99.8	0.2
Gen B	9	2541.9	2535.3	6.6	99.7	0.3
Gen C	7.6	2146.5	2139.6	6.9	99.7	0.3
Gen D	6.1	1722.8	1326.2	396.6	77.0	23.0
Gen E	4.1	1158.0	849.4	308.6	73.4	26.6
Gen F	3.4	960.3	586.1	374.2	61.0	39.0
Gen G	3	847.3	321.2	526.1	37.9	62.1
Gen H	2.3	649.6	191.7	457.9	29.5	70.5
Total	45.5	12850.5	10769.1	2081.4	**83.8**	**16.2**

C.3 Constant PF (PF = 0.95 lead) table of results

Table C.3: Summary of results (PF = 0.95 lead)

Gen erator	Rated Capacity (MW)	Available energy (MWh)	Generated energy (MWh)	Curtailed energy (MWh)	Total Gen eration (%)	Total Cur- tailment (%)
Gen A	10.0	2824.3	2750.3	74.0	97.4	2.6
Gen B	9.0	2541.9	2431.9	110.0	95.7	4.3
Gen C	7.6	2146.5	2047.7	98.8	95.4	4.6
Gen D	6.1	1722.8	1440.4	282.4	83.6	16.4
Gen E	4.1	1158.0	973.4	184.5	84.1	15.9
Gen F	3.4	960.3	704.5	255.8	73.4	26.6
Gen G	3.0	847.3	430.2	417.1	50.8	49.2
Gen H	2.3	649.6	290.6	359.0	44.7	55.3
Total	45.5	12850.5	11068.9	1781.6	**86.1**	**13.92**

C.4 Variable PF ($0.98\ lead \leq PF \leq 0.95\ lag$) table of results

Table C.4: Summary of results ($0.98\ lead \leq PF \leq 0.95\ lag$)

Gen erator	Rated Capacity (MW)	Available energy (MWh)	Generated energy (MWh)	Curtailed energy (MWh)	Total Gen eration (%)	Total Curtailment (%)
Gen A	10.0	2824.3	2791.8	32.5	98.8	1.2
Gen B	9.0	2541.9	2508.9	33.0	98.7	1.3
Gen C	7.6	2146.5	2126.8	19.6	99.1	0.9
Gen D	6.1	1722.8	1324.5	398.3	76.9	23.1
Gen E	4.1	1158.0	842.7	315.3	72.8	27.2
Gen F	3.4	960.3	706.7	253.5	73.6	26.4
Gen G	3.0	847.3	447.7	399.6	52.8	47.2
Gen H	2.3	649.6	283.7	365.9	43.7	56.3
Total	45.5	12850.5	11032.8	1817.8	**85.9**	**14.1**

C.5 Variable PF ($0.95\ lead \leq PF \leq 0.95\ lag$) table of results

Table C.5: Summary of results ($0.95\ lead \leq PF \leq 0.95\ lag$)

Gen erator	Rated Capacity (MW)	Available energy (MWh)	Generated energy (MWh)	Curtailed energy (MWh)	Total Gen eration (%)	Total Curtailment (%)
Gen A	10.0	2824.3	2774.2	50.1	98.2	1.8
Gen B	9.0	2541.9	2474.1	67.7	97.3	2.7
Gen C	7.6	2146.5	2094.4	52.1	97.6	2.4
Gen D	6.1	1722.8	1348.2	374.7	78.3	21.7
Gen E	4.1	1158.0	847.5	310.5	73.2	26.8
Gen F	3.4	960.3	731.7	228.5	76.2	23.8
Gen G	3.0	847.3	519.4	327.9	61.3	38.7
Gen H	2.3	649.6	313.1	336.5	48.2	51.8
Total	45.5	12850.5	11102.6	1747.9	**86.4**	**13.6**

Appendix D

Chapter 6 summary of case-study results

D.1 Curtailment

Table D.1: Summary of Curtailment results

Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
Gen A	1.1	10.0	39.43	39.43	0.00	100.0	0.0	30.0	30
Gen B	2.1	9.0	35.48	30.26	5.23	85.3	14.7	25.6	30
Gen C	3.3	7.6	29.96	21.21	8.76	70.8	29.2	21.2	30
Gen D	3.4	6.1	24.05	4.19	19.86	17.4	82.6	5.2	30
Gen E	7.2	4.1	16.17	2.28	13.88	14.1	85.9	4.2	30
Gen F	16.4	3.4	13.41	2.74	10.66	20.5	79.5	6.1	30
Gen G	28.2	3.0	11.83	2.29	9.54	19.4	80.6	5.8	30
Gen H	34.2	2.3	9.07	1.49	7.57	16.5	83.5	4.9	30
	Total	45.5	179.39	103.89	75.51	**57.9**	**42.1**	17.4	30

D.2 On-load tap changer transformer (OLTC) + Curtailment

Table D.2: Summary of OLTC + Curtailment results

Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
Gen A	1.1	10.0	39.43	38.83	0.60	98.5	1.5	29.5	30
Gen B	2.1	9.0	35.48	33.80	1.69	95.2	4.8	28.6	30
Gen C	3.3	7.6	29.96	28.09	1.87	93.8	6.2	28.1	30
Gen D	3.4	6.1	24.05	12.70	11.35	52.8	47.2	15.8	30
Gen E	7.2	4.1	16.17	8.63	7.53	53.4	46.6	16.0	30
Gen F	16.4	3.4	13.41	6.62	6.78	49.4	50.6	14.8	30
Gen G	28.2	3.0	11.83	3.73	8.10	31.6	68.4	9.5	30
Gen H	34.2	2.3	9.07	2.66	6.41	29.4	70.6	8.8	30
	Total	45.5	179.39	135.06	44.33	**75.3**	**24.7**	22.6	30

D.3 On-load tap changer transformer (OLTC) + Reactive Power + Curtailment

Table D.3: Summary of OLTC + Reactive Power + Curtailment results

Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Uncurtail C.F (%)
Gen A	1.1	10.0	39.43	38.98	0.45	98.9	1.1	29.7	30
Gen B	2.1	9.0	35.48	35.09	0.39	98.9	1.1	29.7	30
Gen C	3.3	7.6	29.96	29.71	0.25	99.2	0.8	29.7	30
Gen D	3.4	6.1	24.05	17.73	6.32	73.7	26.3	22.1	30
Gen E	7.2	4.1	16.17	11.21	4.95	69.4	30.6	20.8	30
Gen F	16.4	3.4	13.41	9.02	4.39	67.3	32.7	20.2	30
Gen G	28.2	3.0	11.83	5.01	6.81	42.4	57.6	12.7	30
Gen H	34.2	2.3	9.07	3.04	6.03	33.5	66.5	10.0	30
	Total	45.5	179.39	149.79	29.60	**83.5**	**16.5**	25.0	30

D.4 CVC + LIFO table of results

Table D.4: Table of results CVC + LIFO PoA

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	39.43	0.00	99.99	0.01	30.00	1616500
2	Gen B	2.1	9.0	35.48	35.48	0.00	100.00	0.00	30.00	1454850
3	Gen C	3.3	7.6	29.96	16.45	13.51	54.90	45.10	16.47	674500
4	Gen D	3.4	6.1	24.05	8.32	15.73	34.58	65.42	10.37	340957
5	Gen E	7.2	4.1	16.17	4.41	11.76	27.26	72.74	8.18	180700
6	Gen F	16.4	3.4	13.41	3.17	10.24	23.63	76.37	7.09	129885
7	Gen G	28.2	3.0	11.83	2.51	9.32	21.19	78.81	6.36	102746
8	Gen H	34.2	2.3	9.07	1.73	7.34	19.10	80.90	5.73	71012
		Total	45.5	179.39	111.49	67.90	**62.15**	**37.85**	18.64	4571150

D.5 CVC + Reverse LIFO table of results

Table D.5: Table of results CVC + Reverse LIFO PoA

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen H	34.2	2.3	9.07	9.00	0.07	99.2	0.8	29.8	368943
2	Gen G	28.2	3.0	11.83	6.98	4.84	59.1	40.9	17.7	286367
3	Gen F	16.4	3.4	13.41	13.41	0.00	100.0	0.0	30.0	549610
4	Gen E	7.2	4.1	16.17	9.08	7.09	56.2	43.8	16.8	372228
5	Gen D	3.4	6.1	24.05	15.33	8.72	63.7	36.3	19.1	628395
6	Gen C	3.3	7.6	29.96	16.90	13.07	56.4	43.6	16.9	692824
7	Gen B	2.1	9.0	35.48	13.41	22.07	37.8	62.2	11.3	549824
8	Gen A	1.1	10.0	39.43	2.23	37.20	5.6	94.4	1.7	91324
		Total	45.5	179.39	86.33	93.06	**48.1**	**51.9**	14.4	3539515

D.6 CVC + Most Convenient table of results

Table D.6: Table of result CVC + Most convenient PoA

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen C	3.3	7.6	29.96	29.96	0.00	100.0	0.0	30.0	1228540
2	Gen E	7.2	4.1	16.17	16.16	0.00	100.0	0.0	30.0	662765
3	Gen B	2.1	9.0	35.48	32.95	2.53	92.9	7.1	27.9	1351144
4	Gen D	3.4	6.1	24.05	10.81	13.24	45.0	55.0	13.5	443377
5	Gen A	1.1	10.0	39.43	12.14	27.29	30.8	69.2	9.2	497757
6	Gen F	16.4	3.4	13.41	3.17	10.24	23.6	76.4	7.1	129885
7	Gen G	28.2	3.0	11.83	2.51	9.32	21.2	78.8	6.4	102746
8	Gen H	34.2	2.3	9.07	1.73	7.34	19.1	80.9	5.7	71012
		Total	45.5	179.39	109.44	69.95	**61.0**	**39.0**	18.3	4487225

D.7 CVC + Pro-Rata table of results

Table D.7: Table of results CVC + Pro-Rata PoA

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	6.19	33.24	15.7	84.3	4.7	253791
1	Gen B	2.1	9.0	35.48	5.57	29.91	15.7	84.3	4.7	228411
1	Gen C	3.3	7.6	29.96	4.70	25.26	15.7	84.3	4.7	192881
1	Gen D	3.4	6.1	24.05	3.78	20.27	15.7	84.3	4.7	154812
1	Gen E	7.2	4.1	16.17	2.54	13.63	15.7	84.3	4.7	104054
1	Gen F	16.4	3.4	13.41	2.10	11.30	15.7	84.3	4.7	86289
1	Gen G	28.2	3.0	11.83	1.86	9.97	15.7	84.3	4.7	76137
1	Gen H	34.2	2.3	9.07	1.42	7.64	15.7	84.3	4.7	58372
		Total	45.5	179.39	28.16	151.23	**15.7**	**84.3**	4.7	1154747

D.8 CVC + Enhanced Technical Best table of results

Table D.8: Table of results CVC + Enhanced Technical Best

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	39.08	0.34	99.1	0.9	29.7	1602417
1	Gen B	2.1	9.0	35.48	35.02	0.46	98.7	1.3	29.6	1435925
1	Gen C	3.3	7.6	29.96	29.70	0.27	99.1	0.9	29.7	1217563
1	Gen D	3.4	6.1	24.05	22.46	1.59	93.4	6.6	28.0	920980
1	Gen E	7.2	4.1	16.17	14.57	1.59	90.1	9.9	27.0	597451
1	Gen F	16.4	3.4	13.41	11.52	1.89	85.9	14.1	25.8	472275
1	Gen G	28.2	3.0	11.83	6.94	4.89	58.7	41.3	17.6	284608
1	Gen H	34.2	2.3	9.07	4.01	5.06	44.2	55.8	13.3	164408
		Total	45.5	179.39	163.31	16.08	**91.0**	**9.0**	27.3	6695625

Appendix E

Chapter 7 summary of case-study results

E.1 LIFO PoA under repowering opportunities

Table E.1: LIFO PoA under repowering opportunities

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	39.43	0.00	100.0	0.0	30.0	1616500
2	Gen B	2.1	9.0	35.48	35.48	0.00	100.0	0.0	30.0	1454850
3	Gen C	3.3	7.6	29.96	16.45	13.51	54.9	45.1	16.5	674500
4	Gen D	3.4	6.1	24.05	8.32	15.73	34.6	65.4	10.4	340957
5	Gen E1	7.2	4.4	17.35	4.70	12.65	27.1	72.9	8.1	192774
6	Gen F1	16.4	5.0	19.71	4.49	15.23	22.8	77.2	6.8	183958
7	Gen G1	28.2	4.0	15.77	3.05	12.72	19.4	80.6	5.8	125204
8	Gen H1	34.2	3.3	13.01	2.05	10.97	15.7	84.3	4.7	83846
		Total	49.4	194.77	113.97	80.80	**58.5**	**41.5**	17.6	4672590

E.2 Most Convenient PoA under repowering opportunities

Table E.2: Most Convenient PoA under repowering opportunities

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen C	3.3	7.6	29.96	29.96	0.00	100.0	0.0	30.0	1228540
2	Gen E1	7.2	4.4	17.35	17.35	0.00	100.0	0.0	30.0	711260
3	Gen B	2.1	9.0	35.48	32.33	3.15	91.1	8.9	27.3	1325669
4	Gen D	3.4	6.1	24.05	10.61	13.44	44.1	55.9	13.2	434942
5	Gen A	1.1	10.0	39.43	11.97	27.46	30.4	69.6	9.1	490788
6	Gen F1	16.4	5.0	19.71	4.49	15.23	22.8	77.2	6.8	183959
7	Gen G1	28.2	4.0	15.77	3.05	12.72	19.4	80.6	5.8	125205
8	Gen H1	34.2	3.3	13.01	2.05	10.97	15.7	84.3	4.7	83846
		Total	49.4	194.77	111.81	82.96	**57.4**	**42.6**	17.2	4584208

E.3 Enhanced Technical Best PoA under repowering opportunities

Table E.3: Enhanced Technical Best PoA under repowering opportunities

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	39.03	0.40	99.0	1.0	29.7	1600091
1	Gen B	2.1	9.0	35.48	34.94	0.55	98.5	1.5	29.5	1432503
1	Gen C	3.3	7.6	29.96	29.60	0.36	98.8	1.2	29.6	1213658
1	Gen D	3.4	6.1	24.05	21.70	2.36	90.2	9.8	27.1	889507
1	Gen E1	7.2	4.4	17.35	14.88	2.47	85.8	14.2	25.7	610159
1	Gen F1	16.4	5.0	19.71	13.41	6.31	68.0	32.0	20.4	549610
1	Gen G1	28.2	4.0	15.77	8.39	7.38	53.2	46.8	16.0	344113
1	Gen H1	34.2	3.3	13.01	4.86	8.15	37.4	62.6	11.2	199367
		Total	49.4	194.77	166.81	27.96	**85.6**	**14.4**	25.7	6839007

E.4 LIFO PoA under additional wind farm development at random bus location

Table E.4: LIFO PoA under additional wind farm development at random bus location

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	39.43	0.00	100.0	0.0	30.0	1616500
2	Gen B	2.1	9.0	35.48	35.48	0.00	100.0	0.0	30.0	1454850
3	Gen C	3.3	7.6	29.96	16.45	13.51	54.9	45.1	16.5	674500
4	Gen D	3.4	6.1	24.05	8.32	15.73	34.6	65.4	10.4	340957
5	Gen E1	7.2	4.4	17.35	4.70	12.65	27.1	72.9	8.1	192774
6	Gen F1	16.4	5.0	19.71	4.49	15.23	22.8	77.2	6.8	183958
7	Gen G1	28.2	4.0	15.77	3.05	12.72	19.4	80.6	5.8	125204
8	Gen H1	34.2	3.3	13.01	2.05	10.97	15.7	84.3	4.7	83846
9	Gen I	3.7	5.7	22.47	3.27	19.21	14.5	85.5	4.4	133960
10	Gen J	10.5	2.5	9.86	1.27	8.58	12.9	87.1	3.9	52242
11	Gen K	13.2	8.5	33.51	3.19	30.32	9.5	90.5	2.9	130933
12	Gen L	32.13	3.7	14.6	1.01	13.58	6.9	93.1	2.1	41530
		Total	69.8	275.20	122.71	152.49	**44.6**	**55.4**	13.4	5031254

E.5 MC PoA under additional wind farm development at random bus locations

Table E.5: MC PoA under additional wind farm development at random bus locations

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen C	3.3	7.6	29.96	29.96	0.00	100.0	0.0	30.0	1228540
2	Gen E1	7.2	4.4	17.35	17.35	0.00	100.0	0.0	30.0	711260
3	Gen B	2.1	9.0	35.48	32.33	3.15	91.1	8.9	27.3	1325669
4	Gen D	3.4	6.1	24.05	10.61	13.44	44.1	55.9	13.2	434942
5	Gen A	1.1	10.0	39.43	11.97	27.46	30.4	69.6	9.1	490788
6	Gen F1	16.4	5.0	19.71	4.49	15.23	22.8	77.2	6.8	183959
7	Gen G1	28.2	4.0	15.77	3.05	12.72	19.4	80.6	5.8	125205
8	Gen H1	34.2	3.3	13.01	2.05	10.97	15.7	84.3	4.7	83846
9	Gen J	10.5	2.5	9.86	2.98	6.88	30.2	69.8	9.1	122129
10	Gen I	3.7	5.7	22.47	3.19	19.29	14.2	85.8	4.3	130645
11	Gen K	13.2	8.5	33.51	3.31	30.20	9.9	90.1	3.0	135782
12	Gen L	32.13	3.7	14.6	1.02	13.57	7.0	93.0	2.1	41802
		Total	69.8	275.20	122.31	152.89	**44.4**	**55.6**	13.3	5014565

E.6 ETB PoA under additional wind farm development at random bus locations

Table E.6: ETB PoA under additional wind farm development at random bus locations

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	38.28	1.15	97.1	2.9	29.1	1569408
1	Gen B	2.1	9.0	35.48	33.95	1.53	95.7	4.3	28.7	1392102
1	Gen C	3.3	7.6	29.96	28.62	1.34	95.5	4.5	28.7	1173455
1	Gen D	3.4	6.1	24.05	18.78	5.27	78.1	21.9	23.4	770011
1	Gen E1	7.2	4.4	17.35	11.77	5.58	67.8	32.2	20.3	482461
1	Gen F1	16.4	5.0	19.71	7.67	12.04	38.9	61.1	11.7	314624
1	Gen G1	28.2	4.0	15.77	5.04	10.73	32.0	68.0	9.6	206641
1	Gen H1	34.2	3.3	13.01	3.59	9.42	27.6	72.4	8.3	147021
1	Gen I	3.7	5.7	22.47	10.65	11.83	47.4	52.6	14.2	436550
1	Gen J	10.5	2.5	9.86	5.69	4.16	57.8	42.2	17.3	233488
1	Gen K	13.2	8.5	33.51	25.61	7.90	76.4	23.6	22.9	1050013
1	Gen L	32.13	3.7	14.6	3.62	10.97	24.8	75.2	7.4	148480
		Total	69.8	275.20	193.27	47.07	**70.2**	**17.1**	21.1	7924254

E.7 LIFO PoA under additional wind farm development at same bus location

Table E.7: LIFO PoA under additional wind farm development at strong bus location

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	39.43	0.00	100.0	0.0	30.0	1616500
2	Gen B	2.1	9.0	35.48	35.48	0.00	100.0	0.0	30.0	1454850
3	Gen C	3.3	7.6	29.96	16.45	13.51	54.9	45.1	16.5	674500
4	Gen D	3.4	6.1	24.05	8.32	15.73	34.6	65.4	10.4	340957
5	Gen E1	7.2	4.4	17.35	4.70	12.65	27.1	72.9	8.1	192774
6	Gen F1	16.4	5.0	19.71	4.49	15.23	22.8	77.2	6.8	183958
7	Gen G1	28.2	4.0	15.77	3.05	12.72	19.4	80.6	5.8	125204
8	Gen H1	34.2	3.3	13.01	2.05	10.97	15.7	84.3	4.7	83846
9	Gen I	3.7	5.7	22.47	3.27	19.21	14.5	85.5	4.4	133960
10	Gen J	10.5	2.5	9.86	1.27	8.58	12.9	87.1	3.9	52242
11	Gen K	13.2	8.5	33.51	3.19	30.32	9.5	90.5	2.9	130933
12	Gen L	32.13	3.7	14.6	1.01	13.58	6.9	93.1	2.1	41530
13	Gen M	1.1	9.5	37.5	2.12	35.33	5.7	94.3	1.7	87019
14	Gen N	2.1	8.8	34.7	2.10	32.59	6.1	93.9	1.8	86266
15	Gen O	3.3	7.0	27.6	1.49	26.11	5.4	94.6	1.6	60912
16	Gen P	3.4	6.5	25.6	1.28	24.34	5.0	95.0	1.5	52664
		Total	101.6	400.58	129.71	270.87	**32.4**	**67.6**	9.7	5318115

E.8 MC PoA under additional wind farm development at same bus locations

Table E.8: MC PoA under additional wind farm development at strong bus locations

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen C	3.3	7.6	29.96	29.96	0.00	100.0	0.0	30.0	1228540
2	Gen E1	7.2	4.4	17.35	17.35	0.00	100.0	0.0	30.0	711260
3	Gen B	2.1	9.0	35.48	32.33	3.15	91.1	8.9	27.3	1325669
4	Gen D	3.4	6.1	24.05	10.61	13.44	44.1	55.9	13.2	434942
5	Gen A	1.1	10.0	39.43	11.97	27.46	30.4	69.6	9.1	490788
6	Gen F1	16.4	5.0	19.71	4.49	15.23	22.8	77.2	6.8	183959
7	Gen G1	28.2	4.0	15.77	3.05	12.72	19.4	80.6	5.8	125205
8	Gen H1	34.2	3.3	13.01	2.05	10.97	15.7	84.3	4.7	83846
9	Gen J	10.5	2.5	22.47	3.19	19.29	14.2	85.8	4.3	130645
10	Gen I	3.7	5.7	9.86	2.98	6.88	30.2	69.8	9.1	122129
11	Gen K	13.2	8.5	33.51	3.31	30.20	9.9	90.1	3.0	135782
12	Gen L	32.13	3.7	14.6	1.02	13.57	7.0	93.0	2.1	41802
13	Gen O	3.30	7.0	27.6	1.53	26.07	5.5	94.5	1.7	62697
14	Gen N	2.1	8.8	34.7	1.89	32.80	5.5	94.5	1.6	77586
15	Gen P	3.4	6.5	25.6	1.66	23.96	6.5	93.5	1.9	68212
16	Gen M	1.1	9.5	37.5	1.74	35.72	4.6	95.4	1.4	71244
		Total	101.6	400.58	129.13	271.45	**32.2**	**67.8**	9.7	5294304

E.9 ETB PoA under additional wind farm development at strong bus location

Table E.9: ETB PoA under additional wind farm development at same bus locations

Priority Order	Gen erator	Dist. (km)	Capacity (MW)	Avail (GWh)	Non-firm (GWh)	Curtail (GWh)	Gen (%)	Curtail (%)	C.F (%)	Indicative Revenue(£/yr)
1	Gen A	1.1	10.0	39.43	33.96	5.46	86.1	13.9	25.8	1392509
1	Gen B	2.1	9.0	35.48	25.43	10.05	71.7	28.3	21.5	1042638
1	Gen C	3.3	7.6	29.96	19.51	10.45	65.1	34.9	19.5	800064
1	Gen D	3.4	6.1	24.05	9.52	14.53	39.6	60.4	11.9	390231
1	Gen E1	7.2	4.4	17.35	6.64	10.70	38.3	61.7	11.5	272365
1	Gen F1	16.4	5.0	19.71	6.20	13.52	31.4	68.6	9.4	254120
1	Gen G1	28.2	4.0	15.77	4.16	11.61	26.4	73.6	7.9	170433
1	Gen H1	34.2	3.3	13.01	2.92	10.09	22.5	77.5	6.7	119826
1	Gen I	3.7	5.7	22.47	6.86	15.61	30.5	69.5	9.2	281250
1	Gen J	10.5	2.5	9.86	3.78	6.08	38.4	61.6	11.5	154988
1	Gen K	13.2	8.5	33.51	13.78	19.73	41.1	58.9	12.3	565112
1	Gen L	32.13	3.7	14.6	3.30	11.29	22.6	77.4	6.8	135328
1	Gen M	1.1	9.5	37.5	32.16	5.29	85.9	14.1	25.8	1318627
1	Gen N	2.1	8.8	34.7	24.82	9.87	71.5	28.5	21.5	1017659
1	Gen O	3.3	7.0	27.6	17.90	9.70	64.9	35.1	19.5	733929
1	Gen P	3.4	6.5	25.6	8.71	16.92	34.0	66.0	10.2	356964
		Total	101.6	400.58	219.66	180.92	**54.8**	**45.2**	16.5	9006042