DEPARTMENT OF ELECTRONIC & ELECTRICAL ENGINEERING

University of Strathclyde Engineering

An Assessment of Power System Principles of Access for Wind Power Using Optimal Power Flow

By

Laura Kane

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

Doctor of Philosophy

2015

Declaration

'This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.'

Signed:

Date:

For Ade

"I hope that you're folding stars."

Acknowledgements

I would like to thank Graham Ault for providing me with guidance, knowledge and advice. Thanks to Keith Bell, Graeme Hawker and other members of IEE who have provided me with support and challenging discussion during my time within the department.

To the EPRSC and the staff & students of the Wind Energy CDT who have provided me with the opportunity to undertake this research, a fantastic environment to work in and of course, support from my fellow researchers and friends. In particular, a special thank you to Simon Gill who was always willing to discuss the finer details of electricity markets, and Drew Smith for always being the man in the know.

Thank you to SSE, UKPN and Smarter Grid Solutions for providing me with opportunities to work with, and engage with them during my research.

Finally, thank you to my friends and family, and especially to Cal for all your support and encouragement.

Contents

List of Figures

List of Tables

Abstract

The growth of renewable generation (and wind generation in particular) in distribution networks is leading to the development of Active Network Management (ANM) strategies and solutions. ANM systems aim to increase the capacity of renewable and distributed generation that can connect to power networks. One such ANM strategy is generation curtailment where distributed generation is given a non-firm connection under which the network operator instructs the generator to reduce its power output under specified conditions and this is practically achieved through the implementation of automatic controls in the ANM system. The rules which define the method of curtailment are often referred to as Principles of Access (PoA).

The UK is currently at the forefront of ANM research and there are a number of full scale trials in Orkney [1], Shetland [2] and Cambridgeshire [3]. All of these schemes will apply PoA for curtailment of wind generators. There has been little research undertaken to date on alternative PoA for non-firm wind generation other than those implemented in these trial schemes.

This research performs a qualitative analysis of PoA using industry recognised assessment criteria, and a quantitative analysis of PoA using an Optimal Power Flow (OPF) method. Business models present a means of recovering the costs of ANM and compares this to the cost of traditional methods of network reinforcement.

Alternative PoA can have a significant impact on the capacity factor of generators and a PoA which implements a market system is found to deliver the best result for both network and generator. Alternatively, PoA which distribute curtailment more evenly across generators such as Pro Rata provide an increase in capacity factor for generators lower in the priority stack under a LIFO arrangement.

Abbreviations

ANM	Active Network Management
BaU	Business as Usual
BM	Balancing Mechanism
BSUoS	Balancing Services Use of System
CF	Capacity Factor
CfD	Contract for Difference
CMCP	Curtailment Market Clearing Price
DECC	Department of Energy and Climate Change
DNO	Distribution Network Operator
DNUoS	Distribution Network Use of System
DSO	Distribution System Operator
EMR	Electricity Market Reform
FITs	Feed-in Tariff
GSP	Grid Supply Point
HH	Half-Hourly
LIFO	Last in First off
NFG	Non-Firm Generation
NHH	Non-Half-Hourly
O&M	Operation and Maintenance
Ofgem	Office of Gas and Electricity Markets
PAB	Pay-as-Bid
PoA	Principles of Access
PPA	Power Purchase Agreement
ROCs	Renewable Obligation Certificates
SEMO	Single Electricity Market Operator (Irish electricity system operator)
SO	System Operator
TNO	Transmission Network Operator
TNUoS	Transmission Network Use of System
TSO	Transmission System Operator
UoS	Use of System

1 Introduction

1.1 The Growth of the Smart Grid

In the last ten years, the increase in the use of renewable generation has led to a shift in the way the electricity system operates in the UK. Carbon reduction targets, subsidies and renewable energy targets have all contributed towards this shift. The GB electricity system is no longer dominated by large decentralised coal and gas generators and instead has increased the number of renewable generation, and in particular, the number of wind generators connected to the system. At lower voltage levels, the number of distributed generators has also increased. Many distribution networks now contain generators distributed within the network resulting in more energy being utilised at lower voltage levels to meet local demand, and reduce the amount of energy which is drawn from transmission level.

The growth of the 'smart grid' has been a natural progression from the increase in distributed generation. The distribution network is moving away from being a passively managed system with energy flowing from high voltage levels down to households, towards being more 'actively' managed in an approach similar to that at transmission level.

The growth of smart grids can be reflected by the number of research articles published in recent years. The growth in IEEE journal publications with 'Smart Grid' in the title is demonstrated by the graph in Figure 1-1. There was a sharp increase in publications between 2009 and 2010 which could be related to the launch of the Low Carbon Network Fund by Ofgem in 2009 [4]. This fund was created to encourage innovation from DNOs and a number of projects include partners in research institutions. Since 2009, there has been a steady increase in the number of research groups and new technology developed as part of network innovation and the regulator is now encouraging DNOs to take this innovation forward as part of normal business procedures.

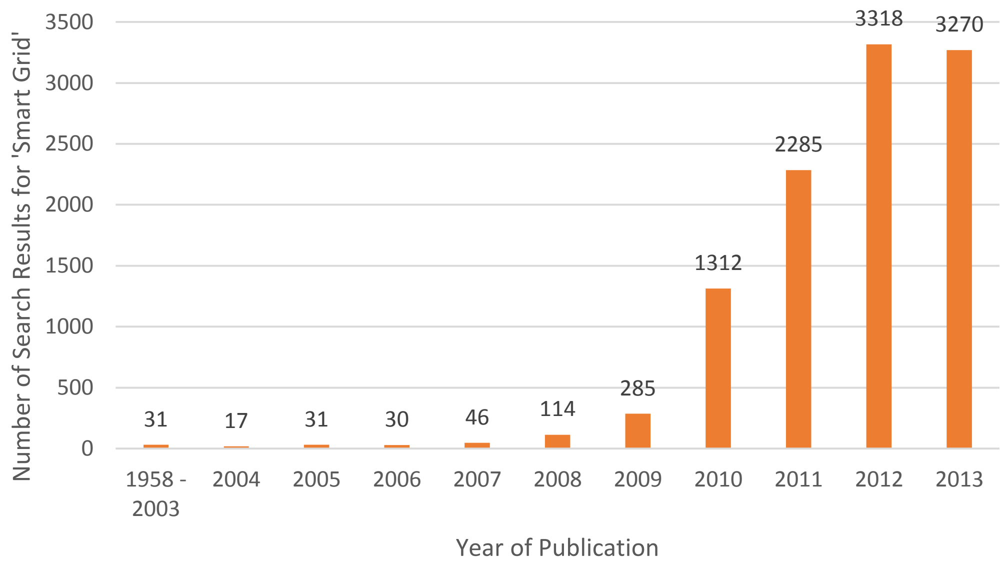

Figure 1-1 Growth of IEEE journal publications that are returned when 'Smart Grid' is searched for

As a result of the drive to connect more renewables to the UK electricity system, there has been an increase in system constraints. The transmission network already has systems in place to manage these constraints [5] however new methods to manage generation and constraints at distribution level had to be developed.

Active Network Management (ANM) is the distribution network management concept that allows DNOs to manage the network in a similar manner to transmission. In this thesis, ANM is defined as the control of power, voltage and frequency within a network through the use of remote control and communication technologies. ANM provides an alternative to investing in traditional network upgrades or the installation of traditional power system equipment such as capacitor banks, or new transformers. Using ANM, DNOs can make better use of the existing network capacity through active control of connected wind generation and other resources.

Other names for ANM systems include Actively Managed Distribution systems, Active Distribution Networks, Smart Grids, Flexible Networks, Distributed Energy Resources Management or Control, Flexible Connections, and Intelligent Networks although ANM is now starting to be used in a much more specific way and so not entirely synonymous with these other terms

The range of controls used in ANM systems vary depending on the network issues related to each case. A Cigre report published in 2011 [6] carried out a survey and provided a number of definitions regarding ANM systems. A list of some of the main features, applications and benefits of ANM systems is given in Table 1-1 below.

Table 1-1 Main features of ANM Systems [6]

Features	Applications	Benefits
• Protection • Communication • Integration into existing systems • Flexible network topology • ANM capable equipment • Smart metering technologies	• Power flow congestion management • Data collection and management • Voltage management • Distributed generation and load control • Fast Reconfiguration	• Improved reliability • Increased asset utilisation • Improved assess for DG • Alternative to network reinforcement • Network stability • Improved network efficiency (loss reduction)

One of the key issues for distribution networks is the thermal capacity of network branches. Lack of thermal capacity can play a significant role in the delay to connect renewable generation to the network. By using ANM systems, the power flow on the network branches can be managed via control instructions that are sent to generators to trip, or trim generation when lines become over loaded. For example, during periods of high wind and low demand, a wind generator connected to the ANM scheme may be asked to decrease the export to the network. This is often referred to as curtailment and this is a common feature of the early ANM trial projects. This thesis explores specific aspects of the ANM domain, namely the rules that determine which generators are curtailed and when.

The growth of actively managed distribution systems in recent years has led to a requirement to define new rules and operational procedures for DNOs and this work aims to do this by focusing on the rules regarding curtailment of generation and by addressing additional commercial aspects of ANM.

1.2 Principles of Access

In order to manage the constraints, and the related curtailment at distribution level, new rules are required to inform generators connected to the scheme of the curtailment management system. These are often referred to as ‘Principles of Access’. They define the rules and relationships between all users (i.e. generators and demand) of the ANM system and the available, through constrained network capacity or headroom.

Generators that connect to an ANM scheme will be aware of the risk of curtailment in advance. These generators will be awarded non-firm connections. This compares with firm connections who have the right to generate regardless of levels of output of demand based on N-1 or other relevant security standards. Non-firm generation will be allowed to output energy to the network when there is space available. This flexible connection arrangement allows generators to connect when they may not have been able to, prior to lengthy waiting periods and expensive network reinforcements.

The diagrams in Figure 1-2 and Figure 1-3 help to demonstrate the application of firm and non-firm generation on a constrained network. In Figure 1-2, the network is at maximum capacity due to N-1 security limits. During an outage on one of the conductors, the maximum capacity is 20 MW, therefore the maximum allowable firm wind connection is 22 MW given that the minimum demand is 2 MW.

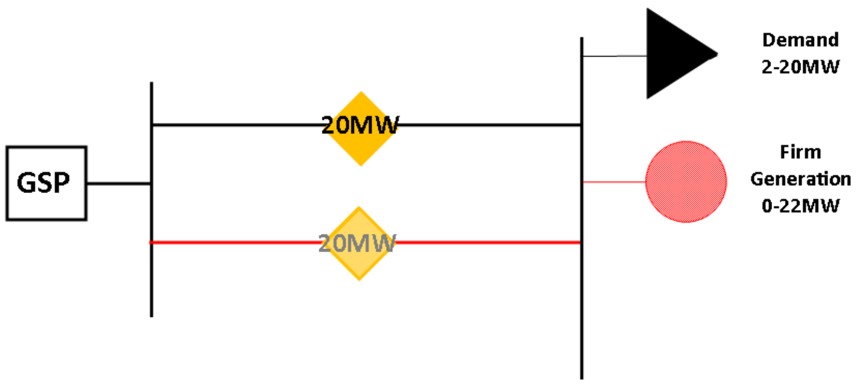

Figure 1-2 Schematic showing firm network capacity under N-1 conditions

By utilising ANM techniques, non-firm generation can be connected. The available capacity for non-firm generation is calculated as follows:

$$\begin{aligned}&\mathit{Non\ Firm\ Capacity}\\&\qquad\qquad = \mathit{Network\ Thermal\ Capacity} + \mathit{Maximum\ Demand}\\&\qquad\qquad - \mathit{Maximum\ Firm\ Generation}\end{aligned}$$

This additional capacity available through ANM control is demonstrated by the network schematic in Figure 1-3.

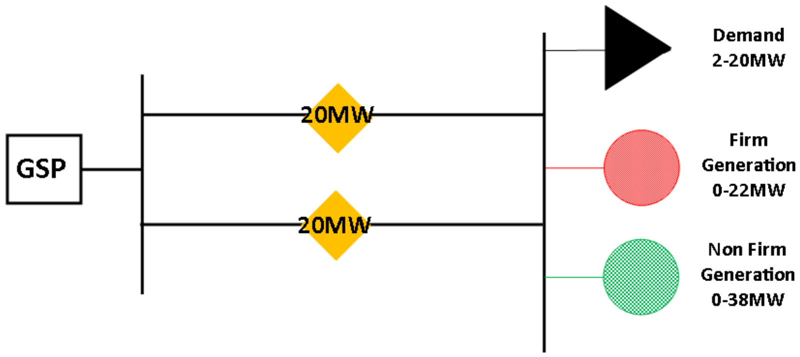

Figure 1-3 Schematic showing firm and non-firm capacity by utilising ANM control systems

As the number of ANM schemes increase in the UK, and the growth of distribution generation increases, the management of generation at distribution level also grows in importance. Initially PoA will be used to manage the tripping and trimming of generation in constrained networks, however in the next few decades to come as the level of distribution connection generation increases, this could expand into a wider system balancing and interaction with processes at transmission level. There is a requirement to investigate PoA and explore where trials and demonstrations of different methods could benefit future system operation. The majority of existing ANM Schemes have applied a Last In First Off (LIFO) PoA [7], [8] where the last generator to connect to the network will be the first generator to curtail during a constrained period. While this is an entirely acceptable method for curtailing generation, there is a requirement to fully explore alternative PoA. A number of papers and projects have discussed PoA to date [9], [10] however there has been no research published which explores alternative PoA using a thorough quantitative approach.

1.3 Thesis Focus

The focus of this thesis is on the investigation of alternative PoA through the use of both qualitative and quantitative analysis. A ‘Last in First Off’ PoA has been adopted by the majority of the existing and planned ANM schemes in the UK to date and this thesis will focus on the Orkney ANM scheme in particular. A qualitative analysis will look at alternative PoA for further quantitative analysis and will identify a number of policy and business implications related to each PoA. The selected PoA will then be subjected to a quantitative analysis using a case study network. The case study used is based on the Orkney distribution network and operational ANM scheme [11] and the analysis will focus on thermal constraints and non-firm wind generation.

1.4 Research Objectives

The main question that this work intends to address is:

> **Are there suitable alternatives to LIFO for non-firm wind generators connected to Active Network Management schemes?**

Answering this question requires the development of both qualitative and quantitative analysis techniques which will compare the impact of alternative PoA on the output of non-firm wind generators connected to an ANM scheme. These methods will be applied to a case study based on the Orkney ANM scheme.

Thus, the objectives of this thesis are defined below:

- Review existing literature on ANM and active distribution networks and establish the current application of PoA to non-firm wind generators.
- Identify a suitable list of assessment criteria against which PoA can be benchmarked.
- Review existing PoA and identify possible alternatives for renewable generators connected to ANM schemes through qualitative analysis.
- Develop a suitable curtailment market model for application at distribution level.
- Review the methods of modelling power flows in distribution networks and identify a suitable methodology for analysing PoA.
- Develop an Optimal Power Flow (OPF) framework suitable for modelling the impact of PoA on non-firm wind generation.
- Model the effects PoA have on the capacity factor of wind generators when compared with the current LIFO arrangements through quantitative analysis.

- Review the current method of cost recovery for traditional network reinforcements and identify a method for recouping the costs of ANM schemes.
- Develop a business model which will outline the main stakeholders involved in ANM schemes and demonstrate the flow of goods and services between the relevant stakeholders.
- Identify the impact that the growth of ANM may have on wider system operation in the future.

The use of a qualitative assessment will identify which PoA are most suitable for further study using a quantitative assessment. The use of an OPF method will ensure that network characteristics are accounted for in the curtailment evaluation, and that security limits are adhered to at all times. Comparison of capacity factors gives an indication of severity of curtailment, and in doing so, gives an indication of the revenue impact on curtailed generators. Finally, the comparison between traditional reinforcement costs and the cost of ANM systems uses a visualisation technique to demonstrate the flow of goods and services between actors in the electricity industry. This is a novel technique to present ways in which DNOs may recover the costs of ANM schemes in the future, when they are no longer funded through network innovation funds.

1.5 Principal Contributions

This thesis delivers a number of important contributions to power systems in terms of both knowledge and novel techniques. In particular, this work contributes to the field of distribution networks, renewable integration and smart grid research.

Provide further definition of Principles of Access

The application of curtailment management strategies is a fairly new research area. This work aims to identify the key questions and issues associated with PoA. While this work focuses on the application of PoA to wind generators in ANM schemes, network access is relevant to all generation at both distribution and transmission level and to different energy technologies spanning generation, demand and storage technologies. This area of research will become more important as network owners and operators develop ANM schemes further across the UK network. In particular, the impact of ANM and distributed generation on wider transmission balancing, and the PoA which will apply at grid supply points. (Chapter Two)

Provide a qualitative assessment of PoA based on PoA models in the literature

An extensive review of possible PoA is provided. Selection criteria are developed and used to compare different PoA and the advantages and disadvantages of each are discussed. These criteria have been used in previous reviews of existing regulation and network codes and it is therefore appropriate to apply this to the assessment of PoA. The application to PoA is novel and valuable. This qualitative discussion will identify several PoA for further quantitative analysis in this thesis. (Chapter Three)

Provide a quantitative analysis of PoA based on wind power capacity factors under curtailment action

An OPF method is used to compare the impact of different PoA on the capacity factor[1] of non-firm wind generators connected to a distribution network. OPF has been used in the planning and analysis of both transmission and distribution networks for some time and the method has been adapted in this thesis to curtail generation in the desired order. The impact is demonstrated firstly on a simple four bus example to highlight the basic principles. A real network case study, based on the Orkney distribution network, is then carried out in order to demonstrate the impact of different principles on generators connected to an ANM schemes. This model differs from previous OPF modelling work by incorporating both non-market and market PoA into the model through the use of logic commands that execute in the OPF iterations. This allows all PoA discussed in this work to be compared using the same numerical analysis tool. (Chapter Four and 5)

Assessment of the potential for a curtailment market at distribution level

Currently in the UK, non-market principles of access have been adopted. This thesis presents a discussion on the move of distribution networks towards market-based curtailment approaches in the future. Market based curtailment has yet to be quantitatively analysed at

[1] The capacity factor can be defined as the ratio of actual output over a period of time, to its potential output if it were able to operate at full nameplate capacity continuously over the same period of time.

distribution level and this thesis provides a significant contribution to knowledge in this area. (Chapters 4 and 5)

Assess ANM Business As Usual implications issues for DNOs

As the number of ANM schemes grows in the UK, some DNOs now offer non-firm connections alongside standard firm connections. This work will suggest ways in which DNOs may recover the cost of ANM and curtailment market operation when such a time arises that these schemes are no longer funded through regulator incentives. The method used to demonstrate this cost recovered is a visual demonstration of the flows of goods and services between actors in an ANM scheme, based on a method developed by the Environmental Change Institute at University of Oxford [12]. This is a novel application of this method to ANM schemes and provides insights into how ANM might work in a commercial sense. (Chapter Six)

1.6 Associated Published Work

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

1.6.1 Journal Publications

Kane, L., Ault, G., "A review and analysis of renewable energy curtailment schemes and Principles of Access: Transitioning towards business as usual". Energy Policy, Volume 72, September 2014, Pages 67–77.

Kane, L., Ault, G., "Evaluation of Wind Power Curtailment in Active Network Management Schemes". IEEE Transactions on Power Systems, vol. 30, No. 2, pp. 672-679. 2015

1.6.2 Conference Papers

Kane, L., Ault, G., Gill, S., "New Principles of Access for Wind Generation Curtailment Schemes in Active Network Management". 7th PhD Seminar in Wind Energy, TU Delft (2011).

Kane, L., Ault, G., "The cost of Active Network Management schemes at Distribution Level". European Wind Energy Association Annual Conference, Vienna (2013).

Kane, L., Ault, G., Gill, S. "An assessment of principles of access for wind generation curtailment in active network management schemes." 22nd International Conference and Exhibition on Electricity Distribution (CIRED 2013), Stockholm pp. 1–4, (2013).

Kane, L., Ault, G., Hannant, L., Georgiopoulos, S., "Analysis of Market and Non-Market Principles of Access for Wind Generation connection to Active network Management schemes". CIRED Workshop – Rome, 11-12 June 2014, pp. 1-4, (2014).

Pena-Martinez, J., Williams, C., Kane, L., Ault, G., Norris, E., Moffat, J., Anderson, R., "Curtailment Assessment Methods Characterisation and Definition". 23rd International Conference and Exhibition on Electricity Distribution (CIRED 2015) – Lyon, 15-18 June 2015, pp1-4, (2015).

1.6.3 Reports

The author has been a contributing author on the following publications:

Sinclair, D., Hills, Y., Eyre, E C., Ault, G., Foote, C., Kane, L., Allen, C., Kearney, E., "Actively Managed Distribution and the BSC – Final Report". (2014).

1.7 Summary of Thesis

The structure of this thesis is of similar order to the objectives and principles contributions outlined previously.

Chapter Two provides a background to the research area, including the GB electricity system structure and market operation. Examples of constraint management at transmission level are discussed and a number of ANM case studies are presented with a focus on schemes which apply methods for managing curtailment on the network.

Chapter Three presents a literature review of PoA from previous work by other authors and a qualitative analysis of PoA is carried out. A number of assessment criteria are developed and used to compare the list of PoA identified through the literature review. A number of PoA are selected for further discussion and analysis in Chapters 4 and 5. The best market design is discussed, and a short list for potential market PoA presented. Following this assessment of PoA, a review of modelling techniques is provided and a conclusion is reached regarding the most appropriate method for analysing PoA.

Chapter Four introduces the main modelling methodology used to compare PoA. Both methodologies for modelling market and non-market methods is presented and a simple network example is given. This example will enable the reader to better understand key properties of different PoA before a more complex, real life network case study is presented in Chapter Five. A number of scenarios are presented and the key findings discussed.

Chapter Five contains the main case study for this thesis. A real network case study is used to demonstrate the impact that different PoA will have on the capacity factor of wind generation connected to an ANM scheme. The 33kV network model is based on the Orkney distribution network. Analysis for one year worth of demand and generation data is carried out for each of the PoA, and the results discussed. Further sensitivity analysis is presented to demonstrate the impact that alternative network topology, generation mix and capacity can have on the capacity factor of non-firm wind generation under different PoA.

Chapter Six presents a discussion regarding the cost of ANM schemes and a Business as Usual model is proposed for both market and non-market PoA. The costs of both ANM and traditional reinforcements are presented and the wider impact of ANM on the transmission system is discussed.

Chapter Seven concludes the thesis and brings together the main points from each chapter. The contributions to knowledge are justified and the key thesis question is answered. The chapter concludes with future work.

2 Background

2.1 Chapter Summary

In the last two decades, the UK Government has been making changes to energy policy in order to reduce CO_2 emissions. Carbon reduction targets imposed on the UK by Kyoto protocols [13] in 2005 have led to a growth in the development of renewable generators applying for connection to the GB electricity network. The energy regulator, Ofgem, has provided incentives as part of a wider change to transmission and distribution operation [14]. These changes allow transmission network owners to fast track connection applications which will help to decarbonise the GB energy system by reducing reliance on conventional generation with high carbon emissions such as coal and gas.

The chapter starts by providing background information on the current UK and EU policy on carbon emissions and a summary of the renewables industry. The chapter goes on to provide background on the operation of the current UK electricity market, and the changes that it is undergoing as part of a wider European market reform.

This chapter will discuss examples of constraint management at transmission level which has been increased due to fast tracking of renewable generation connections prior to essential network infrastructure upgrades. In addition to this, the arrangements used to manage electrical interconnectors between the UK and neighbouring electricity systems are outlined along with a brief discussion of how access rights are managed in other industries. This chapter will conclude with a review of Active Network Management (ANM) schemes which are applying constraint management techniques.

The focus of this discussion will be based on wind generators due to the volume of wind generation which has connected to the GB system in recent years. While other renewable systems have connected, wind energy has thus far had the largest impact on the way in which the system operates and in many ways has also led to the changes in operation at distribution level.

In all of the issues discussed in the chapter, the main focus is on the Principles of Access (PoA) granted to the user of the system. While the system conditions vary between distribution, transmission and other types of commodity systems such as gas, telecoms and rail networks, the allocation of network access is of key concern to all users.

2.2 Climate Change and the Renewable Industry

The European Union (EU) is currently in the process of moving towards 'greener' technologies with a drive to encourage the adoption of renewable energy technologies. The threat of climate change is a global concern and the EU governs a significant degree of energy policy in the United Kingdom (UK) through directives which are applicable to all EU member states.

EU Directive 2009/28/EC [15] sets renewable energy targets for all member states to achieve by 2020 in overall energy production and transport. The targets state that 20% of energy generated in the EU and 10% of energy used in transport should be from renewable means. The directive requires member states to set their own personal targets; however these must be consistent with 2009/28/EC.

UK Government targets outlined in the UK Government Low Carbon Transition Plan [16] state that around 30% of electricity will be generated from renewable energy sources by 2020. The Scottish Government has also set its own ambitious targets, aiming for 100% of electrical demand to be met from renewable energy by 2020 [17].

In the UK, as of June 2014, there is a total of 7.26 GW of wind power connected onshore, and a further 3.65 GW installed offshore [18]. The renewables industry has continued to grow in recent years and significant progress toward carbon reduction targets have been made. According to the UK Renewable Energy Roadmap Update [19], 15% of energy demand has been met by renewable sources and in 2013, 15.5% of electricity generated came from renewables. The renewables sector has seen £31 billion of private sector investment with 35,000 jobs created.

According to National Grid's Ten Year Statement [20], the level of Distributed Generation (DG) connected in the period 2013/2014 is 9.8 GW [21] and is forecasted to increase to 21.8 GW by 2020 under the 'Gone Green' scenario. If the capacity of DG continues to increase as forecasted, this will lead to the requirement for new operational and management techniques not just at distribution level, but also at transmission level to deal with a new set of network and system issues created by the growth of distributed connections.

2.3 GB electricity market and regulation

This section gives an overview of the current electricity network operation in the UK. This is the background information for the existing network state, mode of system operation and the market within which it operates. As the number of renewable connections grow, new approaches and techniques may be developed but they must build upon the existing framework. The section then goes on to discuss the regulatory framework, funding initiatives and finally the GB electricity market reform.

2.3.1 Current Electricity Market Operation in the UK

In 2001 the UK established the New Electricity Trading Arrangements (NETA) in a move from a pool to a bilateral market for England and Wales. In 2005, NETA changed to become the British Electricity Trading Transmission Arrangements (BETTA). BETTA includes Scotland, England and Wales.

Figure 2-1 gives an overview of transmission and distribution system interactions. There are three transmission system operators who are responsible for the physical GB National Grid: Scottish Hydro Electrics Transmission Ltd (SHETL) and Scottish Power Transmission (SPT) in Scotland, and National Grid Transmission Operator in England and Wales. These bodies are responsible for maintaining the transmission assets in each of their own regions. In addition to maintaining the English and Welsh transmission system, National Grid is responsible for managing the balance of supply and demand for the whole of the Main Interconnected Transmission System (MITS) i.e. for the whole of GB.

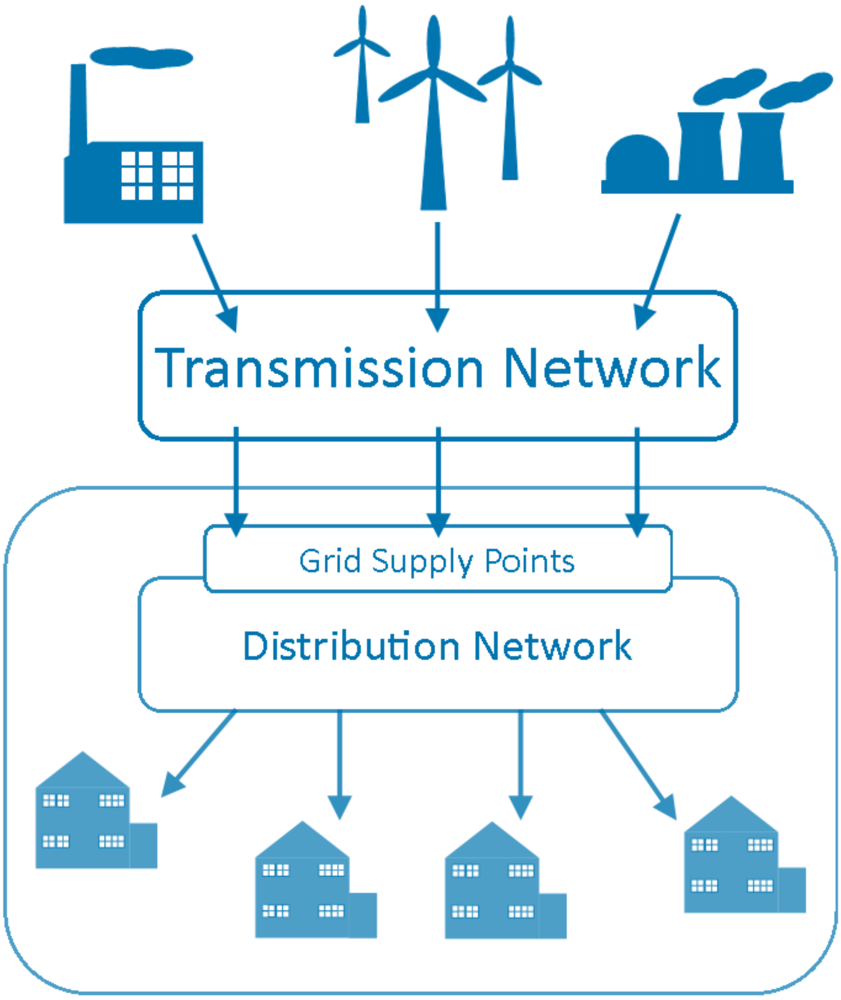

Figure 2-1 Overview of transmission and distribution system [16]

Ofgem [22] is the industry regulator, and is responsible for ensuring that the gas and electricity markets continue to offer value for money to energy customers. They are also responsible for monitoring the investments of gas and electricity network owners in order to ensure security of supply for current and future users of the system. Ofgem regulates transmission and distribution Network owners and operators, as well as energy suppliers.

There are 14 licensed distribution network areas, as indicated in Figure 2-2. Each distribution network has its own network owner and operator, commonly referred to as the DNO. They are in charge of maintaining the network assets as well as managing the network and ensuring the system stays within limits and continues to provide electricity to customers.

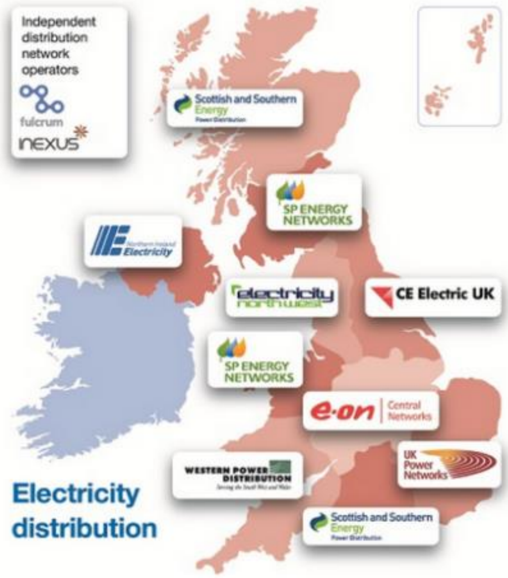

Figure 2-2 UK Distribution Network Operators [17]

The electricity market in Great Britain allows customers to choose the supplier of their choice, and for suppliers to buy electricity to meet customer demands from generators of their choice. This market is dominated by the Big Six – Npower, British Gas, EDF Energy, E. ON UK, Scottish Power and SSE. There are many smaller energy suppliers on the UK market and customers are free to change suppliers as and when they please.

Organisations without a physical demand for electricity or any means of generating electricity (Non Physical Traders) such as banks are also entitled to trade electricity on the GB electricity market.

Elexon is the Balancing and Settlement Code Company (BSCCo) [23] established under the provisions of the Balancing and Settlement Code (BSC). Elexon is in charge of calculating how much each generator and supplier owes the system after gate closure. The BSC contains the rules and governance arrangements for electricity balancing and settlement in GB, and Elexon is responsible for ensuring its proper implementation.

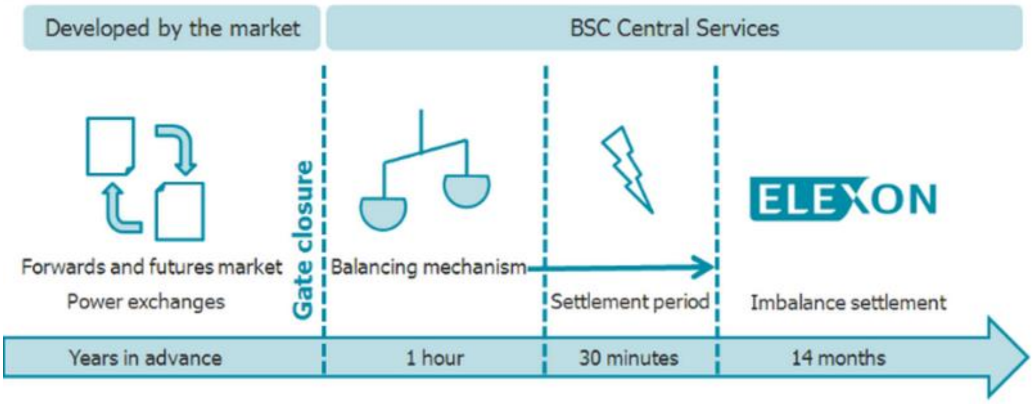

Figure 2-3 Overview of the settlement and balancing process [18]

Figure 2-3 provides an overview of the market operation within the GB electricity market. Each of the stages are explained in more detail below.

The grid is a dynamic system, and therefore it is difficult to calculate the exact level of generation and demand acting during any half hour period. The Balancing Mechanism (BM) allows the system operator to increase and reduce generation as required.

Years in advance of the gate closure (i.e. the spot time one hour before the spot time at the start of that settlement period), long term contracts are struck between energy suppliers and generators. These contracts guarantee levels of generation at a fixed price and are typically used for generators who provide the base load. Power exchanges are used to 'add shape' to the supply profile and more closely match the demand profile. These are carried out closer to gate closure. As the gate closure approaches, finer system balancing takes place.

In the hour following gate closure, bids and offers from generators participating in the BM (BM units) are accepted. BM units must submit an expected level of generation/demand during the settlement period which is known as a Physical Notification. After gate closure this becomes Final Physical Notification (FPN). BM Units also submit bid-offer data which indicates the ability of the unit to move away from FPN after gate closure in return for payment.

In the minutes and seconds before the operating point, the system operator can call on additional balancing services known as ancillary services [24]. This includes support for reactive power, frequency response, back start capability and reserve. These services are contracted in advance. Some ancillary services, such as frequency response, must be provided as part of a participant's grid connection agreements. For many of these services, generators receive an availability payment in addition to a utilisation payment. Due to the short response time required for services such as frequency response, generators must be available to increase or decrease output at short notice.

Following the end of the settlement period, metered volumes are collected from generators and suppliers and compared to contracted volumes. Imbalances must be paid for by all parties. If units generate more than contracted for, they must sell additional electricity to the system. This is known as the 'System Sell Price'. If the unit uses more electricity than contracted for then they must buy from the system at the 'System Buy Price'. These prices are calculated by summing up daily charges and adding VAT. Other charges and payments, such as constraint payments are also calculated during settlement.

All units connected to the transmission system must be fitted with 'Half Hourly' (HH) metering system which feed directly into settlement calculations. However, units connected to the distribution system such as houses are not fitted with HH meters as standard. Using profiling, an annualised value of demand is calculated and used in settlement calculations. As more accurate data is gathered, the calculations are repeated on four occasions spaced across fourteen months, providing a more accurate picture of settlement each time. All imbalances are settled centrally and managed by Elexon.

2.3.2 Regulation of Transmission and Distribution Operators

The RIIO (Revenue = Incentives + Innovation + Outputs) framework was developed by Ofgem following a review of the previous energy network regulation model, RPI-X. The results of the review, referred to as RPI-X@20 [14], recommended that RIIO be created to help network companies plan for secure and reliable future networks whilst dealing with issues caused by the move towards low carbon technologies i.e. changes in demand and generation behaviours.

The key objectives of RIIO are to encourage network companies to:

- Include stakeholders in the decision making process
- Invest to ensure safe, secure and reliable future networks
- Provide innovative solutions to reduce network costs for consumers
- Strive towards a low carbon future

RIIO-T1 is the transmission price control review for the period 2012-2022. National Grid, SP Transmission and Scottish Hydro Electric Transmission Ltd have published their proposed spending [25], [26]. Both proposals included extensive stakeholder engagement, as encouraged by the RIIO framework. These documents set out information regarding what the network company will deliver during the control period, the incentives that are placed upon this delivery, the costs network companies are allowed to recover and the method for calculating this cost and arrangements for addressing any risk and uncertainty that might arise during the review period.

Similarly to RIIO-T1, each DNO has published business plans as part of the RIIO-ED1 price control review. These business plans outline how each of the 14 distribution network areas will meet the obligations set out by Ofgem under the RIIO framework. UK Power Networks [27], Northern Power Grid [28], Electricity North West [29], Scottish and Southern Energy Power Distribution (SSEPD) [30] and Scottish Power Energy Networks (SPEN) [31] have published highlights and full electronic copies of business plans online. Each business plan addresses similar issues to those discussed at transmission level i.e. ensuring safe and secure access to future networks whilst innovating and improving on existing techniques to allow increased distributed generation connections. All DNOs have worked closely with stakeholders to develop plans and have made changes based on discussions. For example, SP Energy Networks increased spending by £20 million as a result of stakeholder priorities and the stakeholders willingness to pay towards these projects [31].

2.3.3 Renewable Generator Subsidy Payments

Renewable technologies are still developing; therefore to encourage the connection of renewable generators, a number of incentives were introduced by the UK Government, including the Feed-in Tariffs (FITs) [32] and the Renewable Obligation (RO) [33]. These are provided to help developers ensure that a minimum price per unit of electricity can be recovered.

The RO is the most significant incentive for renewable generation development in the GB energy market. Generators are rewarded Renewable Obligation Certificates (ROCs) for each MWh of energy produced by renewable energy sources. The value of ROCs has an important impact on the price paid to the renewable generator for electricity produced. The ROC price is set at a fixed rate for each year, while the market price of electricity fluctuates, and the long term value of the Power Purchase Agreement [2](PPA) is typically lower than the average market rate [34].

The number of ROCs awarded varies depending on the technology; this encourages more investment in less developed technologies [35]. The value of ROCs is set by Ofgem each year and will change over the years in line with the Retail Price Index (RPI). An example of ROC prices can be found online at the e-ROC website [36]. The average ROC price in 2014 was £41.82. ROCs will be available to generators until 2017 when they will be replaced by Contracts for Difference (CfD). This topic is covered in more detail in Section 2.3.5. ROC banding for a selection of different generation types are shown in Table 2-1 below.

Table 2-1 Annual ROC banding levels for different renewable technologies (2013 – 2017) [37]

Year	13/14	14/15	15/16	16/17
Onshore wind	0.9	0.9	0.9	0.9
Offshore wind	2	2	1.9	1.8
Tidal	2	2	1.9	1.8
Wave	2	2	2	2
Hydro	0.7	0.7	0.7	0.7

Feed in Tariffs (FITs) are awarded to generators smaller than 5 MW and the rates vary depending on the size of installation and the technology used. FIT prices are set by Ofgem each year. Prices for wind generation are shown in Table 2-2 below, details of tariffs paid to other generation are given in [38]–[40]. This subsidy is aimed at smaller generators, and to encourage the use of micro generation at a domestic level.

[2] A Power Purchase Agreement is a long term contractual arrangement between a generator and an energy supplier where a fixed price is agreed for a fixed volume of energy.

Table 2-2 Feed-in Tariff payments (p/kWh) for wind (2010-2014) [38]

	April 2010 – March 2012	April 2012 – November 2012	December 2012- March 2014	April 2014 – March 2015
Less than 1.5kW	40.12	37.91	22.23	17.78
1.5kW – 15kW	31.03	29.65	22.23	17.78
15kW – 100kW	28.06	26.90	22.23	17.78
100kW – 500kW	21.81	18.53	18.53	14.82
500kW – 1500kW	11.01	10.05	10.05	8.04
Greater than 1500kW	5.19	4.74	4.26	3.41

2.3.4 Innovation Funding for Network Operators in GB

In the last decade or so, Ofgem has produced a number of different funding initiatives that run alongside price control reviews. These funds help network owners to develop new methods of operating and managing the system in order to facilitate changes in typical behaviour. Innovation funding allows networks to trial solutions to complex network problems without the need to impose massive costs to the business and in turn, reduce the costs passed on to electricity customers.

2.3.4.1 Innovation Funding Incentive (IFI) and Registered Power Zones

In 2004, Ofgem introduced the Innovation Funding Incentive (IFI) and Registered Power Zones (RPZ). These schemes were created to deal with the growing number of connection applications from small generators, in particular renewable generation, who were wishing to connect at distribution level. Due to lack of available network capacity, connection offers were high which was discouraging to smaller generators. There is a high cost and long time frame associated with traditional network upgrades i.e. building more transmission lines, or increasing the capacity of existing equipment.

RPZs focused on the development of new and more cost effective connection and operating techniques at distribution level. Three sites were awarded RPZ status: Orkney, Skegness and Marsham Primary. Orkney is now a fully operational ANM scheme and is currently receiving a second round of funding for the development of a storage park [41]. Skegness Dynamic

Line Rating (DLR) project is now being further developed by Western Power Distribution as part of the Lincolnshire Low Carbon Hub [42].

2.3.4.2 Low Carbon Network Fund

The Low Carbon Network Fund (LCNF) [4] was set up in 2009 Under the RPI-X framework to encourage distribution network owners to develop innovative solutions to ensure safe and secure network operation while the industry moves towards a low carbon generation mix. The LCNF was designed to follow on from RPZ funding.

There are two tiers to LCNF: the First Tier of funding allows DNOs to recover a proportion of the expenditure of small scale projects. In order to gain funding under the First Tier, projects were asked to trial new or unproven equipment, novel arrangements of applications of existing distribution system equipment, novel operational practices or commercial arrangements. Under the First Tier, 11 projects were awarded funding.

The Second Tier of funding ran as an annual competition between 2010 and 2015 to run alongside the distribution price control review. Up to £64 million of funding was available each year to help fund a small number of 'flagship' projects. A key part of the LCNF project conditions is knowledge sharing and it is expected that each project should provide some valuable learning experience that all DNOs can use for future network developments. Projects were asked to demonstrate that they could enable the development of a low carbon energy sector and provide financial benefit to future or existing customers. This is in line with the objectives of the new RIIO regulatory framework.

The Second Tier of funding has been granted to 20 projects to date, with a further four projects receiving funding under the 2014 competition. Details of all Ofgem's innovation funding projects can be found on Energy Network's Association (ENA) Smarter Networks portal [43] .

2.3.4.3 Network Innovation Competition

More recently, to encourage network innovation, 'Network Innovation Competitions' (NICs) have been introduced [44] as part of RIIO T1 review . Transmission network operators can compete for funding for innovation projects which meet the relevant evaluation criteria. There is £27 million of funding available each year to support innovation projects and this will be awarded to the projects which can demonstrate methods to provide environmental benefits, cost reductions and security of supply in GB during the move towards a low carbon economy.

2.3.5 GB Electricity Market Reform

The GB electricity market is currently undergoing a number of changes, as part of the Electricity Market Reform (EMR) [45]. The EMR was proposed by DECC in 2012 under the proposed Energy Bill [46]. The aim of EMR is to ensure that the correct investment is secured in order to provide a reliable and diverse low carbon energy mix for the future. The EMR will provide the processes and mechanisms that will allow low carbon technologies to compete with more established gas and coal technologies.

The UK Government will set all the policy required under the EMR which will include establishing key parameters for capacity auctions and setting prices for low carbon technologies. They will look to National Grid as the system operator to provide them with evidence and analysis to aid in setting these parameters.

The two new market mechanisms created under EMR are Feed-in-Tariffs with Contracts for Difference (CfDs) and Capacity agreements within a capacity market. These mechanisms are supported by a Carbon Floor Price and an Emissions Performance Standard.

The four stage plans proposed under the EMR are outlined in Table 2-3.

Table 2-3 Timescale of EMR Stages (Present – 2020 and beyond) [47]

Present – 2017	2017-2020	2020s	2020s and beyond
Capacity Auctions run as needed			
RO will run alongside proposed Contracts for Difference (CfDs) with prices set administratively. Capacity auctions could be utilised depending on the security of supply.	As technologies mature, some may be able to enter into competitive technology specific auctions. Capacity market could be fully operational.	All technologies have fully matured and there will be a move towards technology neutral auctions. Demand Side Response, additional storage and interconnection will contribute to managing the system.	Carbon price is set high and at a sustainable level to allow all generators to compete without intervention.

2.3.5.1 Contracts for Difference

The aim of CfDs is to remove the long term exposure for low carbon technologies to volatile electricity prices and will replace the current ROCs. CfDs ensure that generators receive payments for energy produced at a fixed price, known as the 'strike price'. Examples of strike prices for different renewable technologies are provided in Table 2-4. If the electricity price is lower than the strike price, low carbon generators will receive a top-up payment to make up the difference from suppliers. However, if the electricity price is higher than the strike price, then low carbon generators must pay back the difference. They will remain participants in the wholesale energy market. The diagram in Figure 2-4 helps to demonstrate this process.

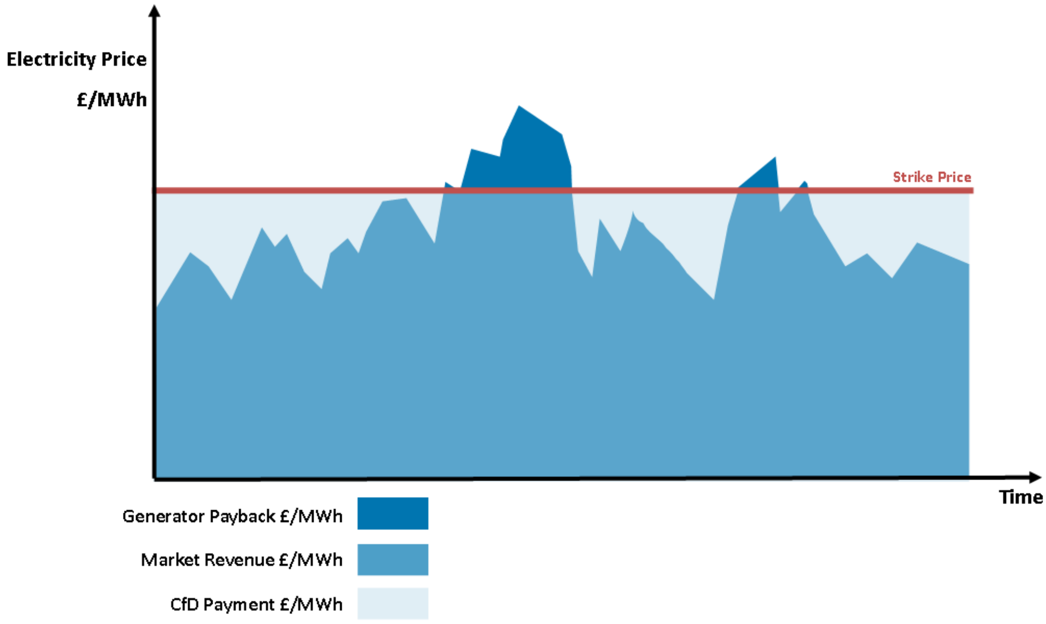

Figure 2-4 Diagram of how contracts for difference will operate

The aim is to standardise CfDs across technologies with a distinction made between base load and intermittent generation. The government will also 'grandfather' CfDs i.e. a CfD cannot be changed once issued other than according to pre-agreed circumstances. The start date for claiming CfD payments is April 2015, and generators can choose to claim either CfD or ROC payments until 2017.

The EMR White Paper [48] justifies CfDs by saying that, they improve long-term revenue certainty, they lower the cost of capital for low carbon generators, they retain short-term market signals for efficient operation, and they are a more cost effective and will therefore reduce costs to consumers.

Initial strike prices have been set and a consultation on these prices is ongoing. Table 2-4 shows the proposed strike prices. Onshore wind is considered to be a mature technology and therefore receives a lower strike price when compared with other technologies. A Nuclear strike price of £92.50/MWh has been agreed between the UK Government and EDF who have plans to construct at least one new nuclear plant by 2023. If they continue with plans to construct a second nuclear plant, the strike price will decrease to £89.50/MWh as it is assumed some of the construction costs could be split between both projects.

Table 2-4 CfD strike prices (£/MWh, based on 2012 prices) [49]

Technology	2014/15	2015/16	2016/17	2017/18	2018/19
Offshore Wind	155	155	150	140	140
Onshore Wind (>5 MW)	95	95	95	90	90
Wave and Tidal	305	305	305	305	305
Solar PV	120	120	115	110	100
Hydro (>5 MW and <50 MW)	100	100	100	100	100

2.3.5.2 Capacity Market

The aim of the proposed capacity market is to ensure there is enough capacity available on the GB system to meet demand. The total amount of capacity required for the future peak demand will be contracted through a competitive central auction a number of years in advance. The auctions are open to new and existing generators and will only be run as needed. Those who are awarded contracts, agree to provide electricity when required in the delivery year in return for a steady capacity payment – similar to the Power Purchase Agreements (PPAs) already taking place. Inability to provide capacity when required will result in penalties. The cost of payments are socialised between electricity suppliers.

One of the important factors in the EMR is the inclusion of significant Demand Side Response (DSR). DSR has the opportunity to participate in the capacity market one year ahead of required response, which allows the system operator to carry out a certain level of fine tuning on accepted bids.

2.3.5.3 Additional EMR Support Mechanisms

In order to continue investment into low carbon technologies, the EMR has proposed a number of support mechanisms.

The Carbon Floor Price will provide an incentive to move away from high carbon technologies. This price is applied to technologies which emit carbon while generating electricity and currently exists in the GB electricity market as a Carbon Tax, or Climate Change Levy.

The Emissions Performance Standard (EPS) will provide a limit on the amount of emissions a fossil plant can emit. The level is set at 450g/kWh equivalent for all new fossil fuel plants and power stations will be subject to this constraint until 2045.

2.3.5.4 Industry views on the EMR

The market reform has created some uncertainty in the industry, and the majority of users of the system have approached the reform with caution. A report from the Committee on Climate Change [50] states that the uncertainty of the electricity market beyond 2020 could render the policies put in place by the EMR useless. A number of strategies are proposed in order to help boost confidence in the system, including:

- Further carbon reduction targets up to 2030
- Extending support of low carbon technologies to 2030
- Setting out options for financial support for new developments including roles for Green Investment Bank and Infrastructure UK

Visibility of the system beyond 2030 would allow developers to better gauge an appreciation of return on investment, provide confidence that the UK is committed to a low carbon energy future and allow the UK to meet ambitious renewable energy targets.

With regards to ANM schemes and distribution connections the EMR will continue to promote the connection of renewable generators. The strike price for less developed technologies such as wave and tidal is high in comparison to more developed technologies such as wind generation.

2.4 Congestion Management of Wind Generators Connected at Transmission level.

In recent years, congestion management has become an increasing concern to network owners and operators due to the drive to connect renewable generation such as wind generators to the network in GB. Connect and Manage [5], introduced by National Grid in 2001, has resulted in a large volume of renewable generators being granted firm access to the transmission system without the need to wait until network upgrades had been carried out. These values are shown in Figure 2-5 below. On the same graph, the costs of constraints are also shown – there has been a significant increase in constraint costs in line with increased renewable generation. This section will discuss the network and system issues created by transmission constraints and the problems encountered by both generators and network operators.

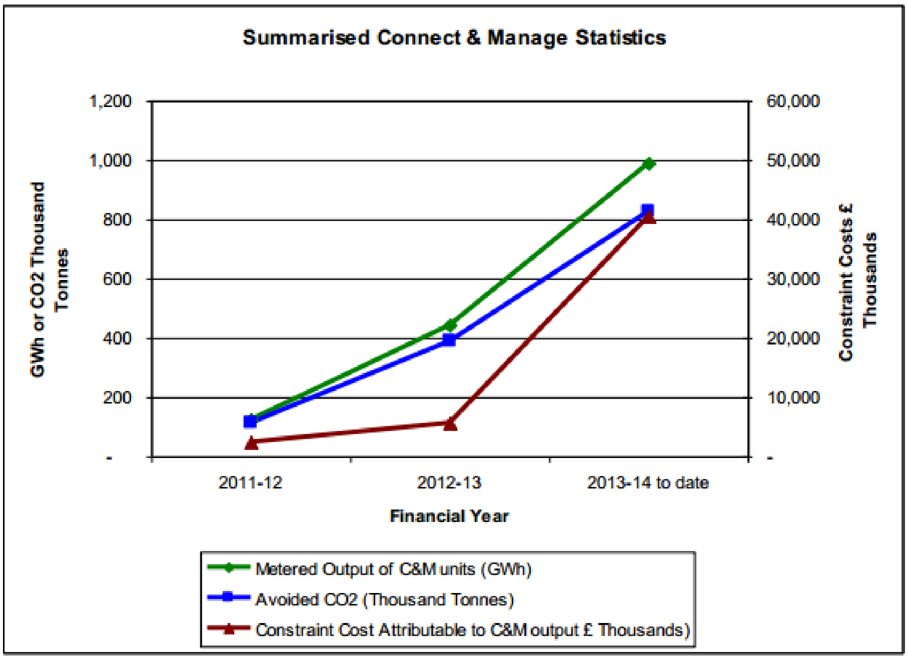

Figure 2-5 Summarised Connect and Manage statistics demonstrating the increase in connected generation since 2011 in GB [51]

2.4.1 Transmission Constraints

There are a number of methods which can be used to resolve grid congestion. A technical report from CIGRE [46] covers a number of these methods in Section 5 of the report.

For intra-zonal congestion management i.e. for a constraint within a single area of the transmission network, the method very much depends on the market structure adopted e.g. bilateral, pool or Locational Marginal Price (LMP). In the GB market, constraints are solved in the bilateral market by accepting generator bids to be curtailed. These can be positive or negative bids. For example, a coal plant may choose to pay the system to reduce its output because it will save money on the fuel that has not been used. In contrast, a wind generator may choose to submit a negative bid as they do not wish to be curtailed while there are wind resources available to generate electricity.

For cross-border congestion management, it is suggested that allocation of capacity will be through the use of auctions. Types of auction listed are Explicit, Implicit and a Hybrid of Explicit and Implicit [52].

An implicit auction is an auction which allocates transfer of capacity as a function of energy prices. In an explicit auction, transfer capacity and energy are two separate markets.

Other options for cross border congestion management include 'pro-rata rationing' and 'priority-based rules' which can be directly compared with Pro Rata and LIFO techniques for curtailment at the distribution level (See Chapter Three).

In order to guarantee prices for market participants, financial products can be used to hedge against unstable prices which are made worse by congestion. Examples of financial products include Financial Transmission Rights (FTR) and Contracts for Differences (CfD), similar to those proposed under the GB EMR.

An FTR gives the holder the right to a share of congestion rents received by a system operator during congestion. FTRs are typically allocated at an auction designed by the System Operator. In the UK, FTRs are also granted to customers who pay embedded costs of the transmission system.

2.4.2 Integration of Wind Power to the Transmission System.

Due to the variability of the wind resource and the issues surrounding forecasting and system balancing [53], wind generators cannot provide output forecasts with the same level of accuracy as conventional generation. The system operator must turn to other generation such as gas and hydro to compensate for this intermittency via the reserve ancillary service and balancing mechanism.

The following papers are examples of how large scale wind can be integrated into transmission networks with constraints and the issues which may arise from variable wind generation.

Ummels et al [47] discuss the technical capabilities of thermal generation plants to meet the gap in supply left by variations in wind generation output. The Dutch transmission system, unlike the GB system, does not have large hydro schemes which are ideally suited to meeting the shortfall left by wind. The Dutch TSO relies on gas plants to provide reserve, however some of these plants provide both heat and power (CHP Units) and are therefore restricted in the level of reserve which can be provided. A simulation using a unit commitment model was used to determine the technical limits to system balancing with large-scale wind power – transmission constraints and market design were neglected. The results of the simulation highlight a number of issues; mainly the increased penetration of wind power will lead to an increase in curtailed wind during low demand periods. To resolve these, the number of additional heat boilers in the CHP units could be increased to cover heat demand on the system. The level of wind curtailment would then be reduced. The simulation also found that variations in wind power prediction only has a minor impact on the balancing in the Dutch power system.

Siemes et al [48] present five methods which may improve integration of wind power into the German interconnected system:

- generation management of wind turbines
- intraday markets
- demand-side management
- improved load forecasts
- modern storage technologies

The generation management method asks wind generators to reduce their output when the wind forecast error exceeds a trigger point. The forecast error of wind has an impact on the level of reserve required on the interconnected system.

Intraday markets use short-term forecasts of wind power. This reduces the uncertainty which is experienced in the current day-ahead markets, and intraday markets would be used to supplement the day-ahead market. Through the use of intraday markets, the amount of reserve which must be purchased to balance the system would be reduced.

Demand-side management already exists to some extent with larger industrial customers on the transmission system. The author suggests demand side management of private customers is an option for controlling imbalance on the system and reducing the level of reserve required. However, the paper presents no quantitative figures or graphs to support this discussion.

Germany is split into four control areas, and this can increase the impact of forecasting errors on reserve levels. There is a possibility of pooling load forecast errors and dividing them according to the share in annual electricity sales in each area. This would reduce the total demand of control reserve in Germany by approximately 20%. However, this method would increase operating costs and possibly increase power flows in particular areas of the network, leading to overloading of lines.

The author suggests aggregating wind power with a storage technology and controlling using a Virtual Power Plant (VPP). The storage method proposed is Compressed Air Energy Storage (CAES) which has similar operation to that of pumped storage plants. Another option is to use CAES as a reserve power plant which the author deems to be more economically feasible than using CAES in a VPP configuration.

Short term access trading [54] is one method identified as a possible short-term solution to the problem of transmission access rights to integrate renewable generation. The principle works by trading generation capacity between renewable generation and conventional generation in particular transmission network zones to make efficient use of renewable generation whenever possible. For example, when wind conditions are good, access rights can be traded from the conventional generator who has firm access rights to the wind generator with non-firm rights. Trading could also take place during planned outages of the conventional generator or during periods when wind conditions are poor. DC power flow analysis is used to determine which generators can trade access rights between each other. Difficulties in trading agreements may arise because of generator size. Wind farms may need to buy more access rights than they require because it may not be possible for the generator which the wind farm is trading with to reduce output by the required fraction. The scale of this issue depends on trading partner size and technical specifications.

These examples demonstrate a number of solutions to the issues cause by to high wind penetration, in particular reinforcement of the system and demand side/storage solutions.

The next sub section provides an example of ways in which wind curtailment has been managed on transmission systems outside of the UK.

2.4.3 International Examples of Wind Curtailment

A document published by National Renewable Energy Laboratory (NREL) [54] in the United States presents Wind Energy Curtailment Studies on transmission systems in the US and in Europe. The examples below highlight examples that are of particular interest to this research.

2.4.3.1 Electric Reliability Council of Texas (ERCOT)

In 2009, ERCOT moved away from a zonal market to a nodal market structure. The zonal market system operates a real-time market which calculates a market clearing price for energy (MCPE) in 15 minute intervals. The lowest cost generator will be allocated capacity first, which can in some cases lead to congestion on the transmission system. To compensate for this, ERCOT procures 'Out-of-Merit Energy' (OOME), used to relieve congestion. Generators which offer OOME services are compensated with MCPE for lost energy.

By switching to a nodal market, there will be an improvement to the way in which energy is dispatched and curtailed across the system. Generation will be settled based on locational marginal pricing (LMP) of the node where the generator is located. Settlement prices for local congestion will also be based on LMP.

In 2011, Sharma et al [55] published a paper on some of the tools ERCOT are using to manage the increase of wind connected to their transmission system. To indicate that curtailment is required, the system operator will send a 'flag' to the generator. This is a set point notification of allowed output. Other tools help with frequency response, and to assess the reliability of forecasted wind output on a day-ahead and hour-ahead basis.

2.4.3.2 Midwest ISO

Midwest ISO is the network operator for 15 states in the mid-west area of the United States. The Minimum Generation Task Force (MGTF) was established in 2008 as a stakeholder process to examine minimum generation situations and provide guidance on how best to manage and prevent minimum generation situations occurring. The priority is to achieve efficient price signalling during periods of congestion and then allowing the market to solve the problem.

A short term solution to solve congestion involved curtailing resources with the shortest restart time i.e. variable sources such as wind. This was developed into a more comprehensive approach which considered Reliability Assessment Commitments, day-ahead schedules and markets, LMP and Transmission Loading Relief. Once these have been considered, and the congestion has still not been relieved, wind farms will be curtailed on a pro-rata basis.

2.4.3.3 New York Independent System Operator (NYISO)

NYISO uses the energy market to determine the least-cost means of meeting load requirements while maintaining reliability. Generators indicate their willingness to curtail via economic offers. The market accepts bids 75 minutes prior to the operating hour in question. Zero and negative bids can be accommodated in the market. Financial penalties are incurred for generators who do not respond to curtailment orders. This is a similar method to the one adopted in the GB system.

2.4.3.4 Xcel Energy

Xcel Energy in the United States provides transmission services for eight Western and Midwestern states catered for by a number of regulated subsidiaries.

Xcel Energy has an agreement with the wind generators in south-western Minnesota establishing responsibility for curtailment on a rotational basis between various plants. Plants that have been curtailed are compensated by Xcel Energy for the value of lost energy and federal production tax credit (PTC) which is a similar incentive to ROCs. However this has cost Xcel Energy on average $500,000 a month, with the exception of winter 07-08 which costs peaked at over $3 million as shown in Figure 2-6.

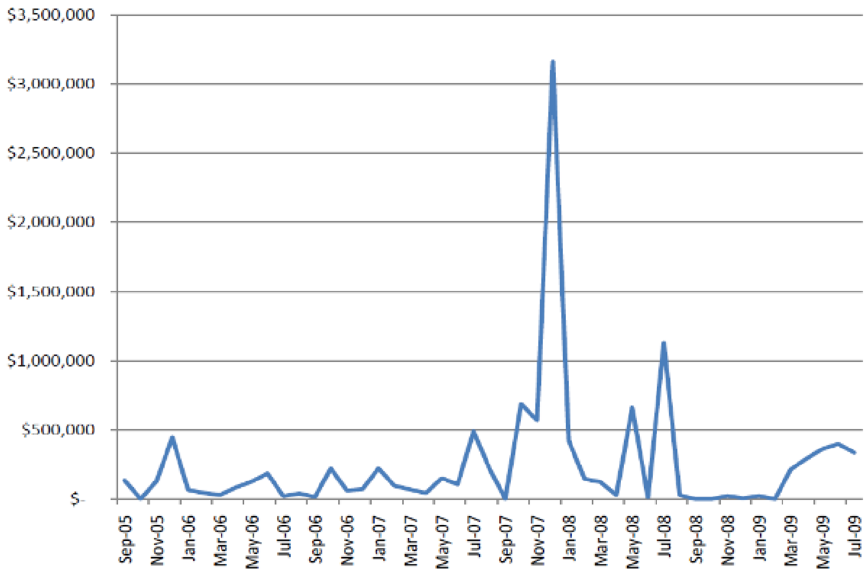

Figure 2-6 Monthly wind curtailment payments in Minnesota by Xcel Energy Sept 2005 - July 2009 [65]

In Colorado, Xcel has a contractual agreement with Logan Wind plant to provide up to 14,000 MWh of annual curtailment at no cost. A number of other plants have similar contracts for lower volumes of curtailment, and are curtailed after Logan wind farm is curtailed. Following these, curtailment of energy purchases takes place. If the network is still congested, generation is curtailed outside of the contractual arrangements, by referring to a schedule based on the day of the month.

2.4.3.5 Alberta, Canada

Wind power is accepted by the TSO – the Alberta Electric System Operator (AESO) when available. As wind is a 'price taker' who does not submit bids on the market, it is only curtailed during system failures, and not during congested periods. Generators who are curtailed are divided into two groups: flexible and inflexible. Flexible generation is curtailed by an amount related to its contribution to the supply (pro-rata) and inflexible generators are reduced to minimum generation levels. A review of market operation was carried out in 2007 in order to better accommodate the integration of wind generation. It was suggested that wind generators should become actors in the current energy market and contribute towards ancillary and balancing services. Wind generators are required to pay the costs of upgrading control systems and the installation of wind forecasting but will not be compensated for lost production due to curtailment. Further studies in 2009 introduced the sharing of curtailment during congested intervals between flexible, inflexible and wind generation. A System Wind Power Limit (SWPL) will be calculated using data obtained during market bids and wind forecasts and the SWPL amount will be allocated to wind generators on a Pro Rata basis. Wind curtailment will be re-assessed and re-allocated every 20 minutes if the limit for any one wind project changes by more than 5 MW.

2.4.3.6 Germany

There are four German TSOs, and each is obligated to take all electricity generated from renewable energy sources within their control area and pay for this energy at an established tariff rate in accordance with German Federal Act on Granting Priority to Renewable Energy Sources. The renewable energy produced is operated under a common electricity market and balanced among the four TSOs. The cost of purchasing renewable energy is shared equally between the four TSOs regardless of location of renewable generators. Balancing is carried out on the day-ahead market by European Energy Exchange and the real-time market exchange is settled accordingly with settlement data.

All generators greater than 100kW are subject to curtailment, which system operators must pay compensation for. The system operator must first demonstrate that all possible measures to optimize, improve and expand network capacity were taken before curtailing generators.

There are a large number of transmission upgrades being carried out by all four TSO in order to provide the capacity for forecasted wind generator connections.

2.4.3.7 Spain

Dedicated control centres (CECRE) for renewable generators greater than 10 MW were established in 2006 by Spanish grid operator, Red Eléctrica de España (REE) and these feed into the Spanish system operator CECOEL. Renewable energy facilities are grouped together by General Coordination Centres (GCC) which co-ordinates, controls and supervises the system using SCADA systems. By using this method of coordinated control, the system operator uses a computer model called GEMAS which determines the maximum admissible wind power generation on the system. Information received every 12 seconds feeds into simulation models that determine the need for curtailment of wind power facilities.

In Spain, there are two methods of curtailment. Firstly there is programmed curtailment where curtailment decisions are made before the day-ahead market is closed. Secondly there is a real time market where instructions are sent out from the system operator to the wind generators via the Control Centre for Renewable Energies (CECRE) via the Generation Control

Centres. All real-time curtailment receives compensation of 15% of the wholesale price for each hour without premium which is multiplied by the theoretical production based on the wind forecasts.

2.4.3.8 Greece

EU Directives have determined that networks must accept all output from wind farms, which has led to the allocation of firm contracts on the Greek transmission system. This is possible for the time being, but there is a limit to the amount of firm generation which can be connected due to the existence of thermal generation which has a minimum technical output. This problem could be solved via the use of Interruptible Contracts, which is the subject of a paper by Kabouris [66]. The paper proposes the use of either Preventative or Corrective control to manage the curtailment of wind generators.

Preventative control allows wind farms to connect up to the security limit of N-1 contingency[3]. If this limit is violated at any time, the controller will curtail wind farms using a pro-rata method. The method of curtailment is not the subject of the paper and therefore is only a suggested method. Using preventative control would allow a further 100 MW of non-firm wind generation to connect, in addition to 40 MW of firm generation. 160 MW of wind generation could be connected if all farms had non-firm contracts.

Corrective control curtails wind generators when the thermal transfer limit of the line is violated. This would require significant changes to the grid codes, however if implemented 200 MW of additional wind generation could connect.

Figure 2-7 shows the result of calculations based on the Preventative Control method. The graph uses the capacity factor of wind generators to determine the maximum level of generation which is economically feasible to connect.

[3] An N-1 Contingency is the loss of a single element of the power system, e.g. the loss of a single line.

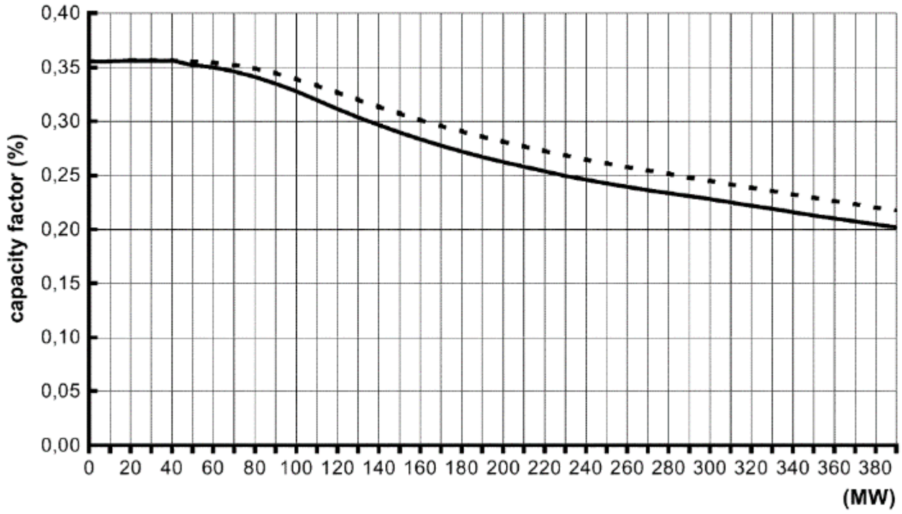

Figure 2-7 Estimated variation of capacity factor versus total wind capacity. The solid line indicates typical operation; the dash line is the result using preventative control [66]

2.4.3.9 Northern Ireland and the Republic of Ireland

Single Electricity Market Operator (SEMO) is the wholesale electricity market for the Republic of Ireland and Northern Ireland. It operates a gross mandatory pool market in two different currencies. The market is a joint venture between EirGrid, the Transmission System Operator (TSO) for the Republic of Ireland, and SONI Ltd, the TSO for Northern Ireland.

EirGrid and SONI have carried out a number of network studies to assess the impact of wind penetration on the grid. The island currently has two interconnectors to the GB system, and the instantaneous wind penetration often accounts for 50% of Irish demand [56]. A study published by members of EirGrid in 2012 [57] discusses some of the online tools being used by the network operator to manage these high volumes of wind. In order to meet renewable targets, operational policy and new techniques must be applied. The Wind Dispatch Tool (WDT) allows EirGrid to issue dispatch commands to groups or individual turbines i.e. curtail all wind on the system, or constrain individual turbines behind local constraints. Wind farms connected to EirGrid will be curtailed on a Pro-Rata approach, while SONI uses a Rota curtailment approach [58].

Wind farms connected to the SONI and EirGrid networks are given non-firm connections and are therefore not granted compensation for curtailment. Wind farms with firm connections are compensated in the same way as conventional generation. A decision paper from SEMO [59] in 2013, states that as of January 2018 there will no longer be compensation for any wind farms. This judgement was based on the assessment that wind was already given priority dispatch over conventional generators, and only curtailed due to system security issues. This decision was viewed as controversial, as it adds an uncertainty for many wind generators. Many investment decisions may have been made assuming long term compensation, which is now to be withdrawn. This decision paper is a bold move for the system operator - and the first of its kind to ignore grandfathering of connection rights.

2.5 GB Interconnector Capacity Allocation

Similar to the management of generators and network congestion, there a rules which dictate the access rights of interconnectors to and from other electricity networks in Europe. There are four interconnectors which connect the GB Grid to neighbouring grid systems: Northern Ireland, Republic of Ireland, France and the Netherlands as shown in Figure 2-8. These interconnectors make up 4GW of capacity, which is around 5% of the total GB capacity. [60]

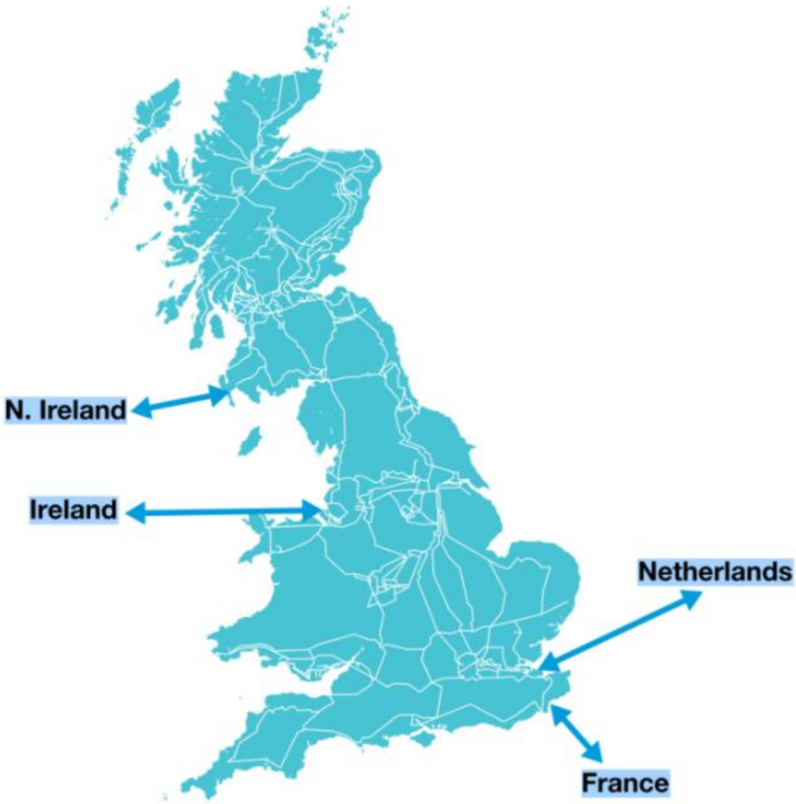

Figure 2-8 Interconnectors connected to the GB transmission system [60]

Each interconnector can import and export electricity depending on price differentials between markets. Interconnectors benefit customers by taking advantage of cheaper electricity by importing power from other markets, and benefits generation by allowing an increase in revenue through export to other markets.

The access rules for some of the interconnectors are detailed below. These rules focus on the capacity auctions that are carried out to determine who has the right to use the interconnector at any time period, similar to the balancing mechanism on the GB systems.

2.5.1.1 Moyles and EWIC Access Arrangements

Under access rules published in September 2012 [61] there will be three types of auction for generator units to participate in:

- Long Term Auction
- Daily Auction (Day-Ahead)
- Intraday Auction

In each auction, the available units of capacity are auctioned in addition with 'resale' units (unused units that have become available) for the secondary market. All unit prices are entered in pounds per MW per hour (£/MW/h). Users can set maximum bid parameters, prices and volumes to prevent bid errors being accepted by the Auction Manager Platform. Any bid outside this limit will be automatically rejected. Default bids can also be specified by users including which auction and time period they apply to.

Allocation of capacity is similar to that used by UK Grid system. If the total number of units for which valid bids have been accepted is lower or equal to available capacity, then all bids are accepted and the marginal price is zero. If bids exceed available capacity then the operator ranks bids in decreasing bid price. When the next highest bid is equal to or greater than the available capacity, this bid price will be the marginal price. The marginal price is used by the secondary market for the resale value of units.

In terms for capacity usage, each user is awarded an Interconnector Capacity Entitlement (ICE). For each hour in the trading day, each unit holder may nominate an energy transmission value up to the limit of its ICE. The sum of unit holders Long Term Nominations and daily ICEs will form its Active Capacity Holdings (ACH). The operator will submit ACH to the Irish TSO for each unit holder prior to the first gate closure.

Capacity transfers can take place across trading periods and in at least one period of one day – the operator will not charge a transaction fee for allocated capacity transfer as the transfer is between trading periods – not users.

The Use It or Sell It (UIOSI) rule ensures the any unused capacity can be made available for other users. Any unit holder who does not nominate long term units associated with its Long Term ICE for any trading period of a trading day will lose the right to use such Long Term Units. These unused units will be made unavailable for future use by the unit holder but is still required to pay the operator for unused units (subject to whether they were acquired in capacity transfer). Unused units are made available in the daily market, and the proceeds of the sale will go to the unit holder. If there is any change to the Net Transmission Capacity, revised unit allocation will be available to unit holders as soon as possible. Unit holders will be credited in full for unit price of curtailed units during the settlement period when metered values are available.

In the case of a fault, or a system intertrip curtailment may be required on the interconnector. In this case, curtailment will be allocated on a pro-rata basis i.e. shared equally across all users in a fair manner [62].

2.5.1.2 BritNed Access Arrangements

The access rules for the British-Netherlands link were published in June 2012 [63] and are similar to the Moyle rules explained above . There will be three types of auction:

- Medium Term
- Day-Ahead
- Intra-day

Explicit auctions concern the auction of capacity only, and these will take place in the medium term and intra-day auctions. Implicit auctions concern the auction of capacity and energy, and will take place in the day-ahead market. The maximum length of contract is one year and participants are able to enter into bilateral contracts with operators.

The regulations allow flexibility in the firmness of connections at the discretion of the operator however all capacity is currently awarded as firm access.

The secondary market allows unrestricted trade of capacity rights. Participants can resell capacity or transfer capacity to another interconnector customer. There will be no administrative charge for this trade by the operators.

All capacity which is not allocated at auction, will 'rollover' to the next auction i.e. capacity which is not allocated during medium term auctions, will be available for auction during the day-ahead auctions etc.

UIOSI is applied to medium-term capacity entitlements. Any capacity which is not nominated to transfer energy will be available on the day-ahead market. This ensures there is no hoarding of capacity by users which would prevent other participants from profiting, but puts the security of supply at risk.

2.5.2 Allocation of Access Rights in Other Commodity Markets

A number of other industries carry out a process of access allocation. These include the UK Rail Network and the GB Gas infrastructure.

2.5.2.1 UK Rail Network Access Rights

Network Rail is the owner and operator of Britain's rail infrastructure. The rail network is split into ten routes which each have a number of training operators within each route zone [64]. This can be compared to the GB electricity system where there transmission system is divided into 14 distribution companies each with their own owner/operators.

The Office of Rail Regulation (ORR) [65] is the independent economic and safety regulator for British railways. The ORR is the rail equivalent of Ofgem. They are responsible for ensuring Network Rail manages the rail network efficiently while meeting the needs of the users. The ORR are responsible for licensing operators of railway assets, setting the terms for access by operators for the network and other railway facilities and enforcing competition law in the rail sector.

Track Access Options (TAO) are outlined in a report produced by ORR in 2008 following a consultation period with the relevant parties [66]. Key aspects of the TAO include:

- Use It Or Lose It (UIOLI) provision
- Buy-Back Access Rights
- Contract length of 15 years
- Weighting of paths according to their importance

The Use It or Lose It (UIOLI) provision ensures network capacity isn't prevented from developing through the retention of unused rights. Access will be granted on the assumption that those applying will invest in the network thus ensuring the network is continuously improving and expanding. UIOLI can be compared to UIOSI applied in the use of interconnector capacities – see Section 2.5.

Buy-Back Access Rights ensured that ORR can buy back access rights where better use of available capacity can be demonstrated. TAOs are granted for a period of 15 years with the first option to buy back access at 10 years. This provision would be difficult to apply to the electricity transmission system as technically, all energy generated on the system can flow through any of the transmission lines.

Tracks are weighted based on importance during particular time periods e.g. weekday AM peak, weekday interpeak, weekday off peak, Saturday and Sunday. A similar weighting method is applied to distribution networks during peak time periods during a 24 hr day. This weighting could be applied to transmission networks on lines which often experience overloading. However, the cost of using the congested line would have to be socialised across the network as individual users could not be determined due to the nature of electricity flows. For this reason, Ofgem would not approve such a method as it may unfairly increase costs to customers.

2.5.2.2 GB Gas Transmission System Access Rights

The supply of gas in Great Britain is managed by the same body that operates and regulates the GB electricity system. National Grid is responsible for ensuring the delivery of gas to end users and Ofgem also acts as regulator to the gas industry. Gas suppliers buy gas from shippers, and sell it on to customers; National Grid is purely responsible for the transport of gas. An overview of the Gas system is shown in Figure 2-9.

Gas is delivered to the UK at one of nine terminals, the gas then enters the National Transmission System (NTS) where it is pushed through the system using compressor stations. The NTS is split into twelve local distribution zones that contain lower pressure pipes to deliver gas to domestic customers. There are three gas pipelines connecting NTS to Belgium, the Netherlands and the Republic of Ireland. [67]

To connect to the GB NTS, there are three distinct steps an applicant must take [68]. These are:

- Applying for a physical connection to NTS
- Signing an Operational Network Entry Agreement (NEA)
- Obtaining sufficient Transmission Entry Capacity

The first two points set out the services provided by national grid to the connection applicant along with the responsibilities for maintenance, operation and control of equipment.

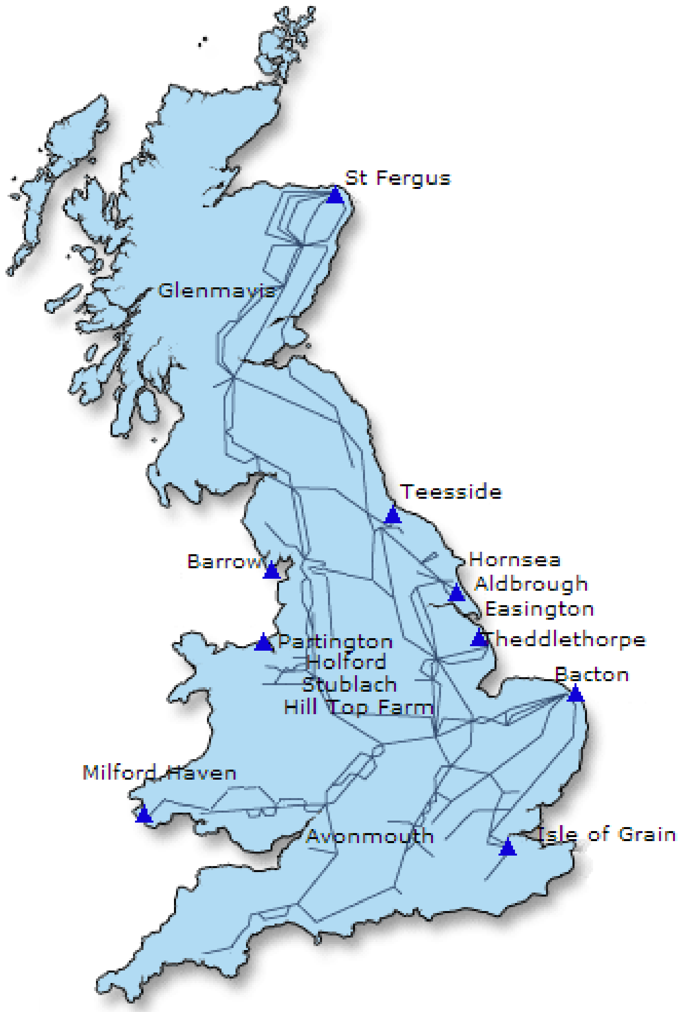

Figure 2-9 GB gas transmission system with entry terminals shown [69]

The Entry Capacity application applies to the Shipper i.e. a party who injects or removes gas from the system. Each Shipper must make sure they have sufficient daily capacity rights to accommodate gas entry flows from the connection point. If there is an increase in the need for capacity, National Grid will respond by upgrading/extending the existing physical infrastructure. This is similar to the way in which the electricity system operated prior to Connect & Manage – applicants are required to wait until relevant upgrades are made to the transmission system before a connection is granted. Unlike electricity, gas can be stored; therefore the gas NTS is not subject to the same constraint issues as the electricity network.

Both rail and gas markets apply similar rules on access to those used by National Grid for the use of Interconnectors. The following section will focus on access rights at distribution network.

2.6 The Cost of Balancing the GB System

National Grid produces monthly reports which provide a detailed breakdown of the costs incurred in balancing the system [70]. This includes the costs of constraints which make up the majority of payments to manage system issues.

It is often reported in the press [71] that wind farms receive particularly large payments to reduce output. This is a result of wind farms submitting high bids indicating their desire to remain connected should a constraint occur. In the majority of cases, the system operator accepts the lowest bid to resolve the constraint, but in some cases the system operator is left with no choice but to curtail the expensive generator. For example, all other generators may have been curtailed and the constraint exists, or the expensive generator is the only generator contributing to a particular constraint. In reality the payments made to wind generators are just a fraction of the total balancing costs as demonstrated by Figure 2-10. The total constraint costs in March 2014 were 42% or £30.6 million of total system balancing cost of £72.92 million.

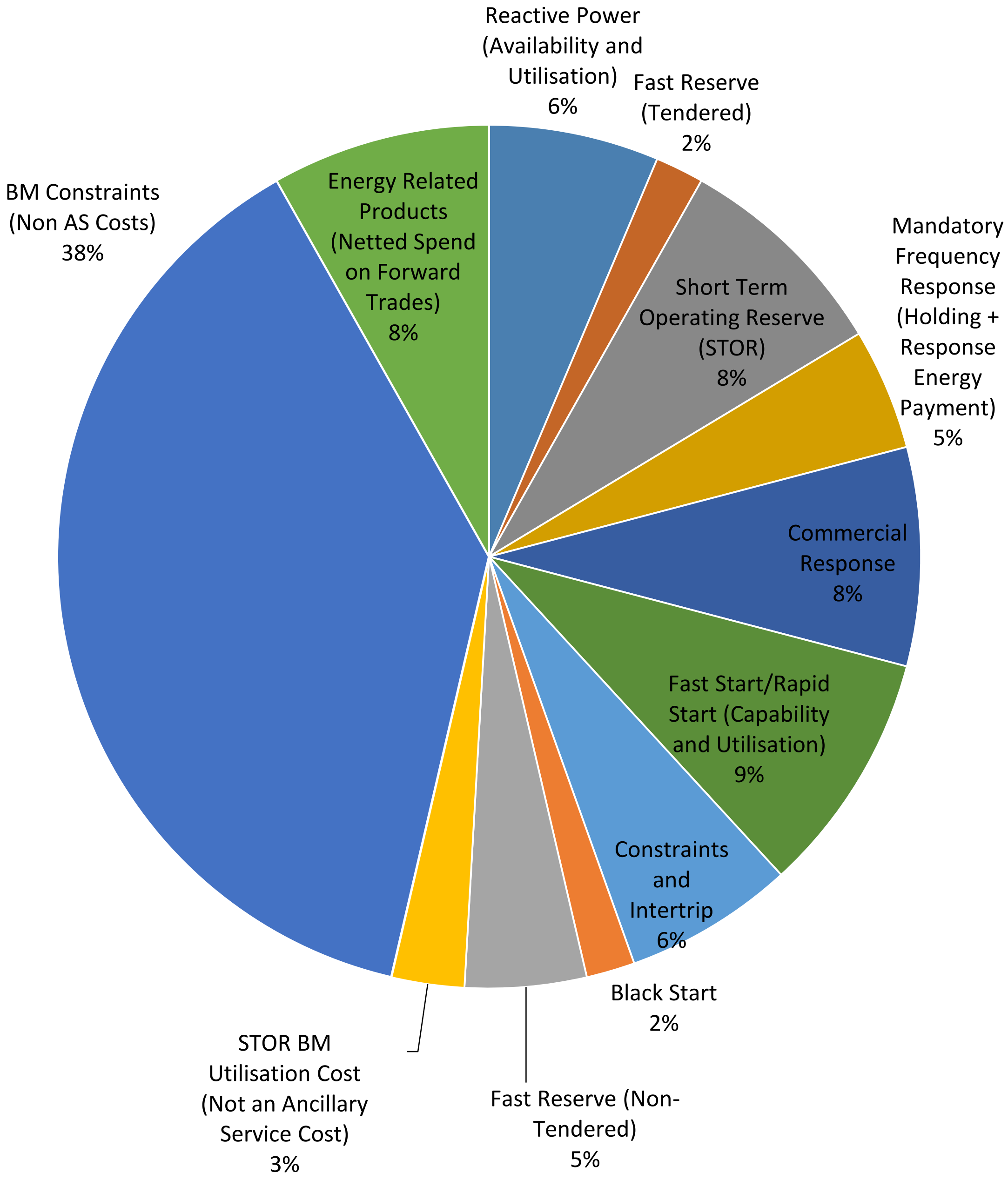

Figure 2-10 Total balancing services costs for March 2014 [72]

For the financial year 2013/14, the breakdown of constraint costs by fuel type are shown in Figure 2-11. Positive values indicate costs to National Grid, while negative values indicate receipts. The 'Other' category includes hydro, OCGT, demand, nuclear and oil generators. The main location of these constraints is the 'Cheviot' boundary, which is the boundary between Scotland and England. While wind farms are paid the most to manage the constraint i.e. curtail energy, the system operator then must pay other generators to balance the system i.e. find another route through the system to meet demand.

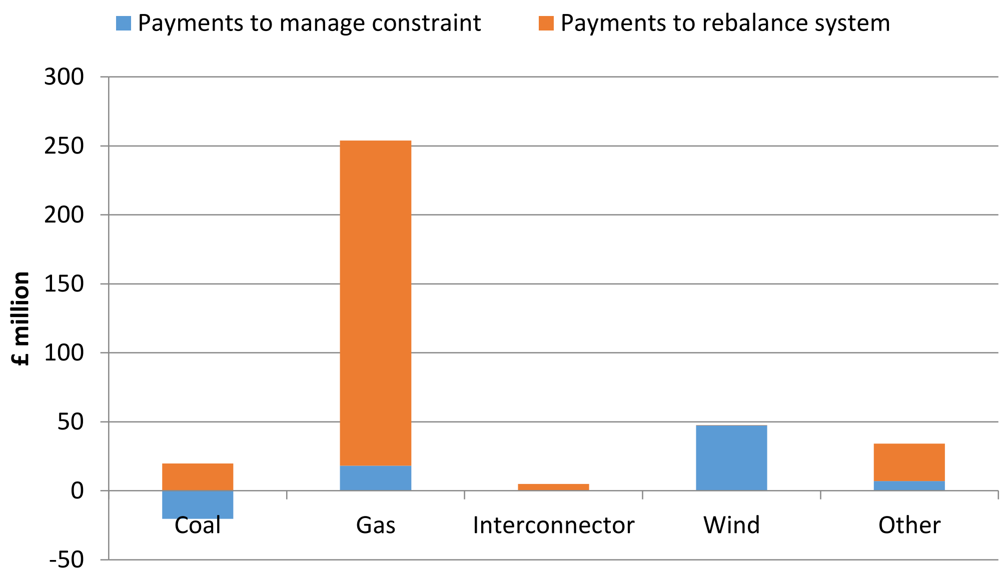

Figure 2-11 Constraint costs for the financial year 2013/14 [72]

In Figure 2-12, the payments made to gas and wind farms for the first 4 months of 2014 are compared. It is a common misconception for the public to believe that only wind is paid to reduce output, but in April 2014, gas generation was paid more than wind farms to reduce output. The total costs of constraints in April 2014 was £10.6 million.

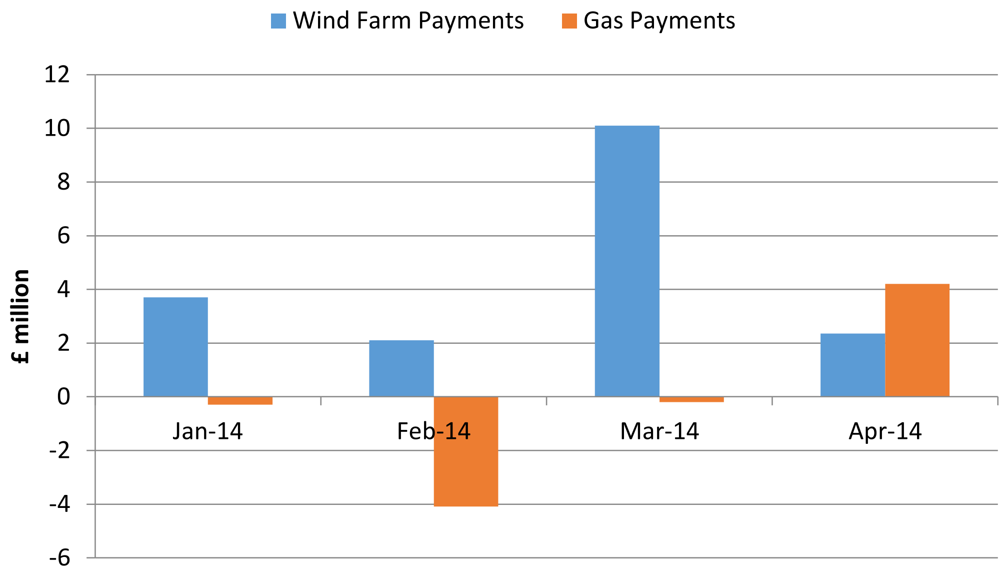

Figure 2-12 Payments made to wind farms and gas plants to reduce output [70]

2.7 Distribution Networks and the Advent of Active Network Management Schemes

Many of the areas discussed in the previous sections lead on naturally to a discussion of ANM schemes. The climate change problem has led to an increase in renewables connecting at distribution level. Regulation of networks is driving innovation forward, markets require dispatch and trading, balancing requires alteration of output, and congestion is the inevitable result of a finite network. All of these issues either create or have some bearing on ANM.

Funding initiatives developed by Ofgem (discussed in 2.3.4) signalled the beginning of ANM schemes. Distribution networks were moving away from the traditional 'passive' model of network operation, and as more distributed generation was connected the network operators were required to develop new solutions which led to 'active' management of the network.

ANM can be defined as the use of IT, automation and control to manage grid constraints associated with the integration of distributed generation. ANM can be used to manage energy producing or consuming devices to resolve network constraints on both transmission and distribution systems.

ANM first emerged in the UK through the work of the Embedded Generation Working Group (EGWG), which later became the Distributed Generation Coordination Group (DGCG). Their report on network access issues in 2001 [73] set a number of changes to distribution network operation in motion as the response from Ofgem explains in further detail [74].

The Register of Active Network Management Pilots, Trials, Research, Development and Demonstration Activities was published in 2008 [67] and lists all projects related to ANM systems, from research projects through to full scale deployment.

Of the 121 projects listed in the register, 69% were at the research and development phase; however an increasing number of projects were moving towards the trial and pilot stages when compared with the previous register published in 2006.

The accompanying project report [68] highlights the strong lead in Voltage Control and Power Flow Management systems as these are seen as the key issues holding back the connection of more distributed generation. Schemes such as these have already been deployed in a number of locations around the UK.

Communication systems are an essential part of any actively managed system. A number of projects listed in the register suggest that current SCADA systems could be improved upon to facilitate DG in networks. However new communication and control systems are still being researched.

The following projects were funded from the funding initiatives discussed in 2.3.4 and have implemented ANM solutions and in particular apply some form of curtailment scheme for distributed generation.

2.7.1 Orkney Active Network Management Scheme

Established by Scottish and Southern Power Distribution (SSEPD) as part of RPZ funding, The ANM scheme on the Orkney Islands is the first of its kind in the UK. A number of papers [7], [75]–[78] have detailed the research and development and deployment of the Orkney ANM scheme and the project is currently in the second phase of development utilising further incentive funding from Ofgem. The scheme was created in order to facilitate the connection of wind generation to the network. By utilising ANM technologies, a further 18 MW of non-firm wind has been connected to the network. with plans for a further 5 MW to be connected in the future [41].

The current mix of generation on Orkney consists of:

- 10 MW gas turbine at Flotta

- 16 MW back up diesel generator at Kirkwall (Only used in emergency situations)
- 7 MW wave generator at Stromness
- 4 MW wave and tidal test centre
- 42 MW of wind generation in total (turbine sizes range between 0.9 MW to 2.75 MW machines)

The Orkney system uses a 'connect and manage' approach, similar to that implemented at transmission level. There are three classifications of connection agreement for generators connecting to the Orkney network [76]. These are:

- Firm Generation (FG)
- Non-Firm Generation (NFG)
- New Non-Firm Generation (NNFG)

FG is able to run at rated output at all times including during outages of N-1 contingency. NFG is allowed to run at rated output during normal conditions but a hardwired trip will activate during fault conditions e.g. such as the loss of one of the subsea cables. NNFG are subjected to a Trim/Trip approach developed by Currie et al [71]. NNFG will be curtailed during periods of low demand or high wind i.e. when there is simply not enough capacity on the network for the generators to contribute their output.

When curtailment is required, the ANM controllers will send trim/trip signals to generators behind the constraint in the order determined by the priority stack [75]. The last generator to connect to the network will be the first to be asked to curtail during a constrained period. Generators at the bottom of the stack will be first to curtail. This curtailment method is referred to as 'Last in First Off' (LIFO) and is discussed in further detail in Chapter Three. The network is divided into 'constraint zones' with each zonal boundary being a constraint point, as shown in Figure 1. The intent is that Zones 1-4 are controlled and the core remains passive.

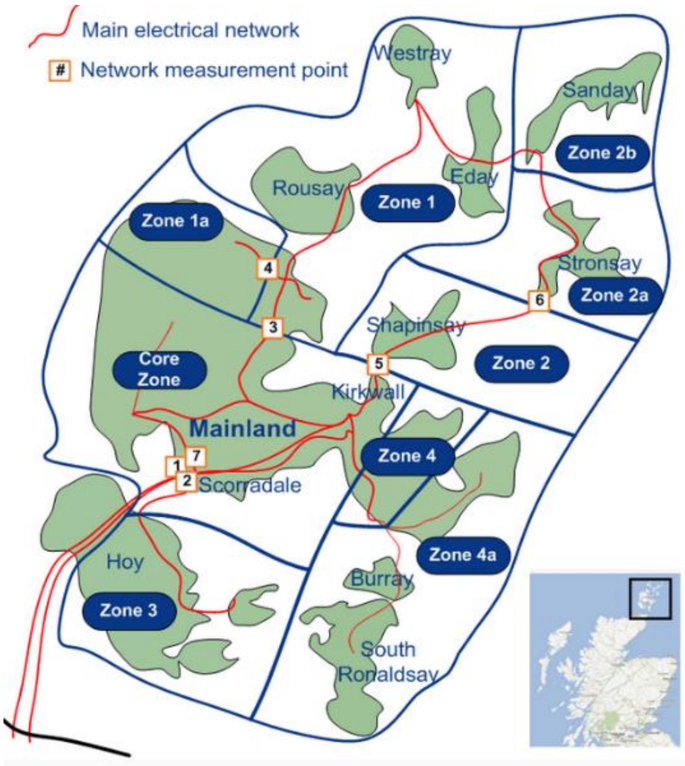

Figure 2-13 Orkney distribution network with zone boundaries [79]

The system is managed in real-time via the use of a programmable logic controller, which receives measurements of power and current, and uses private or public radio links to communicate commands to generators. This system has been developed by Smarter Grid Solutions Ltd. In addition to ANM solutions, several reactive compensation devices and shunt reactors have been installed to resolve local voltage rise problems at specific locations on the Orkney network.

A report produced by KEMA [80] on the Orkney ANM scheme highlights the project successes and problems encountered during the creation of the ANM scheme. Generation developers remained interested in connecting to ANM scheme regardless of projected curtailment figures, most likely due to high capacity factors available when compared with mainland GB.

The Orkney ANM project was implemented as an alternative solution to network reinforcements and cost approximately £500,000. Traditional reinforcements would have been in the form of a new 33 kV subsea cable linking Orkney to mainland GB grid, which would have cost an estimated £30 million. Regardless of the construction of the subsea cable, there would still be local constraints on the network which would require some form of constraint management of exporting generation. From inception as a research project, the

Orkney ANM scheme took six years to reach operational stage (2003 to 2009). This lengthy period was the result of advanced modelling required for generators, extensive testing, technology development and external factors such as planning consent and construction work for the first generators.

The Orkney ANM scheme is based on a locally centralised architecture with network and generation output measurements communicated back to a central processing unit sited at the operational hub for the Orkney power network. Control instructions are calculated there and communicated out to controlled generating units. The necessary SCADA and Distribution Management System interfaces, communications links with watchdogs and local fail-safes are integral to this architecture.

One of the early lessons learned from the Orkney ANM Scheme was the importance of communication systems. The communications for each curtailable site was the responsibility of the generator. There were problems with generators who used existing lower frequency radio links or a leased copper wire medium. When the communication links between generators and network are down the generators are automatically issued a zero set-point to prevent any network problems i.e. they are set to 0 MW output. As a result of initial unreliability of some of the communication links, there were higher levels of curtailment for some generators.

Further lessons learned involved the inclusion of micro-scale wind generation in the Orkney ANM scheme. Only wind generation greater than 50 kW was installed with monitoring and communication equipment required for curtailment instructions from the ANM scheme. While this was justified from a financial viewpoint i.e. the smaller generators had less funds available to pay the cost of installing monitoring and communications equipment, this has resulted in a large volume of micro-generation eating in to the capacity of larger generators in the LIFO stack. The second generation ANM controls for Orkney will include control of micro-generation amongst other additions [41].

The Orkney Storage Park is funded through LCNF, and phase 1 of the project was completed in 2012 [81]. The 2 MW battery has been installed on the network and is owned and operated by a 3rd party Energy Storage Provider (ESP). SSEPD have created new commercial arrangements for the ESP similar to those offered at transmission level for the provision of ancillary services. The storage device is paid a utilisation payment when it is used to store excess capacity and a nominal availability payment is granted when the battery is full and the network is still constrained. The ESP is then paid a further utilisation payment when it is discharged. The official opening of the storage park took place in August 2013. [82]

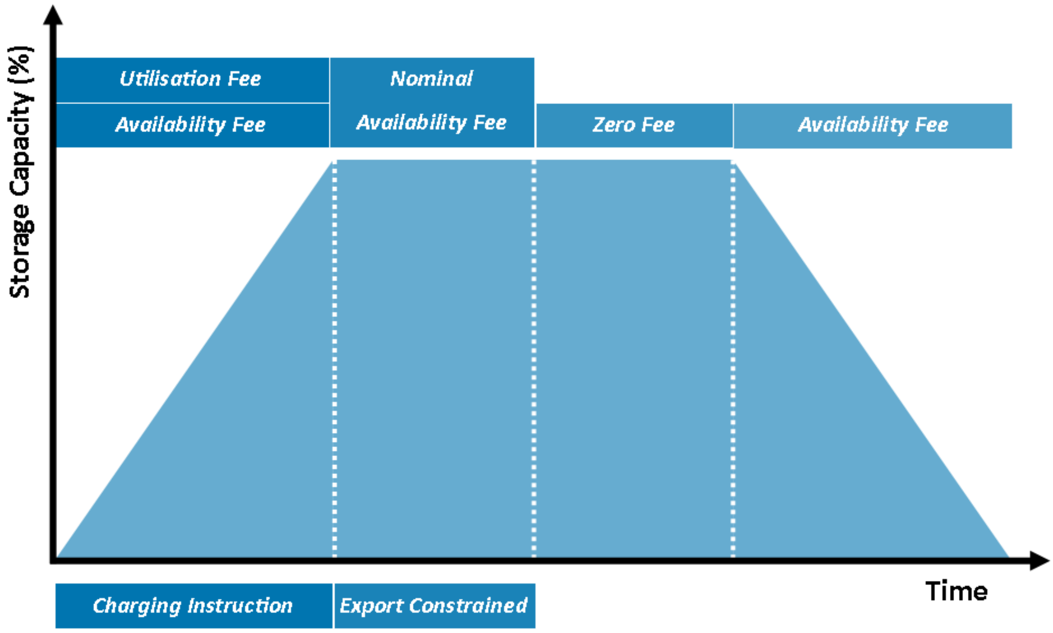

Figure 2-14 Demonstration of battery contract payments

2.7.2 Northern Isles New Energy Solutions

Funded by LCNF, SSE and Strathclyde University, the Northern Isles New Energy Solutions (NINES) project is researching ways to increase and optimise the amount of renewable energy flowing on the Shetland island network and reduce dependence on the conventional generation which is currently the main source of electricity on the island [2]. Better management of the Shetland network, through demand side management and ANM systems will allow an increase in the level of renewable energy able to connect and decrease the volume of fuel burned by conventional generation on the island.

Key aspects of the project include:

- Replacing inefficient storage heaters in 1000 homes with new, efficient models which can be used to balance the system
- New mechanism to reward owners of new storage heating systems
- New commercial arrangements to aid small generators connecting the system
- New systems to manage the network effectively to allow more low carbon energy to be connected

- Construction of a new conventional power plant to replace the existing Lerwick Power Station

The electricity network in the Shetland Isles is composed of three 33kV circuits connecting three large scale generating sites and outward to primary substations supplying demand at 11kV and LV. The Shetland network is not connected to the mainland UK Grid. A schematic of the network is shown in Figure 2-15. A number of network issues have thus far prevented more than 3.6 MW of wind connecting to the network. [83]

There are three main generation points on Shetland:

- Diesel Generation at Lerwick composed of 12 units of varying size, totalling 65 MW
- Gas Turbine at Sullom Voe Terminal (SVT) which is limited to a maximum of 22 MW in winter and 18 MW in summer
- 3.6 MW wind farm connected at Burradale

The island demand ranges from 50 MW to 14 MW. However, 95% of the year the demand is between 16-17 MW. [84]

The NINES scheme will operate a LIFO arrangement for the curtailment of all non-firm generation connecting to the system, similar to the Orkney ANM scheme. Micro-generation will be included in the ANM scheme, therefore avoiding issues experienced by the Orkney ANM scheme, discussed in Section 2.6.1.

Due to the island nature of the Shetland network, the ANM scheme must take account of additional network constraints [8]:

- Lerwick power station must provide a minimum of 40% of the demand at all times to ensure voltage levels remain within acceptable limits
- The frequency of the network must remain within 2% of the nominal level of 50 Hz
- There must be sufficient spinning reserve to cover the sudden loss of wind generation on the network

These three limits are combined to establish the network constraint rules. To determine the maximum allowable wind generation on the system, power flow calculations and dynamic modelling were carried out. Two scenarios were assessed: the loss of all wind generators, and the loss of the largest demand feeder. By ensuring the network stayed within the constraint limits outlined above, a new maximum capacity of 9.62 MW from intermittent sources could be accommodated on the network. Further details of the modelling work can be seen in a paper by Dolan et al. [85]

The funding awarded for the NINES scheme is estimated to be around £33.54 million [86] and this cost covers the creation of an ANM scheme, domestic demand side management, a district heating system and a 6 MWh battery. Network reinforcement solutions which would require the construction of a subsea cable to connect to the mainland GB network would cost in the region of £300 million. [87]

At the time of writing, the Shetland energy system was subject to a consultation regarding the future elements of the system, and in particular the replacement for the existing oil powered conventional generator on the island. The results of this consultation were published in the first quarter in 2015, and a competitive tender process is currently underway [88]. The future of the Shetland energy system, and the ANM system which is already in place may provide a precedent for future ANM systems.

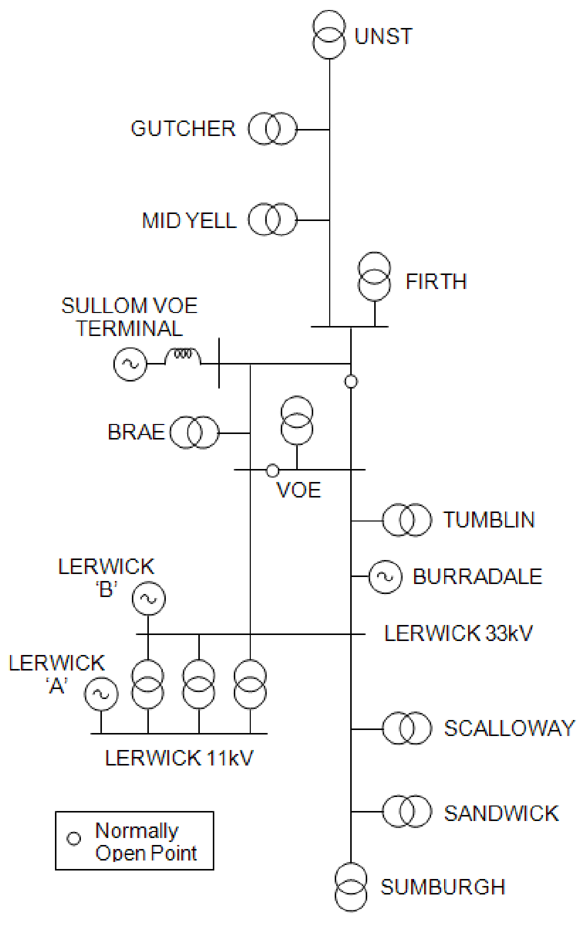

Figure 2-15 Shetland 33kV network [77]

2.7.3 Flexible Plug and Play

The Flexible Plug and Play (FPP) project conducted by UK Power Networks is one of the Tier Two LCNF projects awarded funding in 2012 [89]. It is trialling new commercial solutions for connection of renewable generators. Through the introduction of ANM technologies and innovative commercial arrangements, UK Power Networks hope to fast-track the connection of renewable generation and reduce the cost of connections. The alternative solution is a lengthy delay while network reinforcements are carried out or a high connection cost to generators in order to connect at a neighbouring grid connection point or at a higher voltage level. The network constraint is in the form of a reverse power flow limit at the transformer. There is a peak demand of 42/64 MW in summer and winter respectively and there is 34.5 MW of generation connected to the network. A simplified network diagram is shown in Figure 2-16. As demonstrated by the red dots, there are a large number of generators planned for the future and in order to accommodate them, the constraint must be managed.

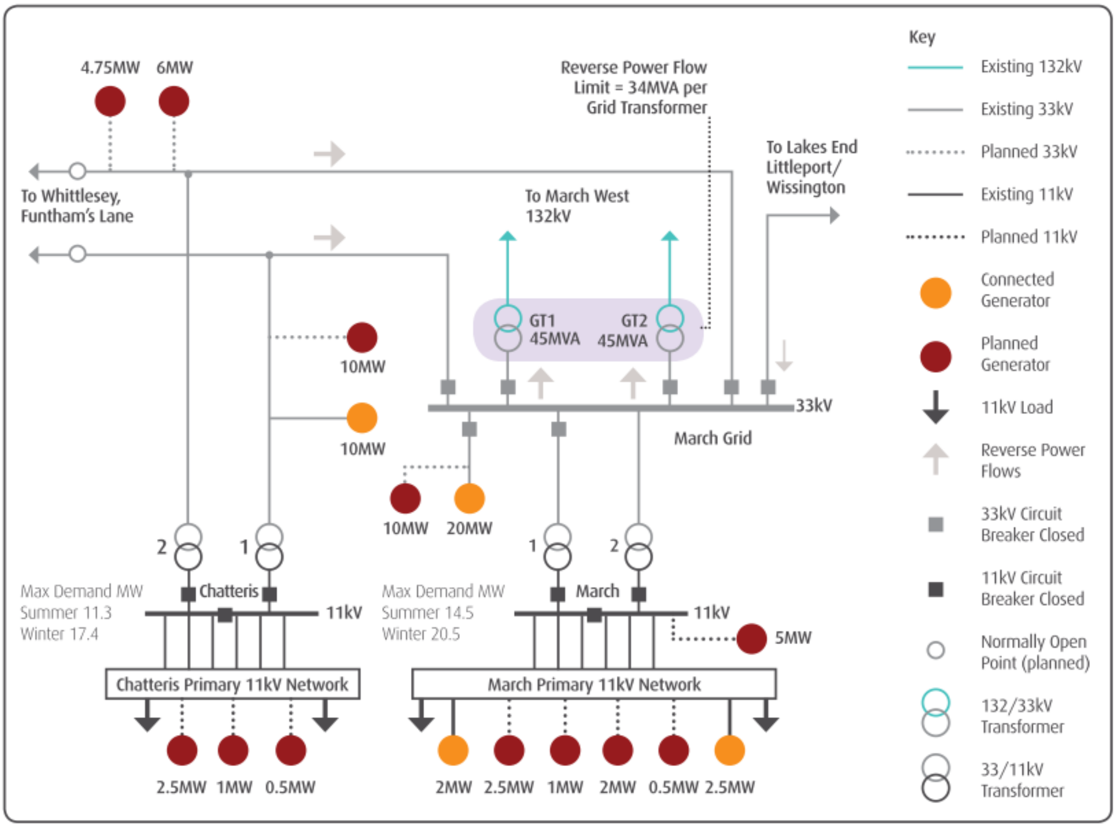

Figure 2-16 Simplified diagram of March grid [10]

A comparison of connection costs is shown in Table 1. Significant savings are shown for generators wishing to connect to the network by introducing the non-firm connection option under the FPP scheme.

Figure 2-17 Table of traditional connection costs compared with ANM connection costs [90]

Project	Capacity	BAU connection offer	FPP Budget Estimate	Savings (%)	Status
Gen A	5 MW	£1.2 m	£570 k	53%	Accepted FPP Opt In Offer
Gen B	0.5 MW	£1.9 m	£400 k	79%	Accepted FPP Opt In Offer
Gen C	10 MW	£4.8 m	£500 k	90%	Accepted FPP Opt In Offer
Gen D	7.2 MW	£3.5 m	£700 k	80%	Accepted FPP Opt In Offer
Gen E	2.5 MW	£1.9 m	£170 k	91%	Accepted FPP Opt In Offer
Gen F	1 MW	£2 m	£300 k	85%	Pending

Curtailment of non-firm generation is shared equally across all generators during a constraint. This is referred to as pro-rata curtailment and is discussed in more detail in Chapter Three. UK Power Networks and Baringa carried out some analysis and determined that a Pro-Rata arrangement provided higher long term capacity factors for generators when compared with a LIFO arrangement. A cap was set on the maximum capacity which could connect under a pro-rata arrangement. Once this cap is reached, LIFO will be applied to any subsequently connecting generation.

In addition to the trial of smart commercial arrangements, the FPP trial is using smart devices. This includes a tap changing transformer, or a quadrature booster to manage the imbalance of thermal load in double circuits. This technology controls the phase angles of the voltages on one of the lines in order to change the distribution of power flow through the double circuit. Quadrature boosters have been in regular use by National Grid since the 1970's but UK Power Networks is now using this transformer technology to reduce constraints on parallel lines. [91]

The cost of the FPP ANM scheme is approx. £6.7 million (total funding awarded by Ofgem) which compares to reinforcement costs i.e. upgrading the transformer, of £15.3 million [90]. One consideration for the future of the network is that as the level of connected non-firm generation increases, thermal constraints could be created in some areas of the network. In this case, new curtailment zones are created. At the present time, curtailment is based around a constraint at the grid connection point. Connection agreements with generators will have this constraint written in to the contract. With new constraint locations, the question arises as to how curtailment might be allocated and if capacity factors might be reduced to a value lower than previously guaranteed by the DNO. This refers to issues regarding the level, to which DNO must guarantee certain capacity factors in ANM schemes, and should a level be exceeded then what level of compensation should be provided.

2.7.4 Accelerating Renewable Connections

Scottish Power Energy Networks were awarded £8 million funding for their Accelerating Renewable Connections (ARC) project as part of Second Tier LCNF.

The project is a collaboration between SP Energy Networks, Community Energy Scotland, Smarter Grid Solutions and the University of Strathclyde. The project aims to facilitate the connection of renewable generators in the south east of Scotland. The Active Network Management scheme will cover an area of 2,700 square kilometres, and five individual distribution networks each with different issues. The key objectives of the project are to improve network access, speed up time taken to grant connections, and enable the connection of generation to constrained networks.

In one of the constrained networks, the constraint occurs at the Grid Supply Point (GSP). This requires close discussions with National Grid as the management of this constraint will impact on wider system balance [92]. For the local network constraints, a LIFO arrangement will be used. The visibility of the ANM-enabled GSP will allow the TSO to determine more accurately the behaviour of generation at distribution level. [93]

A further objective of the project is to empower customers, and SP Energy Networks have done so by producing connection ‘heat maps’. This allows developers to view where there is available capacity on the network and therefore inform where the faster and cheaper connection locations may be [94]. A heat map is shown below in Figure 2-18. Green areas are available for connection applications, light blue areas have some constraints but connections may still be granted. Dark blue areas have substantial constraints and connections are unlikely without extensive network upgrades [95]. The other 5 DNOs have also produced similar styled maps as part of their Long Term Delivery Statement (LTDS).

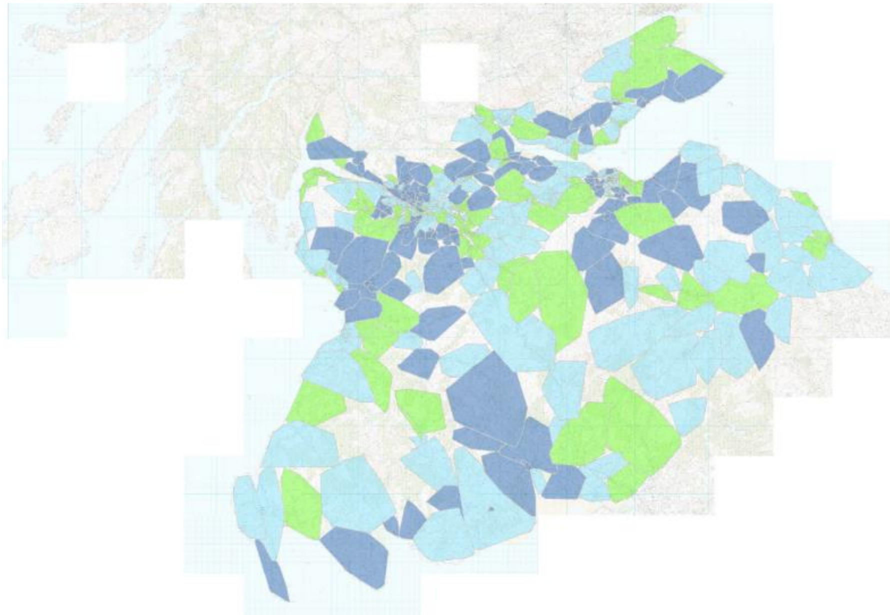

Figure 2-18 Scottish Power Distribution Networks heat map [94]

2.7.5 Lincolnshire Low Carbon Hub (LLCH)

Western Power Distribution (WPD) was awarded £3 million of Tier 2 LCNF in December 2010 to allow them to improve and facilitate the connection of renewable energy projects to the distribution network [96]. The project includes a number of innovative network techniques including:

- Dynamic Line Rating
- Dynamic Voltage Control
- Commercial Arrangements
- 33kV active network ring
- Flexible AC Transmission System (FACTs) Devices

WPD have adopted a LIFO approach for constraint management on the LLCH. Engage Consulting researched a number of options and built upon the work already carried out by UKPN's FPP project [90]. It is not clear from the project report why LIFO was selected as the PoA however the report does state that LIFO was the "most appropriate and fairest solution for customers wanting to connect."

The charging methodology used for non-firm connections are based on customers funding the constraint management scheme and not any traditional reinforcement that may be required in the future. This methodology will result in a limit to the number of generations who can connect to the network without some network upgrades. Non-firm connections will be offered to generators alongside standard connection offers.

Figure 2-19 Lincolnshire Low Carbon Hub [96]

WPD have developed an online tool [42] to allow generation developers to appreciate the impact of curtailment on their generator output. This aids in the calculation of project viability. In addition to this, WPD have developed a spreadsheet tool to help network planners to calculate constraints in the current network, and constraints for future demand levels.

The LLCH project also features elements of dynamic control. The increasing connection of renewable energy generators will have an impact on the voltage and power levels in the network.

The primary network voltage is regulated through the use of relays, ensuring that the voltage stays within limits at all times. Similarly, Dynamic Line Ratings (DLRs) which were installed as part of the Skegness RPZ project are to be further developed in order to determine better techniques for calculating plant and equipment ratings and in turn, real time operating limits.

More details on other aspects of the project can be found in the six month progress report. [97]

2.7.6 Other Examples of ANM Schemes in Europe

The following projects are example of 'smart grid' projects from Europe. Currently, the UK ANM projects are leading the way in terms of applying new commercial arrangements for curtailment, however these other examples demonstrate other elements of smart grids which have yet to be trialled in the UK.

2.7.6.1 FENIX Project: Flexible Electricity Networks to Integrate the Expected Energy Evolution

The FENIX Project is a European Technology Platform funded project [98]. The aim of the project was to develop new methods of operation for Distribution Networks driven by the following issues:

- Deregulation of electricity markets resulting in new cost reduction targets and better quality service
- The introduction of distribution generation and storage devices in distribution networks
- New connection methods allowing control of reactive power and voltage
- The desire to allow flexibility for energy consumption

The main output of this project was the development of a Virtual Power Plant (VPP) concept, and development of the commercial and regulatory framework that would allow the integration of a VPP in to a future European power system. Large scale trials were undertaken on real networks in Spain and the UK.

The purpose of a VPP is to represent a number of Distributed Energy Resources (DER) as one generator in order to behave in a similar way to large scale conventional generation. The outline of the VPP system is shown in the Figure 2-20.

By aggregating the properties of a mix of DER (e.g. Wind, Hydro, Tidal, CHP and storage) the VPP can be used to make contracts in the wholesale market and offer services to the system operator such as system balancing and ancillary services. Further information regarding the demonstration projects can be found in the FENIX technical brochure [98].

Other work on VPP systems [99], [100] highlights the benefits that VPPs can have in future energy markets. By grouping portfolios of different renewable DG together, they can be optimised to meet demand in an actively management distribution system.

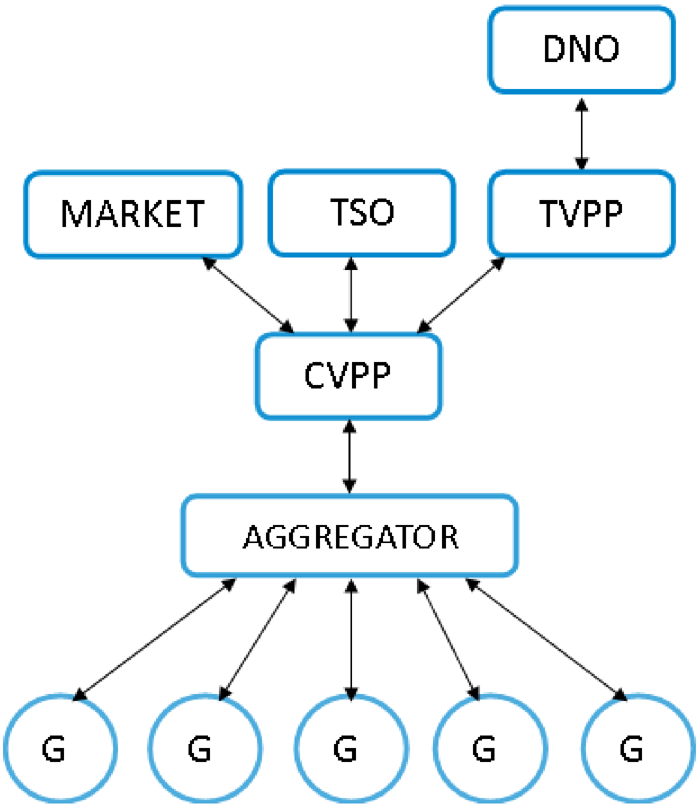

Figure 2-20 Diagram illustrating the operation of a VPP

2.7.6.2 EU EcoGrid

The EU Eco-Grid project [101] is a large scale demonstration of smart technologies on the island of Bornholm in Denmark. It is part of the Nordic Power System and the distribution network is owned and operated by the Bornholm community.

Key elements of the project include:

- A broad mix of renewable DG including 36WM wind generation, 16 MW CHP, 2 MW PV, 2 MW biogas and 5 district heating plants
- Use of Electric vehicles and CHP units
- The development of a real-time market
- The development of new information architecture allowing all DG and consumer demand response units to participate in the power market
- The use of smart appliances, smart meters and energy storage (including electric vehicles being utilised for storage

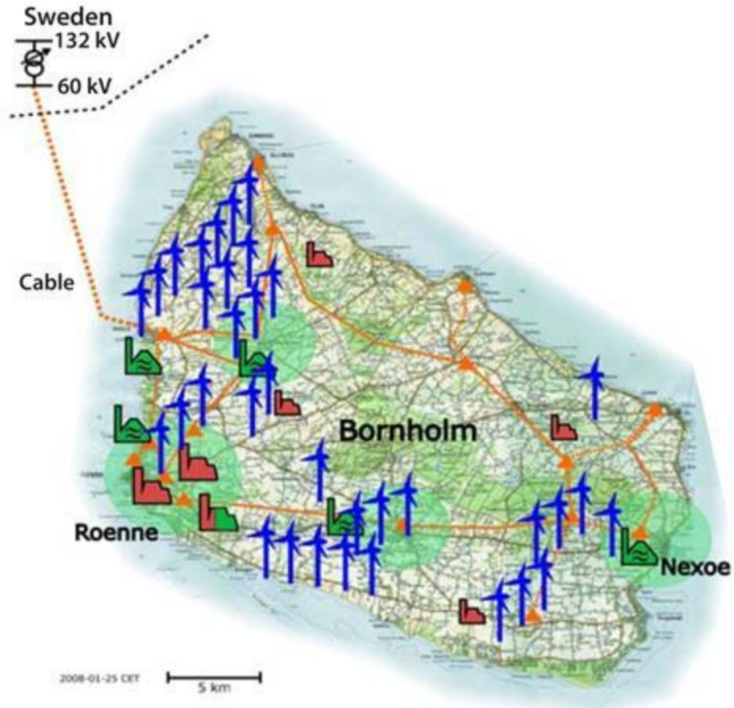

Figure 2-21 Diagram of Bornholm Smart Grid project [101]

Customers will be fitted with smart meters that will allow them to manually adjust energy use in their homes, or set the meters to automatically control energy use based on real time pricing. More details of the real time pricing market and customer smart grids can be found in the project report. [102]

2.8 Conclusions

Legislation at EU and UK levels has provided the stimulus and incentive to develop renewables, and in particular the increase in connection of wind generators, but there are three sets of issues which can sometimes restrict the connection of renewable generation to the power system. These include:

- Market issues such as subsidies, compensation for curtailment, use of system charging and electricity pricing (discussed in Section 2.1-2.3)
- System issues (discussed in Section 2.4 – 2.6) which can include security of supply, back up reserve and system balancing. Systems which are overloaded with new generation may have difficulty in balancing generation and demand
- Network issues which focus on local aspects such as lack of capacity on the network to enable new connections (discussed in Section 2.7), and also control of voltage and reactive power levels on the network

At transmission level, the Connect and Manage scheme has allowed generation to connect without having to wait for wider network reinforcements. Examples of the management of constraints from other transmission networks across the world has demonstrated that there are many methods that can be used, primarily generation curtailment, in order to allow an increase in the number of renewables connecting to the network.

The introduction of ANM schemes at distribution level has allowed distribution networks to operate in a manner similar to transmission networks – with active management of power flow and voltage levels, as opposed to the more typical passive operation method. This enables distribution networks to offer reduced connection costs to renewable generators in exchange for some reduction in output during times when the network is at capacity.

The case studies presented in this chapter demonstrate the ability of ANM schemes to facilitate the connection of wind and other renewable generators at distribution level. All schemes demonstrate innovative tools, technology and commercial arrangements to manage constraints. The rules of curtailment i.e. the PoA, are still in the very early stages of development with many DNOs opting for the quicker and easier solution in order to implement schemes with-in the time limits set by funding conditions and within current regulatory frameworks.

Chapter three will elaborate on different options for PoA, and discuss ways in which these can be compared against each other and the advantages and disadvantages of each principle discussed. The development of ANM schemes is still very much in the initial stages, and full exploration of alternative PoA to those already implemented has still to be explored. The presentation of a number of different options for PoA will allow this thesis to qualitatively and quantitatively analyse each arrangement and provide a discussion which will be a significant contribution to the research area.

3 Evaluation of Principles of Access and Modelling Techniques

3.1 Chapter Summary

The previous chapter highlighted that the issue of network access is of key concern to the users of any system and that the PoA will play an important role in the future of ANM schemes. The number of ANM schemes in the UK is growing rapidly, and non-firm connections are now being included as a standard option in connection offers. Network access refers to the connection of generators to the network and the operation of generators once they are connected. It encompasses the timing and cost of the connection, and the curtailment and compensation of the generator.

This chapter begins with a discussion of alternative PoA. These arrangements form an important part of the connection arrangement as they can determine the volume and frequency of curtailment for a generator connected under a non-firm arrangement. To date only two forms of PoA have been trialled in the UK; therefore it is important to highlight other alternatives in order to determine if there are more suitable arrangements for PoA. The exploration of alternative PoA should not be limited to the technology that is currently operating, but should provide suggestions of what might be possible in future ANM trials.

The arrangements are divided into two groups: market and non-market. Each PoA is qualitatively analysed using assessment criteria which has been used previously by other authors to discuss other commercial and regulatory issues. A matrix analysis is used to compare different arrangements and a conclusion is reached regarding which PoA are to be taken forward for quantitative analysis.

The chapter then goes on to discuss elements of electricity market and auction design which is relevant to the design of market based PoA. This will help to create a market based PoA which can then be assessed alongside the other non-market PoA and a comparison made.

The chapter concludes with a discussion of power system evaluation techniques, before the review focuses in on the use of OPF methods and its application to constraint management and distribution network planning. This review will present an outline of methods which will be used to qualitatively analyse a number of PoA in later chapters.

3.2 Principles of Access

There are a number of schemes operating PoA in ANM schemes in the UK. A 'Last In First Off' or LIFO, approach is favoured by the majority of schemes, with only one scheme currently operating with a Pro Rata curtailment approach. Currie et al present a comparison of PoA in [9]. This paper defines the term Principle of Access as the rules which determine the curtailment order of generation in ANM schemes and gives a qualitative discussion of a number of PoA. Similarly, UK Power Networks carried out analysis of alternative PoA in [10] as part of their Flexible Plug and Play project.

This section will begin by providing an assessment criteria against which all PoA can be compared, before going on to discuss a number of PoA and finally determining which PoA will be modelled on a real network case study example.

3.2.1 Assessment Criteria

In order to compare the merit of different options for PoA, assessment criteria must be established. Examples of criteria used in other assessments of regulatory rules can be found in [9], [10], [101], and [102].

The Assessment Criteria are outlined below. All new commercial arrangements must:

1. Comply with all UK Grid Code requirements
2. Support safe, secure and reliable power system
3. Support efficient network operation
4. Be clear and transparent
5. Be flexible to suit future network scenarios
6. Gain support of all stakeholders
7. Be simple to implement
8. Be robust
9. Allow generators to be able to estimate future annual outputs in order to secure investment from financial backers

The explanation behind these criteria is outlined below.

Comply with UK Grid Codes

The UK Grid Codes are designed to permit the "development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity, to facilitate competition in the generation and supply of electricity and to promote the security and efficient of the power system as a whole" [105]. The Grid Code is required to cover all technical and operational aspects of connection to and use of the transmission or distribution system. The codes also specify which information or data users connected to the system are required to provide to National Grid for planning and operational use. All PoA must comply with these codes in full.

Support a safe, secure and reliable power system

All new PoA should allow the network operator to alter levels of generation as and when required. This will ensure a safe, secure and reliable power system, and aid the transmission or distribution system in its own safe, secure and reliable operation.

Support efficient network operation

All PoA should support the most efficient network operation i.e. minimal loses on the network, and the optimal operating arrangement for the network.

Be clear and transparent

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

Be flexible to suit future network scenarios

As more distributed generation connects to the networks, the behaviour on the network may change. Any PoA which are applied must be flexible enough to accommodate any changes in behaviour and operation while still ensuring safe, efficient operation and remaining clear and transparent for all users.

Gain support of all stakeholders

Any changes to PoA will affect a number of different stakeholders in different ways. Any suggested change which will have an overall negative effect will be met with resistance from the stakeholder groups. It is possible to include the 'grandfathering' of rights where some temporary compensation is given to those who would rather remain with existing arrangements while allowing progression towards a new and better arrangement for the majority involved.

Be simple to implement

The arrangements should be easy to understand for all participants, but not so simple as to ignore key considerations required in network charging and access.

Be Robust

The arrangements must be robust in order to prevent game playing on the network, in particular – game playing of larger generators who could exploit the market and take advantage over having more capability in a market environment when compared with smaller, community owned generation.

Allow generators to be able to estimate future annual outputs

All PoA must ensure bankability. Investors cannot back generator investment unless there is certainty in the future profit of the generator. Any change in commercial arrangements could have a significant impact on generator profit e.g. a generator who is currently high on the priority list in a LIFO arrangement i.e. last to curtail will see an increase in curtailment if the DNO moves towards a shared arrangement where all generators are curtailed on a pro-rata basis.

3.2.2 Qualitative Discussion of Principles of Access

In order to better quantify different PoA, they will be split in to two categories – market and non-market arrangements. These categories reflect the amount of control generators have over their own curtailment. In non-market arrangements 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.

The different PoA are discussed below, and their properties qualitatively assessed against the criteria discussed in 3.2.1. The list of PoA presented in Figure 3-1 was taken from an existing literature review by Currie et al [9].

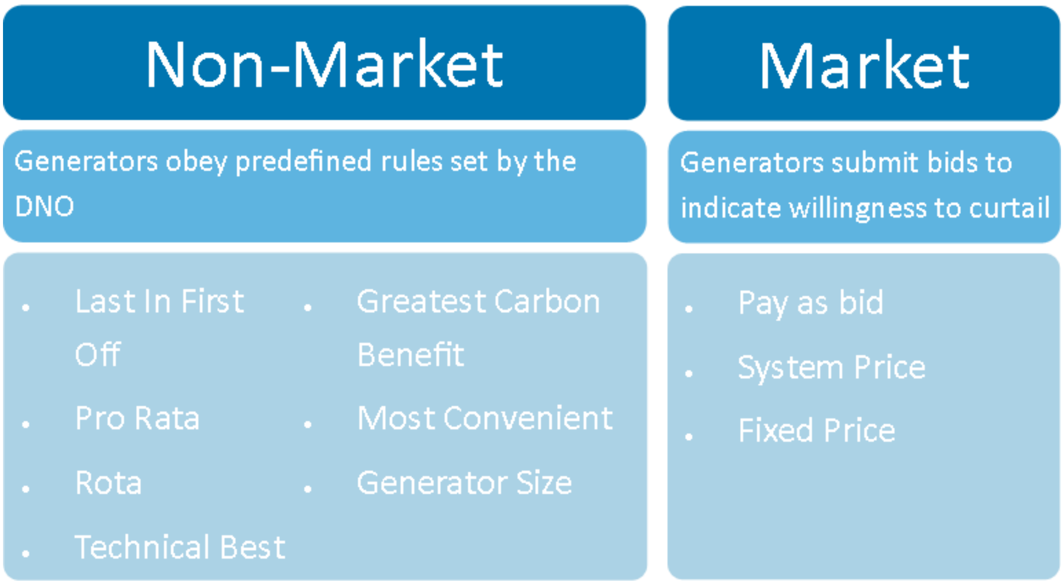

Figure 3-1 Market and non-market arrangements

3.2.2.1 Non-market Principles of Access

Non-market arrangements use pre-defined rules set by the system operator to determine the curtailment of non-firm generation. Generators are aware of these rules when the connection agreement is signed, and must adhere to these rules in order to be granted a connection. Non-market arrangements are currently applied in several ANM projects in the UK and they can be implemented without any significant changes to network regulatory framework.

Last In First Off (LIFO)

This method curtails generation based on the date of connection i.e. the last generator to connect to the network will be the first generator to curtail. Adding a new generator connection 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. This approach is consistent and easier to implement with the current regulations when compared with other arrangements. However, this method is not necessarily the best way of operating the network and as network limits are approached, new generators may be discouraged from connecting.

Pro Rata

The Pro Rata method divides the required curtailment equally between all generators contributing to the constraint. The total amount of curtailment would be shared by each of the generators based on the ratio of rated or actual generator output to total required curtailment. Implementing this method would not require a change of regulation and would grant fair access for multiple generators. 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 generation is connected the level each generator needs to curtail will increase – this can be solved by setting a cap on the level of generation which can be connected behind a particular constraint.

Shedding Rota

This method operates in a similar manner to the LIFO arrangement, with the difference being that the priority order is changed using a rota system. This rota could be changed on a daily, weekly or monthly basis depending on the network operator's discretion. All generators will be treated equally. Careful consideration should be given to the frequency of the rota. Should length of time between position changes be too long then generators could be unfairly curtailed due to seasonal variations in demand e.g. more curtailment expected in summer when compared with winter.

Technical Best

A Technical Best arrangement aims to curtail the generators in order of contribution to the prevailing constraint or based on which generator(s) response characteristics are deemed best for meeting the constraint. This may vary for different types of constraints and network configurations. This approach would ensure the most efficient operation of the network however it may unfairly discriminate against certain types of generators based on their location, control room preference and generator size.

Greatest Carbon Benefit

This method aims to minimise the carbon emissions associated with actively managed generation by curtailing the largest carbon emitting generators first. Based on a carbon metric such as CO_2/MWh per generator the network operator could prioritise generation. This method could be implemented in conjunction with another method of access arrangement with the banding of generator carbon emissions being linked to ROC banding. The greatest difficulty faced will be the calculation of the real carbon footprint of each generation in a clear, open and fair manner.

Most Convenient

This method allows system operators to curtail the generator they know to be the most convenient for responding to network constraints. There may be unfair discrimination against certain types of generators based on location, control room preference and size of generator. The assessment may also be influenced by system operator preference.

Generator Size

This method curtails the largest generator that is contributing to a constraint first. The total amount of curtailment required to alleviate a constraint is allocated in order of size. Generator size may refer to the installed rated capacity of the generator unit or the power output at any given time when constraints arise. This method has the advantage of easing network congestion quickly by removing the largest generator first. Problems arise when a number of generators are of similar size, and determining whether the size considered is the size available or the installed capacity.

3.2.2.2 Market Principles of Access

A Market PoA uses a curtailment market to determine the curtailment order of non-firm generation. The system operator would run the market, and generators may submit bids to indicate their willingness to curtail. This type of arrangement places more control in the hands of the generator over the issue of enforced curtailment. There would be compensation paid for curtailment, and a charge for use of the curtailment market. This model is based on the current transmission system balancing market. To apply a market arrangement at distribution level would require significant changes in distribution network codes and the creation of a new market system.

Curtailment Market

A curtailment market might take the form of generators submitting bids on an annual, quarterly or monthly basis in which they indicate their willingness to curtail. In a perfect market, this bid would be equal to the price the non-firm generator would have received had they been allowed to generate during the constraint period. The system operator will always aim to clear the constraint with minimum cost to the system i.e. the lowest bids will be curtailed first. Compensation might be paid-as-bid, reflect the curtailment market clearing price, or be a fixed price e.g. a percentage of the price of wholesale electricity during that particular period. This option gives control to generators to submit bids which reflect their desire to remain connected and could encourage participation from existing firmly connected generation. However a new market system would need to be established and it may require large changes to the distribution and grid codes.

3.2.3 Assessment of Principles of Access against Criteria

Table 3-1 gives an overview of the advantages and disadvantages discussed above. A point is given for each assessment criteria the PoA meets. A total is given in the far right column of the table and the highest scoring PoA selected for further analysis.

Table 3-1 Comparison of Principles of Access

	Comply with Grid Codes	Support Safe, secure and reliable power	Efficient network operation	Clear and transparent	Flexible for the future	Gain support of all stakeholders	Simple to implement	Be robust	Future bankability for investors	Total no. of criteria met
Last In First Off	1	1	0	1	1	1	1	1	1	**8**
Pro Rata	1	1	0	1	1	1	1	1	0	**7**
Shedding Rota	1	1	0	1	1	1	1	1	0	**7**
Technical Best	1	1	1	0	1	0	0	1	0	**5**
Greatest Carbon Benefit	1	1	0	0	1	0	0	0	0	**3**
Most convenient	1	1	1	0	1	0	1	1	0	**6**
Generator Size	1	1	1	0	1	0	1	1	0	**6**
Market	1	1	1	1	1	1	0	1	1	**8**

LIFO, Pro Rata and Rota arrangements are the highest scoring non-market arrangements. These three arrangements can be considered to be clear and transparent, to support network operation and ensure a safe, secure and reliable power system. In the case of Pro Rata it is necessary to define some additional rules in advance of connection to ensure that curtailment estimates are fair and generators can estimate return on investment. The remaining four non-market arrangements were not selected for further analysis due to their low scores against the assessment criteria. The Technical Best arrangement, whilst offering efficient network operation is not likely to gain support of all stakeholders as a result of it not being clear and transparent. The complexities of network operation may complicate this curtailment scenario and cause confusion. It would be difficult in this case to estimate the volume of curtailment experienced by any new generation connecting to the network. Similar arguments hold true for a ‘Greatest Carbon Benefit’ and ‘Most Convenient’ arrangement. In particular, it is very difficult to quantify the ‘carbon footprint’ of a generating plant. This could be based solely on fuel type however this could then be considered unfair discrimination between technologies.

A Market arrangement is the fourth arrangement to score highly against the assessment criteria. While it might be considered one of the most difficult to implement, a market arrangement would ensure efficient network operation, bankability and gain support of all stakeholders as compensation would be awarded for curtailment. Those who do not wish to be curtailed can submit bids which reflect this. The next section will provide more details on defining the design of a market PoA.

3.3 Design Review of an Electricity Market for PoA

Continuing on from PoA identified in the previous section, there is a need to expand on market design and define the potential types of market PoA that will be compared.

3.3.1 Characteristics of Electricity Markets

There are a number of characteristics used to define the type of market used. These include:

- the size of the market
- the number of stakeholders involved
- the degree of unbundling
- the degree of competition
- the style of interaction between buyers and sellers

In general, markets can be defined initially by the level of unbundling and competition which exists within them. The four types of market are listed below as an example [106]:

- Vertically integrated monopolies
    - There is no competition with a utility monopoly and the government oversees the market operation
- Unbundled monopolies
    - Competition exists at generator level, but not at retail level
- Unbundled market limited competition
    - Generation is separated from all other functions. There is competition at wholesale level between generation and no competition at retail level
- Unbundled market full competition

- Complete competition at wholesale generation and retail levels. This can include market based demand side integration

Currently the GB electricity system has an unbundled market with full competition and this is regulated by Ofgem.

For the design of a curtailment market, the level of curtailment must be matched by offers from generators (as opposed to the level of generation meeting the level of demand in the wholesale electricity market). The market should be unbundled and there will be competition between generators.

Similar to the criteria set out for assessing PoA, there are certain criteria which must be fulfilled for a successful market design. A number of authors have addressed the issue of electricity market design. Kuri et al [107] suggest that the design process should start by turning market objectives into specifications, which can then be used to determine the optimal market structure and rules to ensure these objectives are met. The market structure refers to the market participants and the commercial and legal contracts that bind them. The market rules define the relationships between market participants.

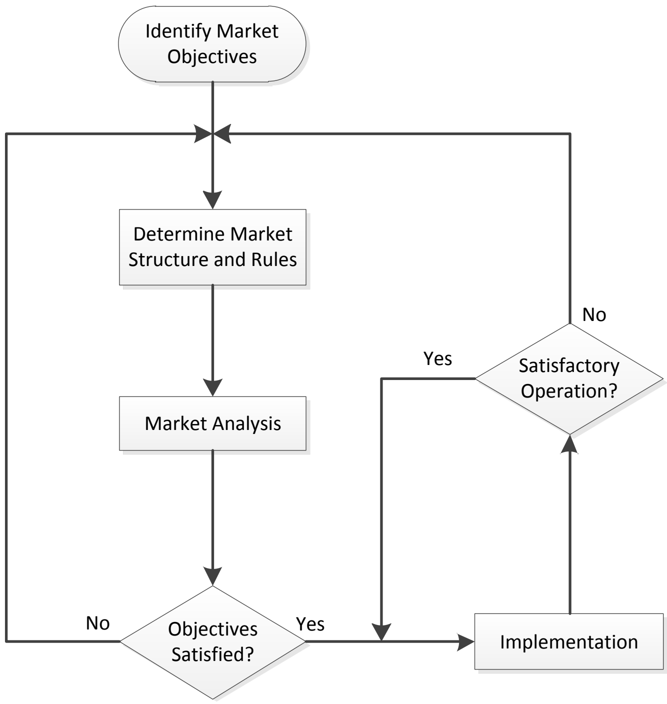

Figure 3-2 Market design process [107]

Four basic electricity market structures [108] are outlined below:

- Mandatory pool with System Marginal Price (SMP)
    - Generators and electricity suppliers submit bids into a pool, which the market operator can then match up supply and generation values. Bids from generators are accepted in merit order (starting at lowest cost and working up). The last generator bid accepted to meet demand levels is now the SMP and all generators will be paid this price for electricity generated, and all demand will be charged this rate for electricity.
- Mandatory pool with Pay-as-Bid (PAB)
    - Similar to the first market structure, this method operates in a similar manner with all bids and offers for electricity submitted to the pool. The difference is in the price of electricity, generators will receive the bid price they submitted in return for electricity and suppliers will pay an average of all accepted generator bid prices.
- Contracts with dispatch priority and system balancing
    - This is the model currently used by the GB electricity market. This model encourages generation to enter into contracts in advance of the trading period by using bilateral contracts. Generators and suppliers also have the option to trade in the 'Balancing Mechanism' where the market operator does final alterations to ensure generation matches demand levels (see Section 2.3.1)
- Simple centralised market
    - An independent operator manages a centralized market i.e. all generators and suppliers submit bids to a centralised pool and the operator is responsible for verifying input costs and contract terms.

The problems with electricity market design are discussed by Cramton in [109]. Cramton states that "good market design identifies the critical issues, and then addresses them as simply as possible, but not more simply". This points to a number of problems with electricity market design, whereby in trying to simplify the design, the market has performed poorly i.e. a market which results in the increase of system price, rather than bring costs close to generator marginal costs.

The paper goes on to outline critical considerations for market design. Including:

- Good knowledge of the underlying market.
- Understanding the politics, preferences and constraints of key market stakeholders and participants.

- Avoid over simplification of market design, to the end that it causes negative market behaviours. All complexities in the market must be addressed.
- Demand response can have a significant impact on reducing the impact of market power. Market design focuses on the generation side of the pool, however by switching focus to demand side; greater market efficiencies could be gained.
- Be aware that the method of pricing has a significant effect on behaviour. A system marginal price (SMP) market is better suited to smaller participants, while a pay-as-bid (PAB) market suits participants who are better equipped to calculate the market clearing price, and can therefore bid accordingly.
- Careful simulation and assessment of the market design features should be carried out before the new design is implemented.

Cramton [109] comments on a number of simplification examples and suggests that forward markets reduce game playing and reduces risk to participants – real time markets can be more volatile and vulnerable to manipulation. In a similar vein, locational pricing is essential for systems with transmission constraints in order to send the right signals to developers about where to build future generating plants. This is done in the UK by varying the Transmission use of system and connection charges, and in PJM by having 'Locational Marginal Pricing' i.e. the cost of generating electricity is higher in constrained regions.

These suggestions concur with an academic report produced for Project TransmiT, where Bell et al [104] make a number of recommendations for any proposed new changes to transmission charging arrangements.

Zhou et al [110] have analysed market designs using agent based modelling and genetic learning algorithms. They have found that the removal of a price cap, and the introduction of costs to reflect consumers consumption of electricity i.e. limit the amount customers have to spend on electricity in any given trading period. This results in lower clearing prices and lower instances of capacity withholding behaviour from generators when compared with another PAB market with a cap on maximum bid, and no link to consumer costs.

3.3.1.1 Trading Methods – Pool vs. Bilateral and Spot Markets

In a centralised market, all energy is traded via the pool, as demonstrated by the schematic in Figure 3-3. This is the most common type of market and is used in the USA and Australia. All suppliers must purchase their entire demand from the pool and there is a unidirectional exchange of energy from producers to pool and then to suppliers. A final production schedule is determined by the market/pool operator, and they will also decide on the price to be paid for energy using a central algorithm. The central pool can be divided into a Gross Pool and a Net Pool.

The Gross Pool can be applied to wholesale markets. The entire output of each generating unit is determined by the market operator, the generator has no influence on the production schedule.

The Net Pool allows the producer to determine an initial production schedule, which then provides the basis for offering any changes to this base schedule into the centralized market. This method is a hybrid between a pool and bilateral contracts market.

The majority of pool systems are based on unit-based offers i.e. producers have to submit separate offers for each individual generator. Market clearance takes account of technical characteristics of the generators and network behaviour.

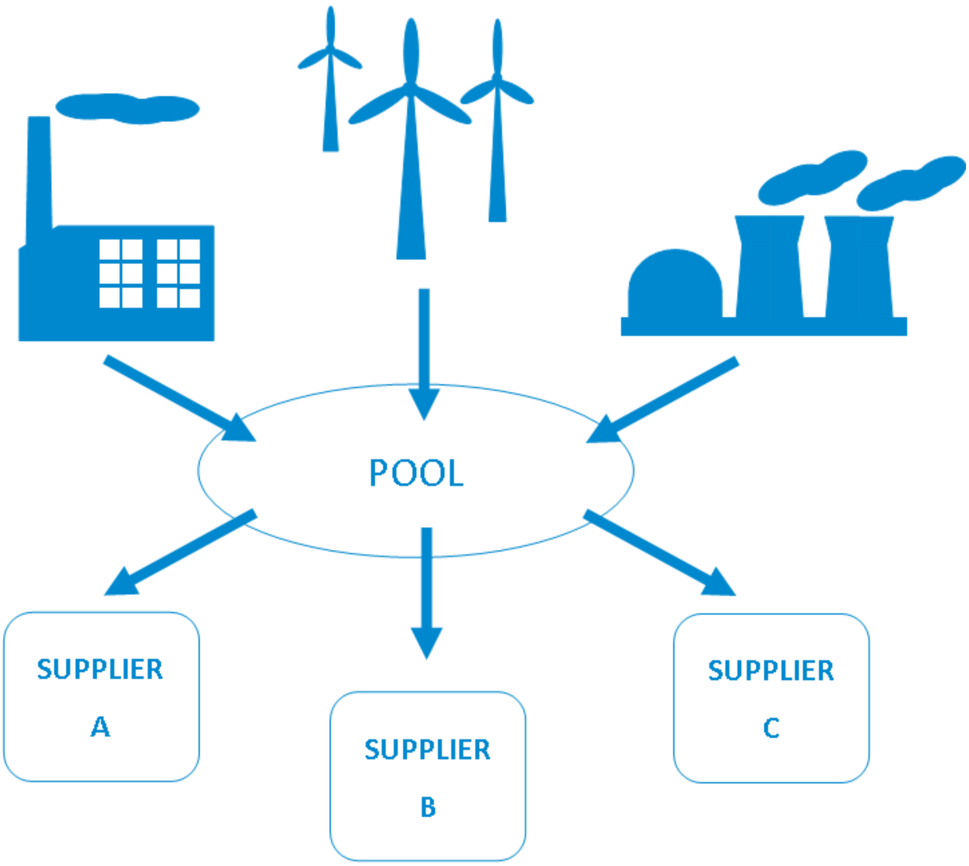

Figure 3-3 Diagram of pool trading method

In a bilateral (or decentralised) market, all market participants are free to engage in any type of contractual obligations for the delivery of energy. This is demonstrated by the schematic in Figure 3-4. Generators are self-scheduling and there is a bidirectional exchange between any two market participants. Power Exchanges facilitate two-way bidding – the market is cleared on the combined supply and demand curves from generation and demand. In this market, energy is considered a tradable commodity and all technical constraints must be managed by the generator. Due to these technical constraints, this structure requires a well-developed and strong electric grid. Examples of countries using bilateral markets are Germany, GB and the Netherlands.

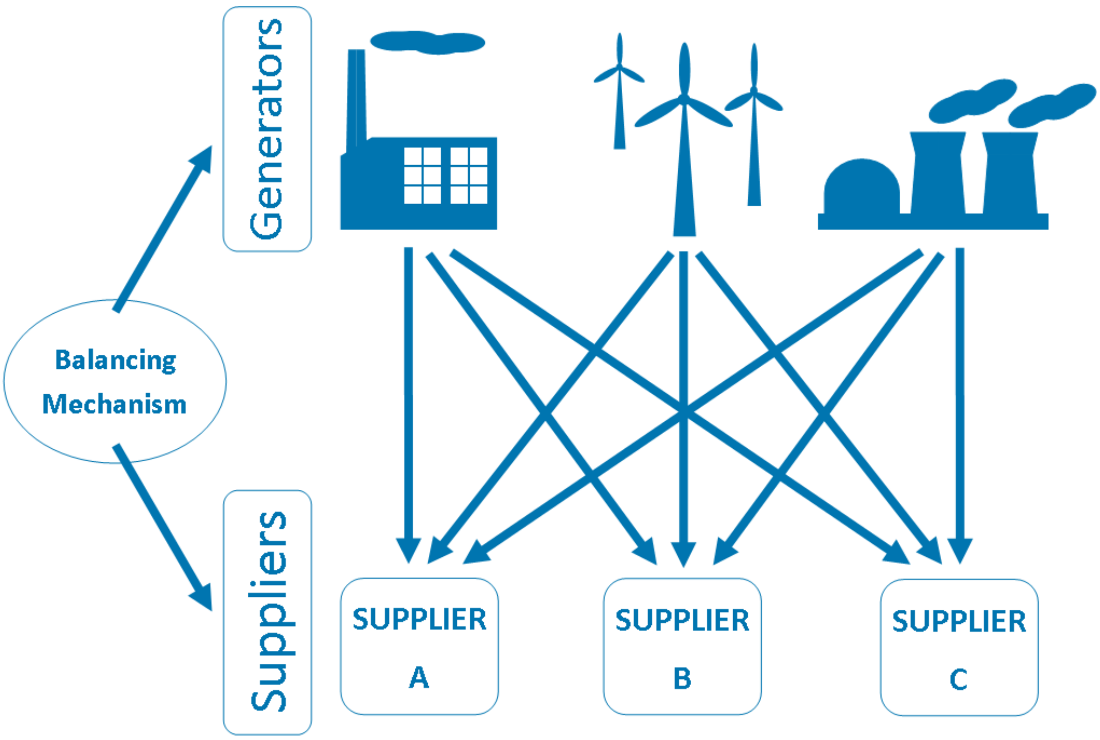

Figure 3-4 Diagram of bilateral trading market

3.3.2 Types of Auction

There a number of Auction formats that can be adopted when trading in power systems. These include

- One-sided auction i.e. trading of generation only, no demand side response.
  - Sealed-bid
  - Descending clock (dynamic)
  - Hybrid
  - Combinatorial
- Two-sided i.e. both generation and demand is traded.

Table 3-2 gives an overview, advantages and disadvantages of the auction categories and the particular auction designs.

Table 3-2 Comparison of Auction Designs [111]

Auction Style	Overview	Auction Design	Further Details	Advantages	Disadvantages
Sealed-Bid	All bidders submit a single bid at the same time, without knowing other bidder information	First Price Sealed Bid (FPSB)	Typically used when a single contracted item has a well-known cost, or can be calculated by bidder. Auctioneer accepts the lowest bid price. This option is typically used for construction projects.	Simple design that has been widely used with low participation costs. As bid information is not shared, it prevents collusion between bidders to raise clearing price.	Failure to accurately predict price of contracted item may lead to a loss in profit for the bidder. All uncertainty is contained in a single bid price.
		Pay-As-Bid or Discriminatory	Used when there are multiple units to be allocated to bidders. Bidders submit a supply function i.e. prices and quantities. The auctioneer collects all bid information and creates a supply curve. Winning bidders are those who have prices below the clearing price. Winners receive the same price which they have bid for units. This type of auction is typically used for PPAs and mid to long-term energy contracts.	Bidders are certain of the payment they will receive should they win bid.	Uncertainty contained in single bid – could under estimate cost of contract.

		Uniform Price Sealed-Bid	Similar to Pay-As-Bid mentioned above, except accepted bidders will receive the same payment – the market clearing price. Typically used for spot energy prices, and capacity contracts.	Tends to attract participation of smaller bidders which helps improve competition, and is felt to be a 'fairer' way of determining price.	If bidders have a large variation in cost structures, a uniform price may be deemed 'unfair'
Dynamic Auction	Price of contracts determined through multiple bidding rounds. Main purpose is to allow market to discover true cost of contract/product.	Descending Clock	The auctioneer starts the highest price, and asks which bidders are willing to sell at this price. If the total quality is not met after the first bid, the auctioneer drops the price and repeats the process until offers match the quantity required. The winner receives clearing price. This type of auction is used in capacity and energy contracts.	Efficient in terms of price discovery – the bidder can adjust bids based on information from previous bidding rounds and the auctioneer can run multiple descending clock auctions at the same time for different products. It is more transparent than sealed bid auctions as the process for awarding winning bidders is open	This has a more complex design when compared with other auctions. If competition is weak, then revealing bidding information can have a negative effect on competition e.g. encourage collusion.
Hybrid	Ability to tailor market to suit specific needs – using best of both sealed bid and dynamic auctions.	Descending Clock stage followed by Pay-As-Bid	Uses a dynamic auction in the first phase to allow price discovery, followed by a Pay-As-Bid auction for those who are successful in Phase 1. This auction is used for mid to long-term energy contracts	Phase 1 allows bidders who can provide contracts at lowest costs through to Phase 2. Switching to Pay-As-Bid allows minimal collusion and allows further reduction of prices.	This design is complex, there is an increased number of processes for participants to be aware of.

		First Price Sealed Bid stage followed by an Iterative Descending Auction.	Phase 1 consists of a Sealed-Bid processes. Lowest bidders go through to Phase 2 where a descending auction is run. Level of information disclosed during Phase 2 depends on Auction design details. This design is used for products where the value is relatively well known and price discovery is not important.	Phase 2 allows further reduction of prices submitted in Phase 1.	This is a complex model, there is an increased number of processes for participants to be aware of.
Combinatorial	These auctions provide a framework for the sale of multiple items.		Items are 'packaged' together (either defined by auctioneer or bidders) and bidders submit prices to buy whole package. They can be dynamic auctions, sealed bids or a hybrid arrangement. Typically used for mid to long-term energy contracts	This method allows products to be grouped together for auction. If the bidder defines the package it can grant greater certainty for the bidder and reduces the problem of exposure.	This is the most complicated of all auction designs. There may be technical issues which may prevent bidders participating in auction. This decreases competition and possibly the efficiency of the auction. Determining the winner can be complex and not often transparent.
Two Sided Auctions	Both bids and 'asks' are submitted and matched by auctioneer i.e. participation of both supply and demand		Active participation of both supply and demand. This auction can be used to incorporate Demand Side Response into market.	This helps to control market power and can reduce clearing price.	As this is not the norm, it may take time to develop regulatory changes and overcome obstacles which prevent Demand participation in auctions.

3.3.3 Options for Curtailment Price

For the curtailment market proposed in this study, there are only certain auction designs that are applicable. For example, two-sided auctions are not appropriate as the curtailment volumes are non-negotiable. A combinatorial auction is not required as the market deals with relatively small volumes of energy trade, on a small scale market and therefore there is no requirement for packaging units together. As participants in the curtailment market are likely to consist of smaller generators, this would suggest a uniform system price payment per unit of curtailment would best suit the market. However, this could unfairly penalise the small proportion of larger developers who participate in the curtailment market.

In the previous sections, we discussed different market and auction designs. Within each structure there are limited options available for setting the contract price:

1. System Price
2. Pay-As-Bid
3. Fixed Price

In any market, all participants will aim to maximise profits. The main issue for wind generation is that they need to make enough profit in order to cover large upfront investment costs, as they have negligible fuel costs when compared with conventional generation plant. The topography of the distribution system will also have an influence over market behaviour i.e. the location of generators relative to constraints will have an impact on the level of bids, and the behaviour of generators. [112]

3.3.3.1 Option 1: System Marginal Price

A **System Marginal Price** (SMP) is the most common market architecture/structure used in electricity markets. The SMP is the price at which energy is both bought from generators and sold to consumers. A SMP market has a 'pool' through which electricity is traded. All generators receive the SMP for energy during the relevant trading periods. The SMP is determined by the SO and the price is based on start up and running costs of generators, in addition to the price it will cost the marginal generator to increase its output to meet system demand.

Examples of SMP markets include Northern Ireland and Republic of Ireland wholesale electricity market SEMO [113]. The reason SMP is widely adopted across many systems is due to its ability to allow generators to make a profit while bidding in at their true costs. However, generators can also play the market to their advantage and submit untrue costs in order to increase profits when the opportunity arises. This raises the system price, which increases the social cost of electricity because the price charged to customers, is the price paid to generators.

Analysis of SMP has been carried out by a number of authors [114], with the main focus of research looking into the forecasting of SMP using neural networks. Forecasting of SMP is important for generators to allow them to submit bids at the appropriate level for the next trading period.

Simoglou et al [115] discuss the impact of increasing renewables on the SMP. The authors use the Greek market clearing algorithm to calculate the SMP for 10 different scenarios in the Greek Electricity Market. Each of the ten scenarios, has a linearly incremental level of installed renewable energy capacity, and are calculated for four typical days of the year – Winter peak, spring off-peak, summer peak, and typical autumn. Results show that the increase in renewable generator capacity has a significant reduction in the SMP, which can be explained by the fact that renewable generators submit zero-bids (i.e. when compared with conventional generators, they have zero fuel costs). A reduction in SMP would reduce the price paid to all generation, therefore conventional generation would see profits decrease and may begin to increase bids in order to raise SMP back to a preferred level.

A number of papers deal with the issue of forecasting the system price in a uniform price market. While in a perfect market, it is assumed generators will always bid their own marginal costs, marginal price forecasting is used to raise or lower bids accordingly so that generators can ensure a small 'mark-up' on their own marginal costs.

The most common method for forecasting system marginal pricing is by the use of neural networks [116]–[119]. Neural Networks are used to solve artificial intelligence problems, and are suited to market scenarios as they simulate the behavioural characteristics of market participants.

Ding et al [117] have used a specific kind of Neural Network, known as CMAC – Cerebeller Model Articulation Controller. This method uses a look-up table method, and each of the input values is weighted. This method is often used when the imprecision of human reasoning i.e. vagueness, lack of information, is a key factor. The simulation results show that this method performs fast analysis, and stable outputs are produced.

Byounghee et al [118] use a system type neural network architecture to forecast system electricity price. In this method, a surface is determined from a given data set and is expanded along one axis. A transform is then applied to the reference surface to generate a forecast surface. Past power data and SMP are the key parameters used to forecast future SMP values. Other parameters are also included, such as special events days, population growth, season, time period (i.e. morning, noon, evening). Data from the Korean Power Exchange was used to perform forecast simulations. The results demonstrate that certain days have a larger variation of SMP when compared with others. Typically the variation on Saturday and Sunday is greater than during the week, most likely due to a change in energy use at the weekends. The results also depend on how close demand patterns in the reference year are to the forecast year. Overall the percentage errors for each hour of the year is never greater than 4.9%.

Saebi et al [119] have looked at the impact of demand bidding on the market clearing price. It has been suggested in the previous sections (See Table 3-2) that a double-sided auction i.e. the inclusion of demand bidding, would result in a more efficient market, and a lower marginal clearing price with the introduction of responsive demand. Based on the CIGRE 32-bus system, simulation results show that during peak hours, marginal clearing price and overall system costs are reduced with the inclusion of demand side bidding. From a purely demand side consideration, profit for consumers increases and peak load reduces during peak hours when price spikes typically occur. A number of linear inputs are put into the model, and a single prediction is produced as the output.

Application of SMP to a Curtailment Market

In terms of a curtailment market, the SMP would be referred to as the Curtailment Market Clearing Price (CMCP). The point at which the constraint is cleared sets the SMP and all generators who helped to clear the constraint would be paid this CMCP. The diagram in Figure 3-5 demonstrates this concept. The dashed red line on the graph indicates the volume of curtailment required, $MWCurt_i$.

Curtailment of non-firm wind farms could be allocated on a shared basis, or by priority order based on size of bid submitted. The creation of a curtailment pool in which the market operator could select the required level of curtailment to clear constraints may be better than bilateral trades.

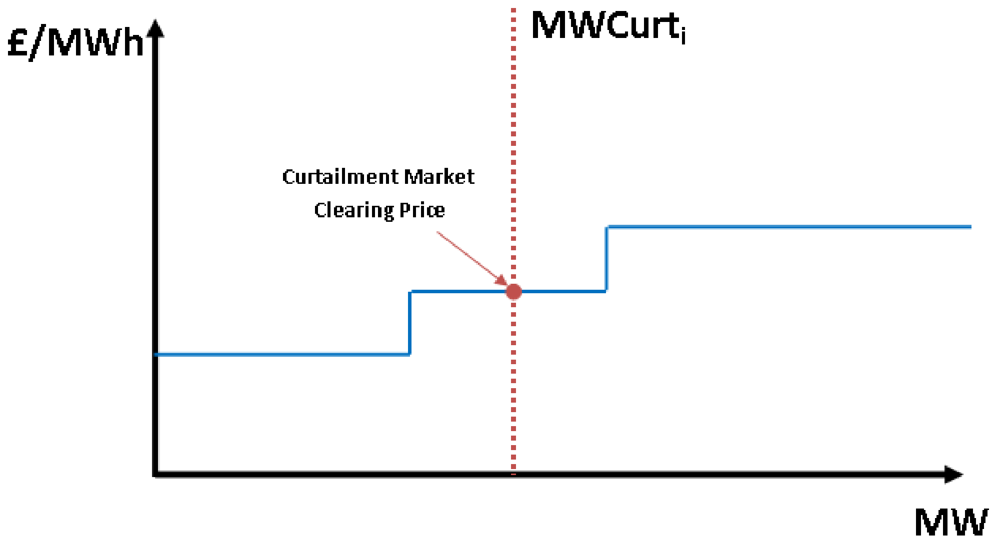

Figure 3-5 Curtailment market clearing price

3.3.3.2 Pay-as-Bid

Pay-As-Bid (PAB) is not widely adopted for electricity markets, as it often discourages generators from submitting bids that reflect the true marginal costs of production [120]. Generators will guess what the SMP is likely to be, and aim for maximum revenues. This would result in an unchanged SMP. A number of authors have looked at the impact of adopting a PAB market for the trading of electricity. In 2001, the GB electricity market moved to a PAB market (for the balancing element of the market, majority of electricity for the GB electricity market is still secured via long term contracts), in the hope of discouraging tactical bidding by participants and to reduce the market power held by large generating companies [121]. The price charged to customers is the average price paid to generators.

Analysis into PAB markets has been carried out by a number of authors who have shown that issues can arise for generators trying to estimate the system price due to lack of information of other bidding strategies.

Mozdawar [122] presents an objective function to find the optimal bidding strategy for generators in a PAB market. The author uses a Bertrand model to determine the objective function based on its suitability to a PAB market and to the case study of the Iranian power market. The Bertrand Model assumes generators submit bids at level of marginal costs of

Nash equilibrium[4] point and that all generators participate in the market based on the price offered. Assuming each bid reflects true costs of the generator, and then the desire is to have a bid price which is lower than marginal clearing price to ensure significant profits from the market.

Arguments for and against SMP and PAB are based on qualitative analysis, however [119] and [121] have carried out quantitative analysis on SMP and PAB impacts on market behaviour.

Careri et al [121] show the effects on bidding strategies adopted by generators under different market structures. A comparison of PAB and SMP is carried out using game theory and genetic algorithms. The results show that under SMP, generators who own multiple units withhold energy of larger units in order to raise the system price through the use of smaller, more expensive units. Generators in a PAB market suffered a drop in profits when compared with SMP market. Generators refrained from increasing bids to too high a level above marginal costs to avoid risk of not producing energy. Generation that provided a base load supply, had the highest bid price. From a consumer stand point, the PAB market resulted in a lower energy price, and less fluctuation in pricing.

In Part I of a two part study by Ren et al [123], the authors develop the 'best' generator offers for both PAB and SMP, and determines the bid which maximizes the generator profit. By calculating uncertainty ranges for system marginal costs, the paper determines that the best strategy for generators under marginal price is to offer true costs and generators in a PAB market should submit a bid which not only reflects true costs, but considers system uncertainties in order to obtain the maximum profit. In the second part of the study [124], the authors go on to identify relationships between system marginal costs for each market type in order to compare the two markets in terms of generation profits and consumer payments. System demand is assumed to be a random variable within a pre-defined range. The result of the numerical analysis shows that while the generators profit and customer payments are the same for a given demand value under both PAB and SMP, the uncertainty in the customer payments is greater under SMP when compared with PAB, as is the standard

[4] In game theory, the Nash equilibrium is a result of game theory where each player is informed of the other player's strategies and no player has anything to gain by changing their own strategy.

deviation of profit for an arbitrary generator under SMP when compared with PAB. These results assume a perfect market, and although this is not necessarily the behaviour experienced in a real system, the results do demonstrate an important concern in SMP markets.

Kahn et al [125] have suggested that switching from SMP to PAB has reduced the incentive to exercise market power. It suggests that changing a market system from SMP to PAB would cause substantial problems with the market, which highlights the importance of a transition plan for any market operator when making changes to long-standing market arrangements. By switching to PAB, the additional payments gained by generators who bid below uniform price will be lost. Bidding practices will change to generators trying to guess the system price and bidding at that level, instead of basing bids on their own marginal costs. The authors also suggest that PAB will reduce market efficiency and discourage competition and the paper agrees with other literature that PAB would be a disadvantage to smaller competitors due to their lack of ability to accurately forecast system price. The authors conclude that instead of switching to PAB, there are other ways to improve the SMP market such as:

- Interventions to prevent withholding of supply
- Introduction of long term energy contracts and power exchanges
- Price response of demand customers.

Stacke et al [126] analyse the behaviours of SMP and PAB strategies in a combined market structure where long term forward physical bilateral contracts are the main method of contracting electricity. Short term trading such as pools and ancillary service markets also exist. This market model is similar to the GB electricity market. The aim of the model is to demonstrate the ability to exploit the centralised market. Stacke uses an integration process to model a PAB incremental model. Analysis was carried out using an IEEE 5-bus system, with generation and load at each bus participating in the market. The results show that the PAB model results in a lower total cost of operation when compared with SMP. When a larger volume of energy is contracted through use of bilateral contract, the SMP method shows a higher level of volatility in nodal price, while PAB method results in a more stable average price. As the analysis was performed on a relatively small system, there would be little effects of location or congestion on the network, which could lead to further changes in market behaviour.

Application of PAB to a Curtailment Market

In a curtailment market, the curtailment price would be equal to the bid submitted by the generator. The market operator is still trying to clear constraints at the lowest system cost and will therefore select the lowest bid price first to meet curtailment levels, and then choose the second lowest bid etc.

It is assumed that the level at which generators submit bids will initially be based on the expected value of lost revenue cause by curtailment. This level is likely to change over time, and could result in collusion by multiple generators. As there is no flexibility in the volume of curtailment needed (similar to an inflexible demand) there could be potential for market inefficiencies.

3.3.3.3 Fixed Price

The **Fixed Price** scenario differs to the first two markets, as it is not a true market. There are no bids or offers submitted. Instead, the Market Operator compensates curtailed generators with a fixed price. This fixed price can be determined by the market wholesale price of electricity for the time period in question e.g. the Spanish system operator compensates curtailed generators at a price which is a percentage of the wholesale electricity price [54]. This ensures generators still receive a suitable level of costs to cover any overheads.

While this model might be considered appropriate for compensation payments for curtailment of wind farms, a fixed price model is not adopted for the buying and selling of electricity as it is not conducive to an effective market structure.

3.3.4 Market PoA Conclusions

Based on the discussions in this section, it is felt that the curtailment market should take on a pool form. All generators wishing to bid into the curtailment market must submit a bid in advance of the gate closure which indicates their willingness to curtail. All non-firm generators must enter a bid in to the market, otherwise the market will assume a zero cost and no compensation will be granted. Firm generators can choose to bid whether to participate in the market.

Generators will only know their own bids in to the market i.e. the bids will be sealed, and will be informed of the system price when necessary. Bids placed account for one 24 hour period. Due to the variability of wind, it is felt that bids for a longer time period would be inappropriate as conditions are likely to have changed. Bids for a shorter time period would add complexity to the system for both generators and system operators.

The market operator will organise the bids and will curtail generation in order from least to most cost until the network constraint has been relieved.

This thesis will compare the costs of three different compensation methods

- Pay-as-bid
- System Price – to be known as Curtailment Market Clearing Price
- Fixed Price

The bids will be based on the profits generators expect to make when operating uncurtailed. The calculation of the bids and the methodology is explained in more detail in Chapter Four.

3.4 Power System Evaluation Techniques

In order to compare the impact of different PoA on the output of wind generators in ANM schemes, we must first determine the best method of modelling these arrangements.

System operators use power-flow analysis software to monitor the network and ensure that:

- generation supplies the load
- voltage magnitudes are within limits
- real and reactive power are within limits
- transmission lines are not overloaded

This monitoring becomes more important with the increase of embedded generation in distribution networks, as the network power flow is no longer passive and needs to be actively managed.

The power-flow problem involves the computation of voltage magnitude and phase angle at each bus in a power system under balanced three-phase steady state conditions. Real and reactive power flows (in equipment such as transmission lines, and transformers) and equipment losses can then be calculated.

The basic load flow problem is given by the following nonlinear equations:

$$Y = g(X) \qquad \text{(eq. 3.1)}$$

$$Z = h(X) \qquad \text{(eq. 3.2)}$$

Where:

X is the vector of unknown state variables

Y is the vector of predefined input variables

Z is the vector of unknown output variables

g, h are load flow functions

The power system first needs to be translated into a mathematical model for analysis. There are four bus variables:

$$V, \delta, P, Q$$

Where *V* is the bus voltage magnitude, δ is the bus voltage phase angle, P is the magnitude of active power injection and Q is the magnitude of the reactive power injection. At least two of these variables are known at each bus depending on the bus type.

There are three bus types: Swing Bus, Load Bus and Voltage Bus. The Swing Bus (or slack bus) is used as a reference bus for the network in question. The input data used at this bus is V = 1.0 and $\delta = 0^{\circ}$ and this can be used to calculate P and Q using power flow analysis.

At a Load (PQ) Bus, P and Q are known and the power flow computes V and δ. Most buses in the network under analysis will be load buses.

At a Voltage Controlled (PV) bus, P and V are known, and the power flow calculates Q and δ. Examples of PV buses are those to which generators, switched shunt capacitors or static VAR systems are connected.

3.4.1 Classical Power Flow Methods

The following methods are classic solvers for power flow methods. These basic solvers form the building blocks for power flow simulations of larger power systems.

Gaussian Elimination is an algorithm for solving linear algebraic equations. It allows the user to obtain a direct solution through triangulation of a matrix followed by back substitution.

Consider the following set of linear algebraic equations in matrix form

$$\begin{bmatrix} A_{11} & A_{12} & \dots & A_{1N} \\ A_{21} & A_{22} & \dots & A_{2N} \\ \vdots & \vdots & \ddots & \vdots \\ A_{N1} & A_{N2} & \dots & A_{NN} \end{bmatrix} \begin{bmatrix} x_1 \\ x_2 \\ \vdots \\ x_N \end{bmatrix} = \begin{bmatrix} y_1 \\ y_2 \\ \vdots \\ y_N \end{bmatrix} \qquad \text{(eq. 3.3)}$$

Or

$$\mathbf{Ax} = \mathbf{y} \qquad \text{(eq. 3.4)}$$

Where **x** and **y** are *N* vectors and **A** is an *NxN* square matrix. Given **A** and **y** it is now possible to solve for **x**. This can be achieved easily if it is assumed the determinate of **A** is nonzero, and if **A** is made into an upper triangular matrix with nonzero diagonal elements by performing Gauss elimination. Back substitution can then be carried out to solve for **x**.

This method requires large volumes of computational capacity (based on the size and contents of the matrix) and is therefore not suitable for solving large power systems.

Jacobi and Gauss-Seidel are iterative solutions to linear algebraic equations.

The Jacobi method can be written in matrix format:

$$x(i+1) = Mx(i) + D^{-1}y \qquad \text{(eq. 3.5)}$$

Where

$$M = D^{-1}(D - A) \qquad \text{(eq. 3.6)}$$

And

$$D = \begin{bmatrix} A_{11} & \cdots & 0 \\ \vdots & \ddots & \vdots \\ 0 & \cdots & A_{nn} \end{bmatrix} \qquad \text{(eq. 3.7)}$$

For the Jacobi solution, **D** consists of the diagonal elements of the **A** matrix.

The convergence rate is faster with Gauss-Seidel for some matrices, but faster with Jacobi with others. This depends on the contents of the matrix. In some cases, both methods may diverge and a solution cannot be found. For sparse matrices (with few nonzero terms), special techniques can be employed to reduce computer storage and calculation time.

Newton-Raphson is an iterative solution to nonlinear algebraic equations. For nonlinear equations, the matrix D must be specified, and the method used is based on the Taylor series expansion of f(x) about operating point x_o.

$$\mathrm{y} = \mathbf{f}(x_0) + \left.\frac{d\mathbf{f}}{d\mathbf{x}}\right|_{x=x_0} (\mathbf{x} - \mathbf{x}_0) \ldots \qquad \text{(eq. 3.8)}$$

We can neglect the higher order terms and use the Newton-Raphson method to replace x_0 by the old value x (*i*) and x by the new value x(*i*+1):

$$\mathrm{x}(i+1) = \mathbf{x}(i) + \mathbf{J}^{-1}(i)\{\mathbf{y} - \mathbf{f}[\mathbf{x}(i)]\} \qquad \text{(eq. 3.9)}$$

Where:

$$\mathrm{J}(i) = \frac{\mathrm{df}}{d\mathrm{x}}\bigg|_{x=x(i)} = \begin{bmatrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \cdots & \frac{\partial f_1}{\partial x_N} \\ \frac{\partial f_2}{\partial x_1} & \frac{\partial f_2}{\partial x_2} & \cdots & \frac{\partial f_2}{\partial x_N} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\partial f_N}{\partial x_1} & \frac{\partial f_N}{\partial x_2} & \cdots & \frac{\partial f_N}{\partial x_N} \end{bmatrix}_{\mathrm{x}=\mathrm{x}(\boldsymbol{i})} \qquad \text{(eq. 3.10)}$$

This is the Jacobian matrix. The Jacobian Matrix orders variables so that bus voltage angles are grouped together before bus voltage magnitudes and similarly active power mismatches are grouped together first before reactive power ones.

This method is similar to extended Gauss-Seidel methods, matrix **D** is replaced by **J** (*i*). Most Newton-Raphson power flow problems converge in fewer than 10 iterations.

A Robust Newton's Method can be used in cases where the original Newton's method may cycle around the final solution without converging i.e. an ill-conditioned case. This method uses an optimal multiplier to improve the convergence properties of the iterative process.

A method to reduce the computation time further is to use Dishonest Newton's Method**.** This method reduces the time taken to factorize the Jacobian Matrix required for the solution, or eliminates it completely. The Generalized Minimal Residual (GMRES) Method is one method of doing this. [127]

A comparison of the above methods was carried out by Milano, and has shown that overall Newton's method is the best when dealing with well-conditioned power flow systems. In general, the smaller the number of manipulations carried out on the Jacobian arrays, the faster the computation time. The results of the comparison are shown in Table 3-3.

Table 3-3 Comparison of power flow analysis methods from Milano [127]

	Newton		**Jacobi**		**Gauss-Seidel**		**GMRES**		**Dishonest**	
No Of Buses	No. Of Iter.	Time (s)	No. Of Iter.	Time (s)	No. Of Iter.	Time (s)	No. Of Iter.	Time (s)	No. Of Iter.	Time (s)
14	4	0.0050	76	0.0217	56	0.0288	4	0.4339	7	0.0040
118	5	0.0287	580	0.505	388	2.738	7	53.53	15	0.0183
1228	5	0.210	454	5.120	224	0.0288	4	0.4339	7	0.0040
11856	4	3.15	340	399.0	173	2.738	7	53.53	15	0.0183

DC Power Flow is used to simplify the power flow problem by turning the problem into a linear one and therefore, ensuring a solution is reached. The key points to note about DC Power Flow are that all voltage magnitudes are assumed constant and equal to 1p.u. and reactive powers are neglected. The focus of this method is on calculating the power injections and bus voltage angles. This approach can result in some inaccuracies in the solution – which can lead to problems in system operation and increased balancing costs.

Load Flow techniques can be split into deterministic (DLF) and probabilistic (PLF) methods, but both techniques expand on the basic building blocks of the Newton-Raphson method. In DLF, the Jacobian matrix is computed for each iteration until the errors are reduced. In PLF, the Jacobian matrix is only calculated once for each load flow solution – errors caused by linearization of load flow equations should be treated with care.

DLF methods are used to analyse the power system at any single moment in time based on specific values of power injections and load demands at selected buses. Congestion management problems are better suited to PLF methods. Using PLF we can incorporate the uncertainties which lead to congestion on the network such as generator and network outages, and variation in demand.

The main objective of a model considering access arrangements is to use a power flow model which will incorporate true network conditions. This will ensure that even when constraints occur and curtailment is applied, the network model will ensure continued safe network operation.

3.4.2 Optimal Power Flow

Economic Dispatch is a computational model used to calculate the best way to distribute generation in a system to meet load requirements while minimising total operating costs. Lagrange multipliers provide a strategy for finding the maxima and minima of a function subject to constraints. To minimize the total cost, all units must have the same incremental operating cost, λ.

Inequality constraints can be incorporated into economic dispatch problems. For example, maximum output from generators: when limits are reached, these units are held at that limit and the remaining units operate at equal incremental operating cost λ. The incremental operating cost of the area is equal to the common λ for the units that are not at their limits.

As power systems have expanded, the need to consider the limit of load flows on transmission lines grew and economic dispatch was no longer suitable. A new method, known as OPF was developed.

3.4.2.1 Optimal Power Flows (OPF) Solvers

OPF algorithms are used to find a steady-state operating point which minimizes costs and losses while ensuring suitable system performance.

The constrained nonlinear programming problem is given as follows:

Minimize z

$$\varphi(z) \qquad \text{(eq. 3.11)}$$

Subject to

$$g(z) = 0 \qquad \text{(eq. 3.12a)}$$

$$h(z) \leq 0 \qquad \text{(eq. 3.12b)}$$

Where $\varphi(z)$is the objective function, g (z) are the equality constraints and h (z) are the inequality constraints.

A typical OPF-based problem is represented by the following [127]:

Minimize z

$$\varphi = -\left(\sum_{h\epsilon D} C_L(P_L) - \sum_{h\epsilon S} C_G(P_G)\right) \qquad \text{(eq. 3.13)}$$

Subject to

$$g(\theta, v, q_G, p_G, p_L) = 0 \qquad \text{Power flow equations} \qquad \text{(eq. 3.14)}$$

$$p_G^{min} \leq p_G \leq p_G^{max} \qquad \text{Generator p limits} \qquad \text{(eq. 3.15)}$$

$$q_G^{min} \leq q_G \leq q_G^{max} \qquad \text{Generator q limits} \qquad \text{(eq. 3.16)}$$

$$p_L^{min} \leq p_L \leq p_L^{max} \qquad \text{Load p limits} \qquad \text{(eq. 3.17)}$$

$$\left|\emptyset_{ij}(\theta, v)\right| \leq \emptyset_{ij}^{max} \qquad \text{Flow limits} \qquad \text{(eq. 3.18)}$$

$$\left|\emptyset_{ji}(\theta, v)\right| \leq \emptyset_{iji}^{max} \qquad \text{(eq. 3.19)}$$

$$v^{min} \leq v \leq v^{max} \qquad \text{Voltage Limits} \qquad \text{(eq. 3.20)}$$

Where $z = (\theta, v, q_G, p_G, p_L)$, c_G and c_L are vectors of functions of the generator and load powers; q_G refers to the generator reactive powers, v and θ refer to the bus phasor voltages, p_G and p_L refer to the bounded generator and load limits and φ_{ij} and φ_{ji} represent the active powers flowing through the lines in both directions.

An OPF problem can be solved using a number of established techniques [128]:

- Linear Programming (LP) Method
- Nonlinear Programming (NLP) Method
- Quadratic Programming (QP) Method
- Interior Point (IP) Method
- Artificial Intelligence (AI) Method

The first four methods are mathematic algorithms which incorporate economic factors (e.g. via use of Lagrangian multipliers) however there can be problems with poor convergence, and they are sometimes limited to finding a single optimal solution in a long run of simulations.

AI methods are able to handle various constraints, multi-objective optimal problems and converge quickly. It also has the advantage of allowing the problem to evolve without being tied to initial conditions. However AI methods do not consider economic information.

The ***Linear Programming (LP)*** method iterates between solving the power flow, and solving an LP to economically dispatch the generation. If system elements do not reach their limits, then the results will be identical to economic dispatch models i.e. the marginal cost of energy at each bus will be identical to the system incremental cost, λ. If any of the system elements reach their limits and the system becomes constrained, each bus price will now differ due to constraint costs. These differences are more commonly referred to as Local Marginal Prices (LMPs).

LMP determines the optimal generation unit dispatch while taking into consideration local energy and transmission congestion prices. A market based entirely on LMP would be a spot-based market and would not apply to any long term bilateral contracts agreed in advance of gate closure.

The **Nonlinear Programming (NLP)** method uses optimality problems with nonlinear objects and/or constraint functions. There are two kinds of NLP – constraint NLP, and unconstrained NLP. Lagrangian or Penalty function solvers can be used.

The ***Generalized Reduced Gradient (GRG)*** method is used for constrained nonlinear problems and is similar to the approach used in the simplex[5] method in linear programming. The variables of GRG method, z are divided into two subsets – the first consisting of dependent variables such as bus voltages, and the second consisting of independent variables such as generator active powers.

The ***Quadratic Programming*** method applies to a quadratic objective function and the constraints applied must be linear.

The ***Interior Point (IP)*** method is considered one of the best methods for solving power flow problems with constraints. They are particularly effective in large network scenarios. The method consists of a self-concordant barrier function which is used to encode the convex set[6]. IP uses a special class of barriers that can be used to encode any convex set. They number of iterations of the algorithm is bounded by a polynomial in the dimensions and accuracy of the solution. Karush-Kuhn-Tucker (KKT) conditions are used to accommodate non-linear problems such as OPF of an electricity network with constraints (flows, voltage, costs etc.). KKT allow inequality constraints by generalizing the method of Lagrange Multipliers (which only allow equality constraints).

Artificial Intelligence (AI) methods 'intelligently' search through a number of options to find the optimal solution. They typically involve the use of heuristic methods, or rules of thumb, which help speed up the process. AI methods include Evolutionary Algorithms (EA) which uses mechanisms inspired by natural biological evolution and particle swarm optimization (PSO) method which optimizes a problem by iteratively trying to improve a candidate solution (known as particles) by moving these particles around a search space. These

[5] In the Simplex Method, systems of linear inequalities are used to define a polytope as a feasible region. The simplex algorithm begins at a starting vertex and moves along the edges of the polytope until it reaches the vertex of the optimal solutions.

[6] A convex set exists if every pair of points inside an object, and every pair of points on a straight line segments that joins those points is within the object e.g. a solid cube is convex but anything which is hollow or has a dent in it (like a crescent shape) is not. A function is convex if its epigraph about the graph is a convex set.

particles are updated as better positions are found by other particles – and the particles (grouped together in a swarm) will move towards the best solution.

3.4.2.2 Application of OPF methods to Congestion Management of Power Systems

There are a number of power system evaluation techniques that can be used to analyse system behaviour during congestion management events.

A novel application of OPF for automatic power flow management is proposed by Dolan et al in [127] and [128]. The OPF method is used 'online' i.e. operating in real time in response to load and generation profiles. The outputs from the OPF analysis are control signals which are sent to generators in order to reduce loading on constrained lines. Power World is used to apply the OPF algorithm with additional programming code used to manage constraint information. The OPF method used is a Linear Programming method. A real-time simulator and substation computer are used to simulate real-time network operation. The LIFO principle is applied to all distributed generation on the network case studies, with the exception of an 'N-1' contingency event (i.e. the loss of a line) in which case the algorithm curtails the most relevant generation to the N-1 constraint. This allows greater energy yields across the DG units when compared with conventional methods such as inter-tripping all non-firm DG units. By looking at a number of curtailment scenarios on two different network architectures, the results have shown that the closed loop simulation has the potential to provide network operators with a real-time solution to constraints.

Boehme [131] proposes a method of determining distribution network limits for non-firm connection of renewable generation by using Time Series OPF. The method inputs hourly data for wind, wave and tidal data to calculate the output from a number of renewable generators on the Orkney distribution network. An OPF is run using the Interior Point method in order to determine if curtailment is needed anywhere on the system due to thermal overloads. This is a fully automated process using PSS/E and additional scripts in IPLAN programming language. The advantages of using the time-series method are that it provides an appraisal tool for the planning-stages when considering the development of a new renewable generator. It also provides an estimate of the curtailment volume the generator can expect to be subjected to under a non-firm contract, and therefore the economic loss which is to be experienced.

A probabilistic method for ultra-short term transmission congestion forecasting is developed by Guoqiang [132], and the proposed method is Boundary Load Flow (BLF) to find the lower and upper bounds for the probabilities. Monte Carlo Simulation (MCS) can then be used to obtain the probability distribution of power flows through transmission sections. BLF is used to find intervals of values for state and output variables, given intervals of input variables from probability distributions. These results can be used to determine multiple points of linearization for the load flow equations in order to improve the accuracy of BLF solutions [133]. The model is applied to an IEEE 39-bus system which is divided into four areas with three transmission boundaries. The results of the model show that it successfully predicts times of the day when congestion will occur at certain transmission boundaries and this information can be used by system operators to help reduce congestion caused by wind generators in particular.

Wang [134] proposes a new framework which allows improved real-time congestion management. The key feature of this method is the ability to change bilateral contracts when the balancing mechanism cannot sufficiently ease congestion. There are two sub-problems: solving for reactive power, and for real power. A Newton Raphson power flow and a prime dual interior point linear programming method is used. A linear bidding price curve is used to form the objective function which eliminates the need to linearize the problem. The nodal prices are obtained as by-products of the Primal-dual LP based OPF. KKT conditions are applied to the problem and predictor-corrector technique is used to reduce the computational time required to solve large power systems. The method is compared with a Revised Simplex Linear Programming method and has shown a significant reduction in the number of iterations and CPU time required to solve larger power systems.

The same authors propose a method of scheduling generation to eliminate congestion management in multi-regional system through the use of Lagrangian relaxation[7] [135]. This method allows individual transmission areas to maintain safe system operation with limited information from neighbouring regions. The approach will simplify an OPF problem by applying Lagrangian relaxation. Then, the multi-regional congestion management can be applied to the system. The independence of each region is maintained with the simple

[7] Lagrangian relaxation involves approximating a difficult problem of constraint optimization by using a simpler problem. The solution is an approximate solution, but will provide useful information.

exchange of Lagrangian multipliers. It is assumed that a schedule has already been agreed on the day-ahead market and each node has set the buy and sell prices. From this point, the model can be simulated to determine the optimal way to run the system while minimising deviations from the agreed schedule (and hence minimizing the cost). The model was applied to an IEEE RTS-96 bus system with 3 interconnected regions. All regional sub-problems could be solved in parallel with the inclusion of a slack bus in each region. The iteration process was likened to the haggling between buyers and sellers over prices, and when convergence is reach the optimal interchanges and prices can be obtained.

This multi-regional approach can be applied to distribution systems, which is of particular interest to this research. A further multi-regional example is suggested by Singh [136]. Here, a decentralised approach to congestion management using IP methods is used. The proposed model has the aims of allowing multi-utility or multi-country settings without the requirement of a common control centre. The aim is to allow the exchange of a small amount of information at interconnection points while maintaining safe system operation and independent dispatch decisions while benefiting the performance overall transmission area.

The method proposed is an AC load flow which uses a Karmarkar Interior Point solver. This differs from the classic IP method in that it moves through the interior of the feasible region, as opposed to following the boundary of the region. This helps to reduce the time taken to reach the optimal solution. The example used is a multi-regional transmission network similar to that currently in place in Europe however this could be scaled down and applied to distribution level thinking for the purpose of this research. The results of the test case have shown an improvement in congestion management problems via the use of a decentralized approach when compared with centralized, and when compared with a DC Load Flow solution. The cost and curtailment is reduced by using the proposed AC Load Flow solution.

Hazra [137] proposes a method which aims to minimize cost, congestion and the risk of cascading failures while staying within the physical and operational limits of the system. The risk of cascading failures is caused during congestion events by the exposure of over current relays to protection failures. Generators can suffer from insufficient reactive power support which can cause voltage drops which will lead to incorrect operation of generator protection systems. To meet these objectives, sensitivity factors are calculated to determine the most effective generators and loads who wish to participate in congestion management. This ensures the best operational strategy for the system and is explained further in [138]. Multi object particle swarm optimization method is used to minimize cost of operation congestion and risk of cascading failures. The best compromise solution is selected from a set of Pareto optimal solutions using fuzzy approach.

Wang [139] demonstrates the use of rule based feasibility evaluation and optimal dispatch according to market conditions for transmission system congestion management. The feasibility evaluation is used to determine whether a potential contract can be accommodated in the transmission network with respect to existing contracts, network constraints and conditions. The rule based expert system, shown in Figure 3-6 and Figure 3-7 below, is a computer system that emulates the decision making abilities of a human expert by adhering to a set of rules (IF, THEN, AND, ELSE statements…). Combining this with a 'Forward Chaining Inference Procedure', available data stored in a working memory database can be used to extract more data until a solution is reached.

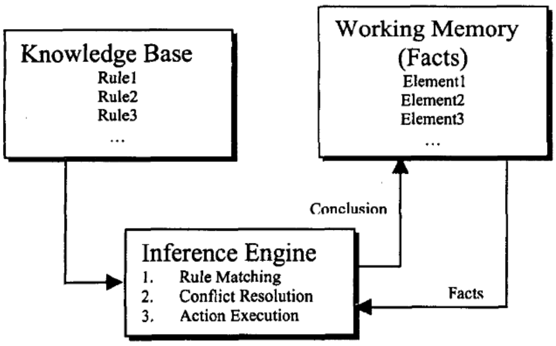

Figure 3-6 Rule based model [139]

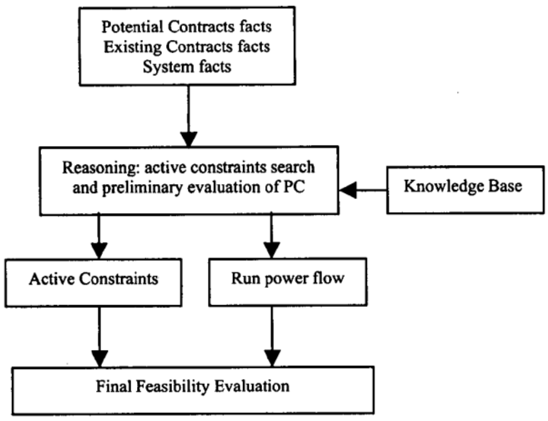

Figure 3-7 PC feasibility evaluation [139]

Generators are able to submit a 'willingness-to-pay' factor – a high value suggests the generator has a strong desire to remain connected to the network during a period of congestion. Simulation results presented by Wang demonstrate the importance of this 'willingness-to-pay' factor on curtailment levels for individual generators, and highlight the appeal of a market based access arrangement for renewable generation as the control rests in the hands of the generator – not the market operator.

There are a number of papers which discuss the use of OPF as a tool for both transmission [140], [141] and distribution planning [142]–[144]. The advantage of using OPF is that the true conditions of the network are considered. OPF has been further developed by others, and the full flexibility of the tool demonstrated by a number of authors. Keane et al [145] discuss state-of the art techniques for distribution planning. The authors note AC OPF as a powerful analysis tool. It is highly flexible and can be tailored to solve a number of problems by adapting objective functions and constraints. OPF advantages include the ability to consider not only thermal limits, but also fault level constraints [146], and voltage constraints [147].

Multi-period, or Dynamic Optimal Power Flow (DOPF) method was initially developed to analyse power systems dominated by hydrothermal generation [148] , however this tool has been developed to analyse energy storage [149], [150] and elements of electricity markets [151]. DOPF extends the OPF to apply to multiple time periods to improve the use of energy storage in ANM systems. The DOPF objectives are to minimize curtailment of renewable energy sources and minimize the use of conventional generation.

3.4.3 Tools to evaluate Curtailment Market design

Business models similar to those demonstrated by Environmental Change Institute [12] can be used to demonstrate the flow of goods, services, monetary and non-monetary elements of a market system. They provide a visual model to aid understanding of the process, flow of services and all parties involved as shown in Figure 3-8.

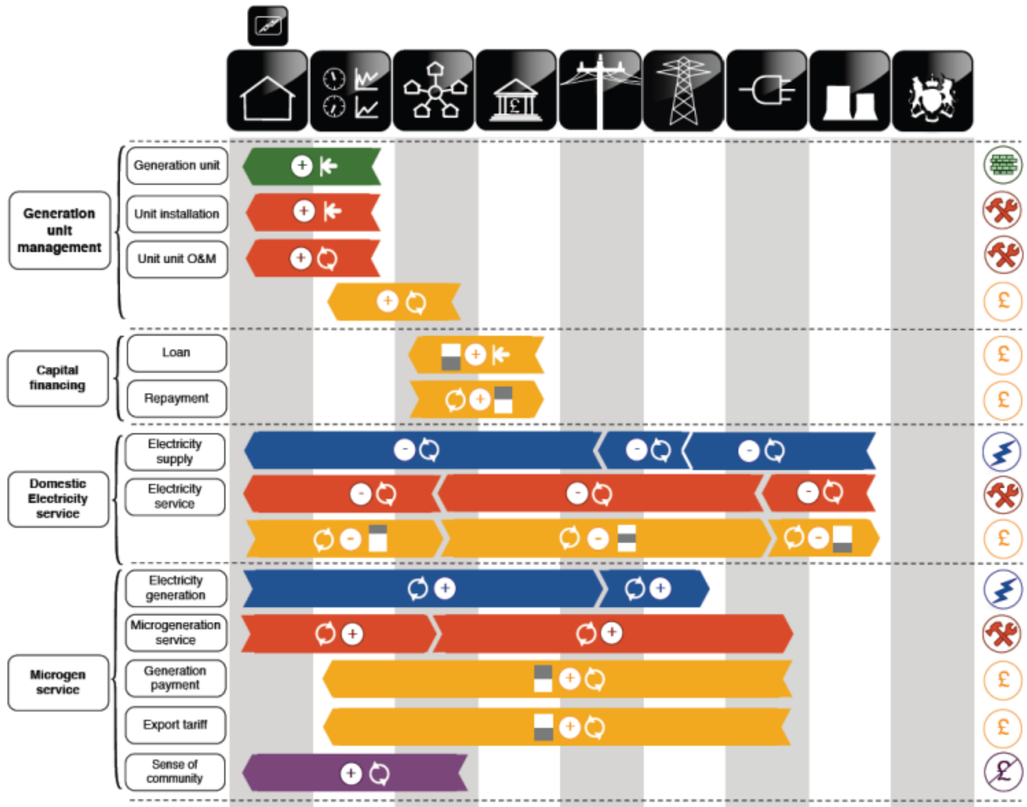

Figure 3-8 Business model of aggregation of domestic energy sources [12]

Game Theory can be used to study the efficiency of a new market design, and certain models can be applied to PoA solutions to determine the suitability and competition behaviour expected under new market rules.

The study of Oligopoly models is essential for the study of power system markets. An Oligopoly is a market dominated by a small number of sellers (oligopolists). Due to the small number of sellers, they are likely to be aware of the behaviour of other market players. The decision of one player can influence others, and vice-versa. Strategic planning by oligopolists must take into account the likely responses of other market participants. The market should encourage fierce competition which ensures low prices and high production i.e. close to perfect competition.

Game theory has been used in a number of studies to analyse the behaviour of generators in a constrained transmission system. Cunningham et al [152] demonstrate an empirical model which aims to represent the most realistic scenario by including non-symmetric market players, non-constant marginal cost, and asymmetric information. A number of models have used constant marginal costs, and assume all information is available to all generators – in a oligopolistic market this is not likely to be the case. Probabilistic analysis is used to determine the mixed strategy of generators.

The result of the model has shown that but applying a unidirectional constraint to a three-node system (with generation and demand at each node), the behaviour of market players changed even though the equilibrium flow in the absence of the constraint was less than the applied limit. Transmission constraints disrupt the pure strategy equilibrium and the outcome of market is much less certain – more issues will need to be considered in order to best determine behaviour of players.

Agent Based Modelling (ABM) is computational model for simulating actions and interactions of autonomous agents to assess their effects on the system as a whole. This modelling method allows us to experiment with market behaviour before applying changes to rules and regulations. Agent-based models can consist of intelligent agents who have learning algorithms incorporated into the scenarios. Multi-agent systems comprise of a number of intelligent agents interacting within a system. This is a particularly useful method of analysing the electricity market.

In terms of the electricity market, there might be a number of agents for generators and supply companies involved in the balancing mechanism. As the trading day goes on, the generator agent and supply agents will learn what bids and offers to make to ensure the highest level of accepted bids. A number of papers have been published on the use of Agent-Based modelling for simulation of the electricity markets. Pinto et al [153] discuss the use of Multi-Agent based simulator with VPP (virtual power plants). This method allows the integration of distributed generation into the electricity market. This paper provides a new architecture for MASCEM – Multi Agent System that Simulates Electricity Markets [154]. MASCEM provides a framework to assess new rules and arrangements in electricity market structures.

PowerWEB [155] is an internet based simulation environment for experimentally testing various power exchange auction markets using human decision makers. This method does not involve complex code creation that may be required with a number of other game theory methods as human participation is used instead.

3.4.4 OPF Computer Packages

There are a number of OPF packages available which can be used to determine the optimal PoA for a given network. These computational tools allow the users to apply a number of different OPF scenarios to large networks and analyse the results.

MatPower [156] is a package of Matlab [157] files which can be used to solve power flow and OPF problems. It was developed as part of the PowerWeb [155] project and includes a number of different solvers. A number of add-on packages have been developed to suit a number of different problems such as the TSPOPF package which includes three AC OPF solvers suitable for large scale problems and the IPOPT package which includes an interior point optimizer for large scale non-linear optimization using both AC and DC OPF.

Power System Analysis Toolbox (PSAT) [158] is a Matlab toolbox for power system analysis and simulation. A Simulink library provides a user interface for constructing power networks for analysis purposes. The main features of PSAT include: power flow, continuation power flow, OPF, small signal stability analysis, time domain simulation, complete Graphical User Interface, user defined models, FACTS models, wind turbine models, and conversion of data.

PowerWorld Simulator [159] is a power flow analysis package that is capable of solving large power systems. The package provides visualization techniques which are particularly useful when trying to understand a large network. There are a number of solution options including: full AC or DC solutions, the ability to run a single iteration at a time, loss penalty factors, convex cost curves and the ability to specify power-power flow solution actions.

PSS/E [160] is a software tool developed by Siemens with the aim of providing engineers with a tool to aid in transmission planning and operations. Highlights of the package include: power flow, OPF, fault analysis, dynamic simulation, open access and pricing, network reduction, and transfer limit analysis.

3.5 Chapter Three Conclusions

This chapter has presented a number of alternative PoA for implementation in an ANM scheme. The ANM case studies outlined in Chapter Two have trialled two out of the eight PoA listed in this chapter, In order to further investigate PoA and their impact on curtailment in ANM schemes, it is necessary to identify a number of other suitable curtailment arrangements. PoA are a key part of the ANM system as they determine the order and format of the curtailment. DNOs use this information to calculate the expected curtailment for any new generator connecting to the proposed ANM systems. Depending on the arrangement, there may be different impacts on the last generator to connect and this in turn will impact on the volume of feasible connection applications that could be accepted before curtailment levels are unacceptable to the developer.

The options were first split in to market or non-market arrangements to reflect the level of control generators and DNOs would have over the curtailment arrangement. The six arrangements selected for further analysis are:

- Non-market
    - Last In First Off
    - Pro Rata
    - Rota
- Market
    - Pay-as-Bid
    - System Price
    - Fixed Price

These six arrangements scored highly when assessed against established assessment criteria used for the design for regulatory frameworks. LIFO will be used as the base case against which the other arrangements will be compared. It is the arrangement used by most DNO's in the UK at the present time, therefore the results will provide a useful comparison to current ANM operation.

While the Pro Rata arrangement has some issues regarding long term guarantee of capacity factor, it can be assumed that a cap will be set on the maximum volume of capacity that can connect to any network under this arrangement. This is the approach adopted by UK Power Networks, and one which generators have accepted.

The Rota arrangement will operate on a 24hr rotation. The position of each generator on the LIFO stack will be moved one position up every 24hrs regardless of the volume of curtailment experienced. A more complex arrangement might consider rotating generators when a certain level of curtailment has been experienced however it is felt that by rotating every 24hrs there will still be a relatively fair distribution of curtailment between generators.

The review of electricity market design is used to determine the format of the three market PoA. Pay-as-bid and system price markets are widely used at transmission level and could be adapted to be used at distribution level for management of curtailment. The fixed price option will compensate generators using a single price based on subsidy payments. Further details of bid price calculations can be found in Chapter Four.

Logic commands will be applied to the OPF model to allow the bids to change after each 24hr period. The same market simulation is used for all three market PoA, with the difference being in how the compensation is allocated.

The evaluation techniques discussed in the later part of the chapter demonstrate the wide range of tools available for the analysis of PoA. An OPF method is used to apply both non-market and market PoA to a network case study. This method has been used in the past to apply constraint management techniques to networks, and is a valuable tool as it ensures the network is always within operation limits. Additional constraints can be added to OPF calculations and the solution aims to minimise cost and losses. Visual aids will be used to demonstrate the principles of the market arrangements, and also how the costs of ANM schemes can be recovered in the future when innovation funding is no longer available.

The following chapter provides further details on the modelling methodology and provides a simple four-bus example of the key attributes of the PoA discussed in this section.

4 ANM Principles of Access Modelling Methodology

4.1 Chapter Summary

Chapter Three provided a qualitative analysis of a number of PoA, and six arrangements have been identified as of material interest for further quantitative analysis: LIFO, Pro Rata, Rota, Pay-as-bid, Curtailment Market Clearing Price and Fixed Price.

OPF was selected in Chapter Three as being an appropriate tool to analyse the impact of PoA on generators as it has the ability to consider a number of network operational limits. This chapter will provide comprehensive detail and justify key options and decisions made in the modelling methodology which will be used to quantitatively assess the PoA.

The chapter begins by defining the modelling environment and the OPF formulations for each PoA. A step by step guide to the modelling algorithm is provided in addition to a full description of the market methodology. The details of how the OPF method is used to curtail generation in the stated order is explained and all assumptions and limitations of the model are clearly stated.

The chapter continues with a demonstration of the model on a simple network example. The key methods are demonstrated and the areas which will be focussed on for the real network study are highlighted here.

Finally, the model is validated using a spreadsheet calculation in the MS Excel application. The values of capacity factor which result from the OPF method are compared to those given using the Excel method to demonstrate that the model does in fact apply the curtailment arrangements in the appropriate order and at the required scale.

4.2 OPF Problem Formulation

The section outlines the technical aspects of the OPF problem including the optimisation method for the networks studied in this thesis, how the PoA are applied using the OPF method and a step-by-step guide to both the modelling of non-market and market arrangements. Further explanation of the design of the market methodology is also provided.

4.2.1 Modelling Environment

The simulations are run using MatPower [156]. This is a set of power system analysis functions run from within the MATLAB [157] environment. MATLAB is a high-level programming language and interface for numerical computation. MATLAB comes with a large number of inbuilt functions, and MatPower is a further set of functions developed by Zimmerman et al to be used for power system analysis.

The OPF function uses a standard MATLAB solver called MIPS, or Matlab Interior Point Solver. This is a primal dual interior point solver for general nonlinear optimization problems. The MIPS tries to solve the network, i.e. meet all the demand with the available generation, and stay within the limits in the network. These limits are defined in terms of thermal limits on circuits and voltage magnitude and angle at bus bars. It also tries to minimise the cost of generation and minimise network losses.

The MATLAB environment allows the user to both input and output data to Excel spreadsheets, and can also provide graph outputs if desired.

4.2.2 OPF Formulation

The aim of the OPF function is to minimize the cost of generation in order to meet the given demand, within the upper (u) and lower (l) limits of the network parameters. These include generator output limits (P_g), and voltage angle (Θ) and magnitude (V_m).

The OPF formulation is as follows

$$\min_x \sum_{i=1}^{n_g} f_P^i\left(p_g^i\right) \qquad \text{(eq. 4.1)}$$

Subject to the following constraints

$$P_G^{min} \leq P_G \leq P_G^{max} \qquad \text{Generator p limits} \qquad \text{(eq. 4.2)}$$

$$Q_G^{min} \leq Q_G \leq Q_G^{max} \qquad \text{Generator q limits} \qquad \text{(eq. 4.3)}$$

$$V_m{}^{min} \leq V_m \leq V_m{}^{max} \qquad \text{Voltage Limits} \qquad \text{(eq. 4.4)}$$

$$\Theta^{min} \leq \Theta \leq \Theta^{max} \qquad \text{Voltage Limits} \qquad \text{(eq. 4.5)}$$

The generator cost functions can either be piecewise linear or polynomial. A quadratic cost function has been selected in this case as this was the simplest way to apply curtailment to non-firm wind generation, where *c* is cost in £/MWh, *p* is generation output and *n*=3.

$$f(p) = c_n p^n + \cdots + c_1 p + c_0 \qquad \text{(eq. 4.6)}$$

For example, the cost function for one of the case study networks is

$$f(p) = \ 0.1p^2 + 5p + 1 \qquad \text{(eq. 4.7)}$$

The important property of the cost function is the rate of change, or gradient of the line. This gradient informs the OPF of the order in which to curtail generation. An example of cost functions used are shown in Figure 4-1.

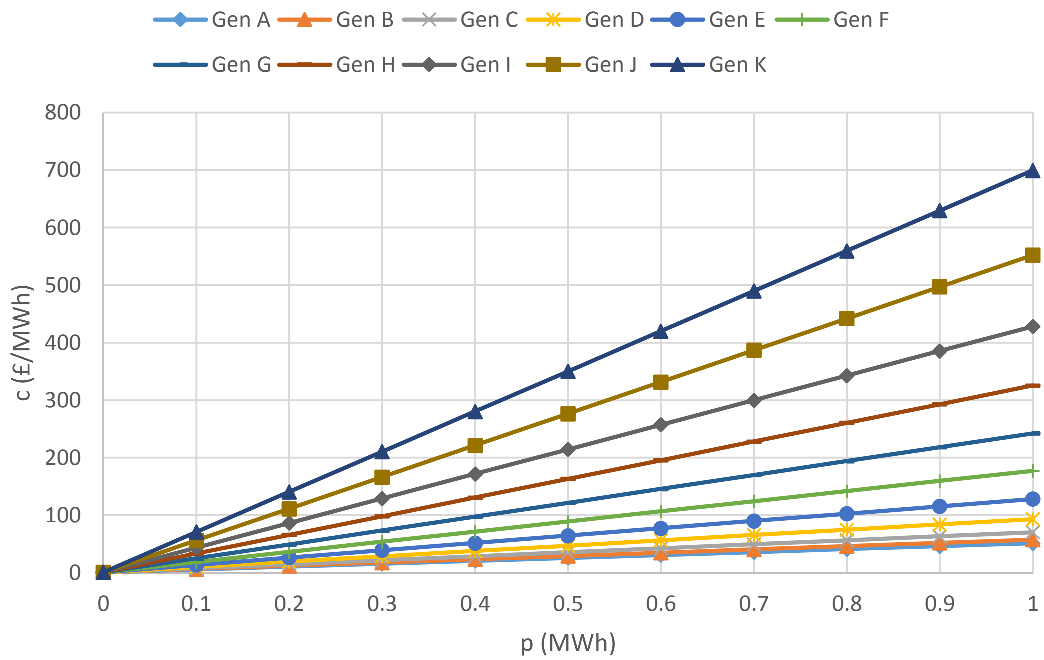

Figure 4-1 Graph showing cost functions used to apply a LIFO arrangement. The generator with the highest cost gradient will be curtailed first

The cost functions do not reflect the true cost of operation of generation, but are simply used to control the curtailment of generators on the network and influence the solution of the OPF analysis. Generators with firm connections are given a near-zero cost, and the slack bus (which is the grid supply point) is given a much higher cost gradient than all generation to discourage import from transmission system.

The diagram in Figure 4-2 demonstrates how curtailment is applied during a LIFO arrangement. The generators are prioritized based on date of connection i.e. the last generator to connect to the network will be given the highest OPF cost and will be curtailed first, followed by the second last generator to connect and so on until the constraint is cleared.

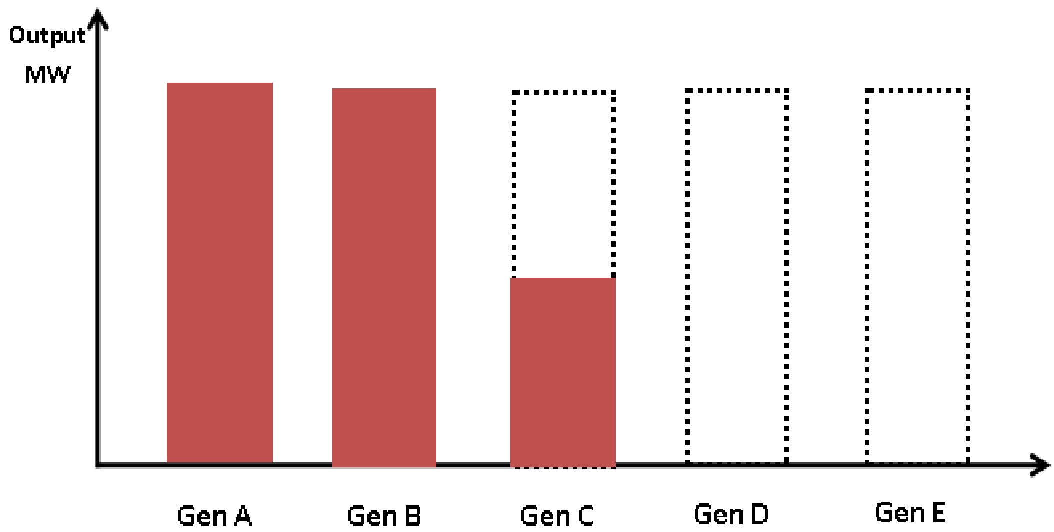

Figure 4-2 Diagram of how curtailment is applied during a LIFO arrangement

The Rota arrangement works in a similar manner, with the difference being that the order of curtailment is changed each 24 hour period in order to rotate the position on the priority stack. The diagram in Figure 4-3 explains how this PoA is applied. For example, on Day 1 Generator E is curtailed first but on Day 2 Generator E is moved to the top of the stack and Generator D is now first to curtail.

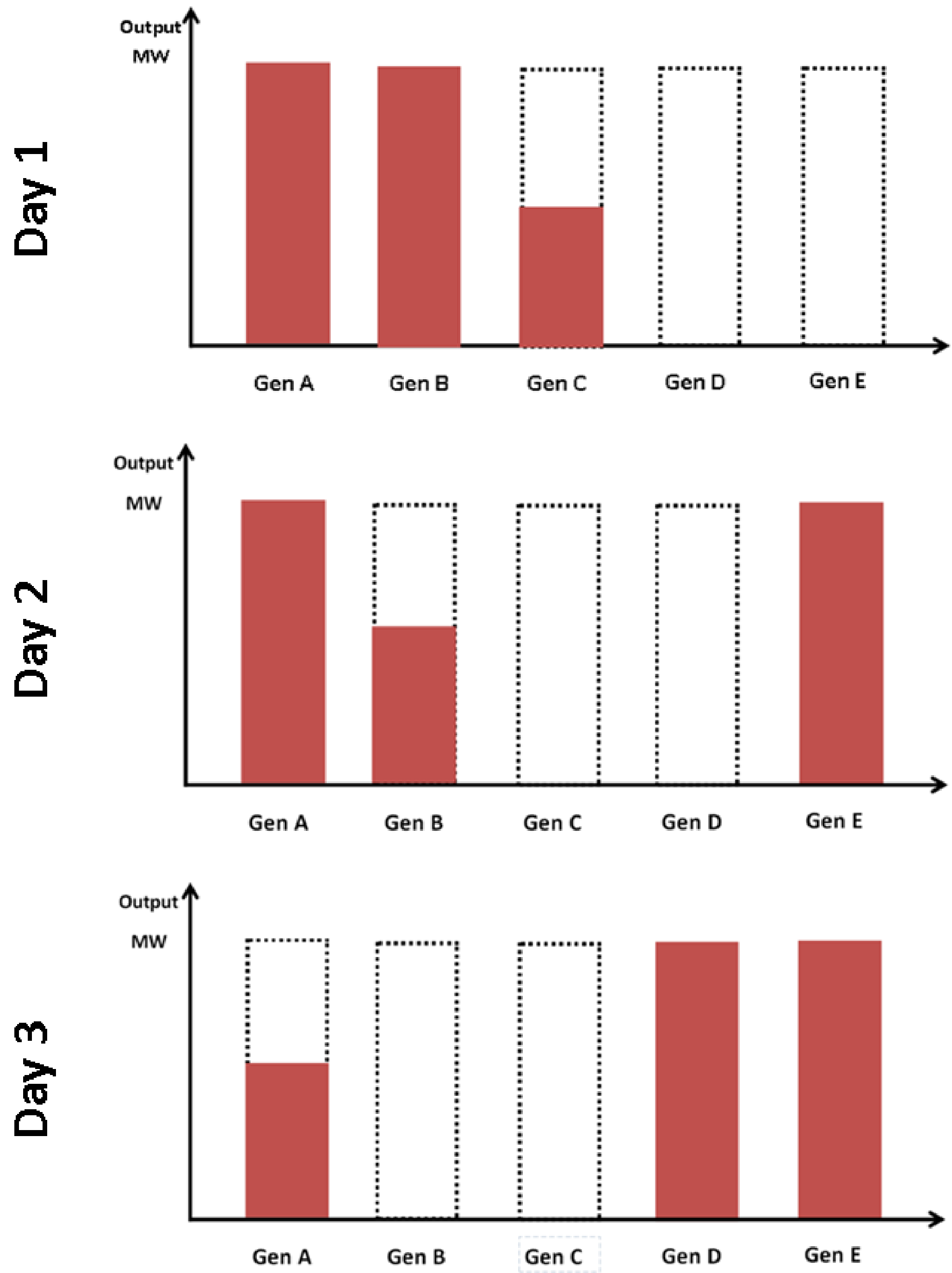

Figure 4-3 Diagram of how curtailment is applied during a Rota arrangement

In order to apply the Pro Rata arrangement, additional OPF constraints are applied to each zone. These constraints are designed to ensure all generators in each zone share curtailment based on the size of the generator output. In order to do this, additional constraints are added to the OPF formulation by relating the generators in each zone to each other.

For

$$Gen_{ref}Capacity = X \text{ MW} \qquad \text{(eq. 4.5)}$$

$$Gen_{i}Capacity = Y \text{ MW} \qquad \text{(eq. 4.6)}$$

$$Gen_{i}Output = \frac{Gen_{i}Capacity}{Gen_{ref}Capacity} \times Gen_{ref}\,Output \qquad \text{(eq. 4.7)}$$

Gen$_{ref}$ is the reference generator in the zone and *i*=1…n-1, where n is the number of generators in each zone.

For example, if there are five 1 MW generators behind a single constraint, and there is a maximum export of 3 MW. At full capacity, the output of the group of generators would be 5 MW therefore 2 MW of curtailment is required. This would be split evenly between all five generators, and their output would be reduced to 0.6 MW. This is demonstrated by the graphs in Figure 4-4. The percentage share is based on output at the time of constraint and not nameplate capacity.

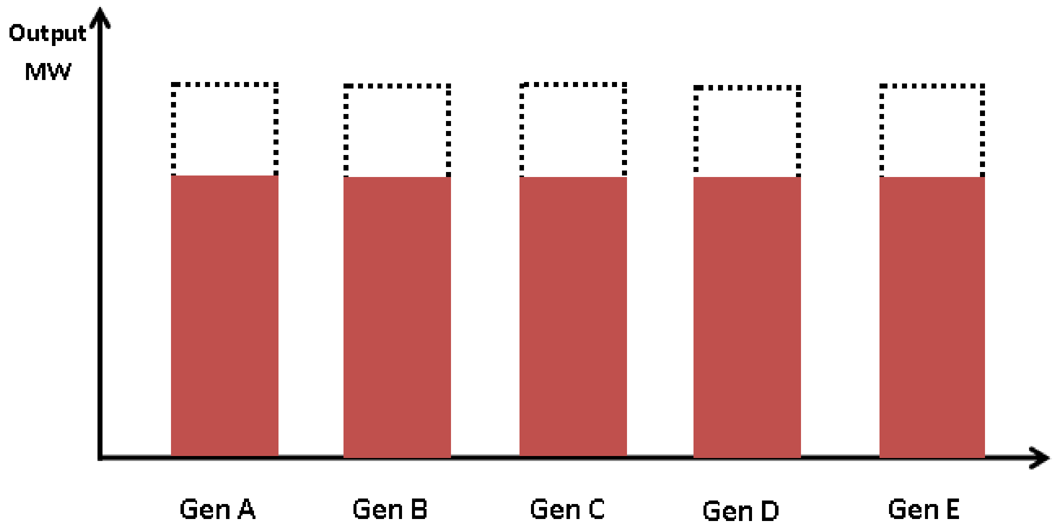

Figure 4-4 Diagram of how curtailment is applied during a Pro Rata arrangement

4.2.3 Market Methodology

The same OPF methodology is used for modelling market arrangements and additional logic commands are incorporated into the simulation to account for bid changes and profit seeking behaviour. An explanation of the 'dynamic pricing' method is explained below, followed by the calculation of the static or uncurtailed bid prices.

4.2.3.1 Dynamic Pricing

Generators submit bids to inform the network operator of their willingness to participate in a curtailment market. The bid prices are derived from a simple dynamic pricing method, as outlined below. This method uses simple logic to inform changes in bids, with the decision based on the amount of curtailment and compensation received previously. Generators are always aiming to make more than or equal to the profit they would expect to make if uncurtailed, referred to as the pre-curtailment profit in this work. The dynamic prices are always equal to or greater than the static prices for each generator. Note that both static and dynamic pricing use a single wholesale power price and do not reflect varying prices over time.

One day (midnight to midnight) is used as the time step for price changes. Curtailment events occur over short time scales, i.e. minutes or tens of minutes. The simulations use half-hourly time steps for curtailment assessment and daily bid changes as this was the exemplar data available. Generators therefore revise prices for tomorrow based on the current day's performance.

Static prices are used to set the bid at the first time step. These are also used to inform the 'uncurtailed profit' level. This level remains fixed through the simulation as the time period considered is no greater than one year throughout the examples given in Chapter Four and 5. Should a time period of greater than one year be considered, then this price may fluctuate based on interest rates or regulatory changes to subsidy payments.

This section is simply to demonstrate the process. Analysis and sensitivities of the method will be explored in greater detail in Chapter Five.

Step 1

In the first time step the starting bids are selected for each generator based on the price the generator expects to receive when uncurtailed e.g. four generators might have starting bids as shown on the right.

Name	Bid (£/MWh)	Capacity
Gen A	130	1MW
Gen B	119	2MW
Gen C	150	0.5MW
Gen D	125	1MW

Figure 4-5 Starting bids (£/MWh)

Step 2

The simulation 'stacks' the bids in order from least to highest cost. This sets the order of curtailment which will result in the lowest cost for system operator.

Name	Bid (£/MWh)	Capacity
Gen C	150	0.5MW
Gen A	130	1MW
Gen D	125	1MW
Gen B	119	2MW

Figure 4-6 Bids stacked in order from least to highest cost (£/MWh)

Step 3

The simulation will curtail generation in reverse order (from least to most cost). For example, if there is a 3.5 MW constraints then Generator B and Generator D are fully curtailed and Generator A is partially curtailed. Generator C experiences no curtailment.

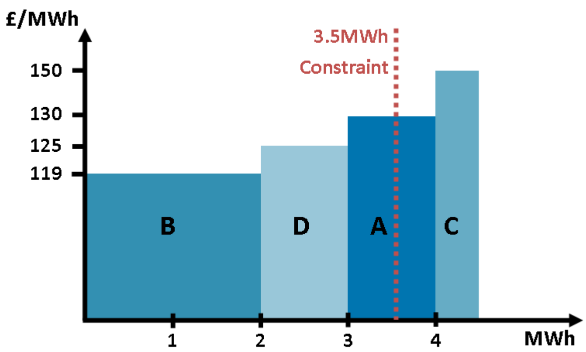

Figure 4-7 Diagram of generator curtailment

Step 4

At midnight generators make a decision on their bids for the next day. This is based on two things:

1. Level of curtailment experienced in the previous day
2. Level of compensation payments received (compared to revenue if uncurtailed)

The generators can choose to increase, decrease or hold their bid for the next time day. The decision logic is shown in Table 4-1 below. Some decisions are based on using a random number, where a value between 0 and 0.5 is rounded to 0 and a value between 0.5 and 1 is rounded to 1. This is then multiplied by 5 to get the bid step change, i.e. the result can be 0 or 5, as shown below. The randomisation of the number is to reflect the decision making behaviour of real participants in the market. Rounding the number results in regulated step changes of the bid i.e. either an increase or decrease of the same value.

For example, if Generator B is fully curtailed for most of a day, and the compensation received was higher than the static price then Generator B will either choose to hold its bid the same as the previous day, or increase the bid by £5/MWh. In contrast, if Generator C is mostly uncurtailed when its bid was higher than its static price, for the next day Generator C can choose to hold its bid or drop the bid by £5/MWh.

Table 4-1: Decision logic for dynamic pricing method

	Payment > Precurtailment Revenue	Payment = Precurtailment Revenue	Payment < Precurtailment Revenue
Fully Curtailed	+ 0 or 5	+ 5	+ 5
Partially Curtailed	- 0 or 5	+ 0 or 5	+ 5
Uncurtailed	- 0 or 5	+ 0 or 5	+ 0 or 5

Step 5

Generators submit their bids and the process repeats from Step 2.This method starts with prices based on the value of energy produced and then each day increases or decreases the price of each resource based on whether it was curtailed and the prices paid in the previous day. The decision on whether to increase/decrease prices can include a random element to give some diversity of behaviour amongst market participants. In a simple way it simulates price elasticity by increasing prices when demand (for the constraint service) is high and decreasing them when demand falls, except that elasticity is restricted so that the dynamic price does not drop below the static price.

The two market models only differ in the price paid for compensation. Under Pay-as-bid (PAB), the compensation is equal to the submitted bid for the time period i.e. the bid placed during the day which curtailment was applied. Under a Curtailment Market Clearing Price (CMCP) arrangement, an additional calculation is required to determine the curtailment clearing price. If generators are fully or partially curtailed in a CMCP market, they will all receive the same price. It can also be assumed that if a generator is fully curtailed, the bid was less than or equal to the CMCP, and, if partially curtailed, the bid was equal to the CMCP. Therefore it is possible to use the results from the PAB modelling to calculate the cost of curtailment in a CMCP market.

Generator bids are adjusted for the next time period by comparing the clearing price to the pre-curtailment profit level. The calculation of this value is explained in Section 4.2.3.2. For example, in Figure 4-7 the last generator to be curtailed is Generator A. This will make the system price £130/MWh and this will be awarded to Generators B and D as compensation.

4.2.3.2 Pre-curtailment Revenue

To calculate the pre-curtailment costs for generating units, the following equation is used

$$Lost\ Revenue = Electricity\ Price + FIT + Embedded\ Benefits + LEC \qquad [1]$$

The four components of the Lost Revenue calculation are explained in further detail below. This equation is based on the method used by Baringa and UK Power Networks in their own calculations of lost revenue [10] for the FPP project.

Electricity price is based on Redpoint Energy GB Power Market report (April 2012) [10]. The average electricity price of £58.50/MWh is applied in all cases for the market model studies.

The FIT subsidies are available on the Ofgem website [161], as are the ROC tariffs (see Section 2.3.3). The tariff used is based on the assumed connection date of the wind generators which was between 2009 and 2012. The ROC values used are based on those used by Baringa in [10].

Table 4-2 Feed-in Tariff [161] **and ROC price based on values in** [10]

	Capacity	Feed-In Tariff	ROC
	kW	**£/MWh**	**£/MWh**
Wind	<1500	107.20	-
Wind	>1500	50.50	-
Wind	>5000	-	40.30

The Levy Exemption Certificates (LEC) provides energy suppliers with evidence that renewable energy sources are used to supply the UK customers with renewable electricity. It is linked to the Climate Change Levy, which is a tax applied to UK business energy users [162]. Renewable generators are entitled to claim the LEC. The current rate is 0.541p/kWh [163]. Embedded benefits include the cost of avoided Transmission Use of System charges, Balancing Service Use of System charges, and transmission losses. Baringa estimate these to be £5.5/MWh [10]. These reductions are in place to reward generators who connect close to the load.

There are discounts applied to all of these components as part of the PPA agreement. This agreement is a long term contract between a generator and a supplier. The agreement ensures a guaranteed price per unit of electricity for a stated amount of energy over a set period of time. The discount accounts for generators and energy suppliers agreeing to a long term price guarantee. For FIT generators, a 10% discount is applied to payments for power and LECs [10] .For example, a 2.3 MW turbine would have the following costs applied:

Table 4-3 Example pre-curtailment costs for 2.3 MW wind turbine

	Electricity Price	Feed-in Tariff	Embedded Benefits	LEC	Total
2.3 MW Wind Turbine	58.5 x 90%	50.5	5.5	5.41 x 90%	£113.52 MWh

The total cost given in the right hand column would be used as the starting bid for the market based PoA simulations.

4.2.4 PoA Curtailment Calculation Methodology

This section will provide a detailed description of the modelling algorithm, and the inputs and outputs associated with the simulation. A flowchart of the modelling process is shown in Figure 4-8.

The input for the model consists of representative time series data for demand and generation in half hourly intervals. A similar approach has been used by MacDonald and Foote in [164]. The overall curtailment results would not vary by using a higher frequency of data such as 15 minute or 5 minute data. The wind profile is applied to all renewable generation across the network – meaning all wind generators have the same capacity factor during each half hourly interval before any curtailment is applied. This is not an accurate depiction of the behaviour of wind generator output across a power network. There is likely to be variation across the geographical area of wind speeds, however the aim of the model is not to provide an accurate depiction of the system behaviour but to discover the relative merits of the options for PoA in a particular network. For other types of renewable generators, the appropriate export profiles are applied. The user also must select one of four options for applying a PoA: LIFO, Pro Rata, Rota or market. Both PAB and CMCP market arrangements will provide the same result in terms of curtailment but the cost for CMCP is calculated in post processing. The model is run for individual months, or as a whole year in a single command. When a market scenario is simulated, then a list of 'pre-curtailment' revenue is required as an additional input when compared with the non-market arrangements.

Regardless of the total time period analysed, the simulation addresses each 30 minute time period as a discrete event and runs a power flow analysis to determine if there is any congestion on the network. To do this, the power flowing through each branch is compared to the line ratings stipulated in the network model. When the power flowing through a line exceeds the static thermal rating, the branch is classified as constrained and will need to be resolved in the next step of the analysis. Typically, conductors will be allocated 'Seasonal' ratings for the thermal limits. The rating is related to the temperature of the air surrounding the conductor and is set based on maximum allowable sag of conductors. Research and trials have been carried out in to the use of dynamic line ratings, where the rating will change based on local temperatures. For the purpose of this analysis, a static rating is used to determine constraints.

If there is no congestion on the network during a time period, then the model will store the results and move on to the next time period.

When there is an active constraint on the network, the OPF solver will curtail required generation and return the network to a safe operating state. The objective function of the OPF is to meet demand with the available generation on the network, at the lowest possible cost. The identification of congestion and the application of constraints occur in two separate processes in order to prevent the costs applied for OPF from influencing network behaviour during unconstrained periods.

When generation has been curtailed and the network is operating within limits once again, the model will store the results and move on to the next time period. The output will give details of generator outputs pre and post curtailment, network losses, import/export, the slack bus and any relevant bid behaviour information.

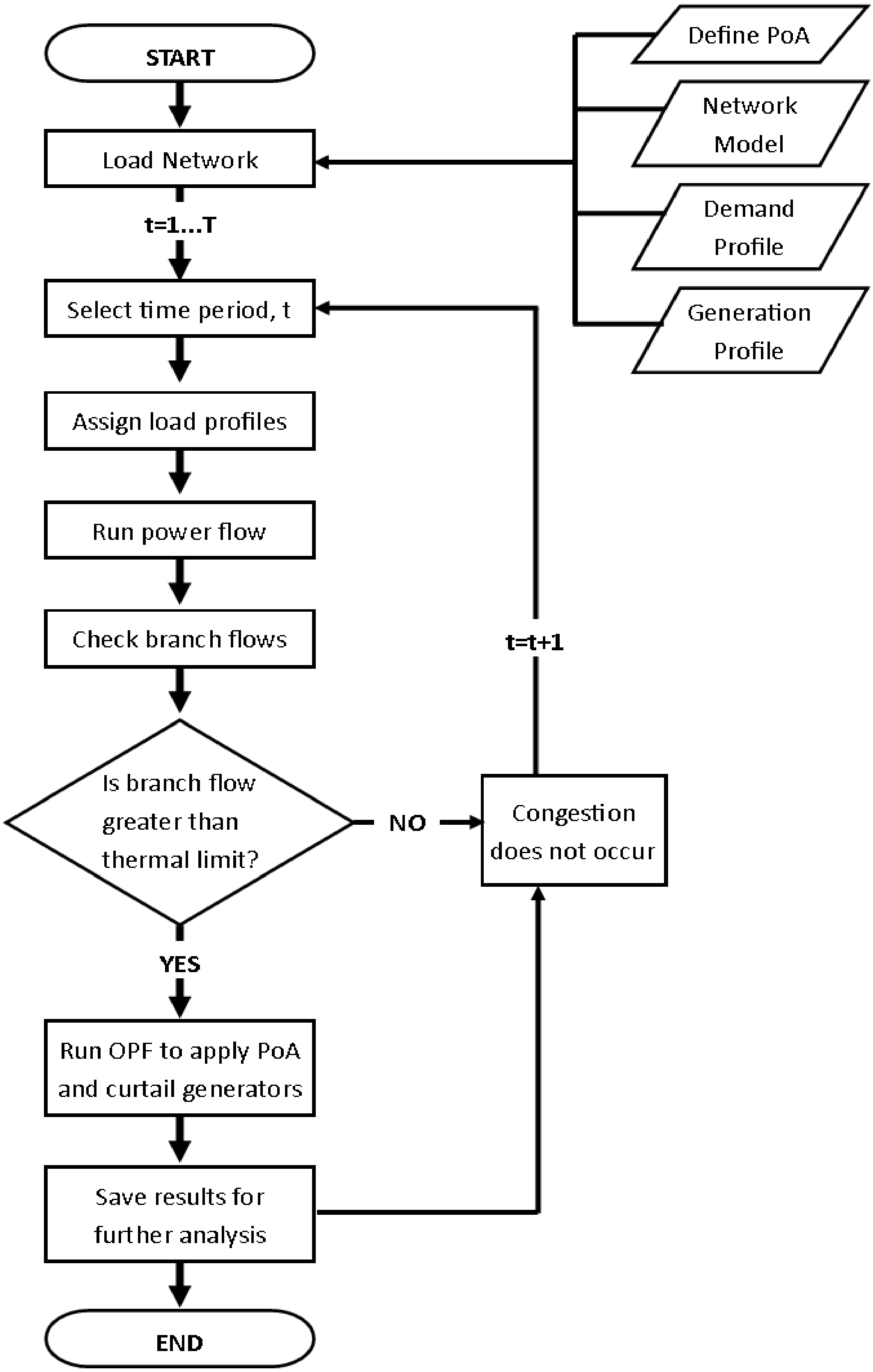

Figure 4-8 Annual Constraint Analysis Modelling Process

4.2.5 Assumptions and Limitations

A number of assumptions have been made and the model has some limitations.

Unity power factor is assumed for all generators. There is zero reactive power applied at demand buses. While this is not reflective of true network operation, the curtailment study only assumes real power thermal limits. In future, if voltage limits were to be considered, appropriate reactive power levels would need to be included.

In relation to this, there are no voltage constraints on to the network – only thermal limits. Reactive compensation devices are used to ensure there are no voltage issues on the network.

It is assumed that PAB and CMCP markets will give similar results for the curtailment of generation. The difference between the markets will be in the compensation paid to generators. Generators manipulate bids for the next time step based on curtailment in the previous time step. Generators who are curtailed can be assumed to have the lowest costs and may choose to remain at that bid, or increase that bid in the next time step. Generators who are fully or partially curtailed can be assumed to have the same as, or less than the CMCP and would therefore, also choose to stay at the current bid level or increase their bid for the next time step.

In order to ensure the curtailment order is applied in the correct order, the difference in gradient between non-firm generators increases by a power of 2.7 (See the graph in Figure 4-1). The reason for this is due to high losses on the network. The losses on the network interfere with the OPF solver and overrule the objective function to minimise cost, in order to reduce network losses.

The costs used in the market model are simplistic, as are the logic controls used to determine new bids. While more complex methods, such as Agent Based Modelling, may be more appropriate in determining market behaviour they do not consider network properties. The continuation of the OPF methodology in modelling the market arrangements ensures a consistency across the modelling approach.

4.3 Demonstration of PoA on a Simple Network Model

Combining the discussions from section 3.2 and 3.3, some basic principles of PoA modelling will be demonstrated in this section. The aim of the examples is to demonstrate the key impacts of different PoA on the capacity factor of wind generation before the main case study is presented in Chapter Five. The examples will not only demonstrate the different PoA but also demonstrate some sensitivity such as change of curtailment order under LIFO and different locations for generators and constraints.

In the examples, a variation of the network topology shown in Figure 4-9 will be used. This includes variations in location and size of constraints, line impedances and network topology. In all cases, there is a 10 MW firm, always-on generator and a variable load is connected to Bus 3. The slack bus is allocated to Bus 1 and there are five non-firm wind generators connected to the network, with a total nameplate capacity of 13.1 MW. A constraint will be created on the network, which will limit the output from some or all of the non-firm wind generators. To meet the demand at Bus 3, the network is set up to use the firm generator capacity at Bus 3 first and then use the available non-firm wind generation. The OPF cost of the slack bus is set high to allow the demand to be met by firm and non-firm generators connected to the network, as opposed to importing from external sources. This represents the 'must take' nature of renewable generation. The examples used in this study do not include storage and focus on the use of wind generation. In future, alternative energy sources could be added to the model so long as suitable profiles were available to represent particular outputs of the storage or other renewable generation.

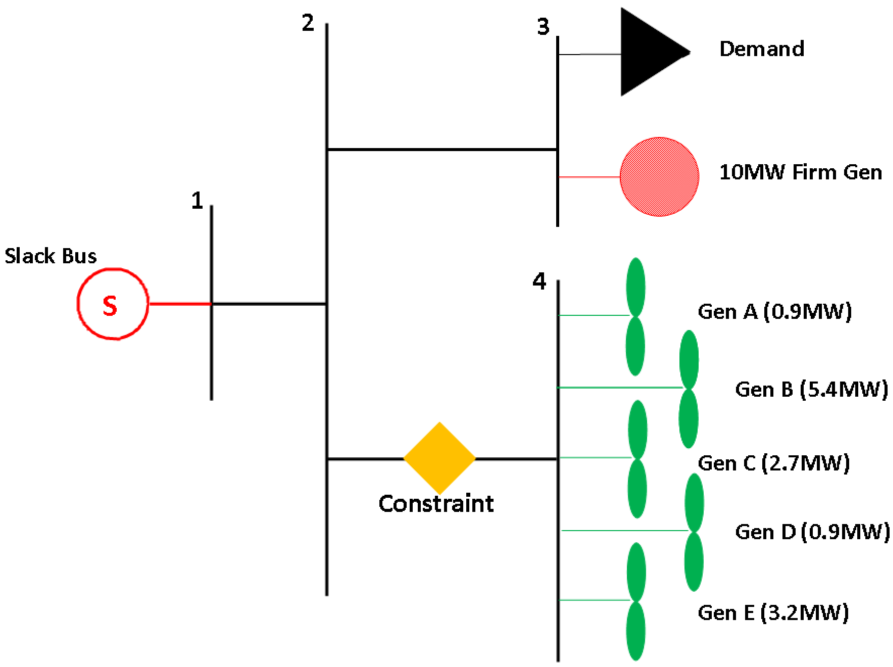

Figure 4-9 Exemplar network topology

The analysis is run over a one month period, with representative demand and wind profiles used. The profiles are shown in Figure 4-10 . There are 1,488 half-hour time periods in total.

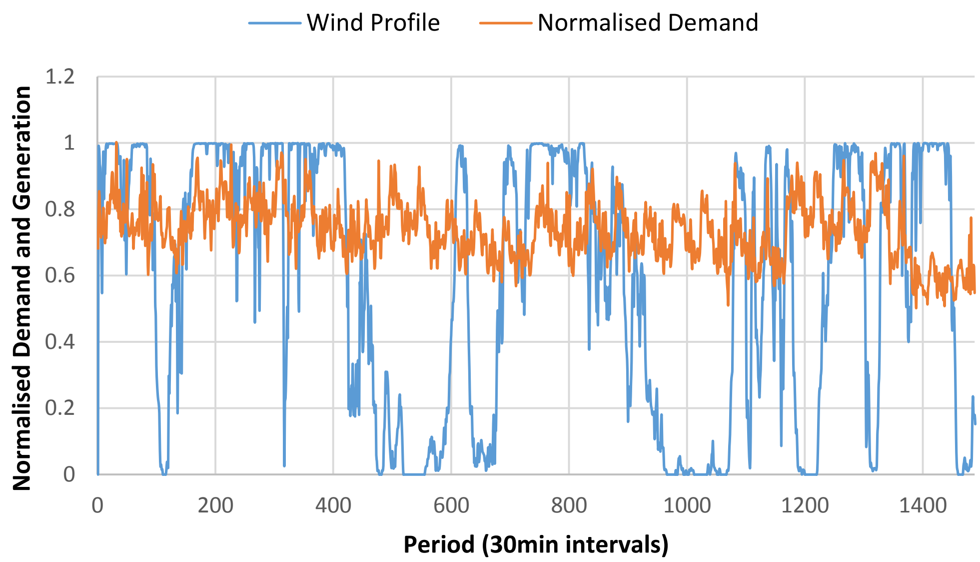

Figure 4-10 Normalised wind and demand profiles used in simple example

The non-firm wind generators have individual nameplate capacities ranging from 0.9 to 5.4 MW. The pre-curtailment profit for each of the wind farms is shown in Table 4-5. These costs are calculated using the method discussed in Section 4.2.3.2.

The calculation is shown in Table 4-4. Generator B is the only generator to receive ROCs, the other four generators receive FITs. It is evident from the table that the smaller turbines receive the highest price per MWh.

Table 4-4 Pre-curtailment profit calculation for example generators

	Capacity (MW)	Support Scheme	Electricity (£/MWh)	FIT tariff (£/MWh)	ROC value (£/MWh)	LECs (£/MWh)	Embedded benefits (£/MWh)	Totals (£/MWh)
A	0.9	FIT	58.50	107.2	-	4.87	5.50	**176**
B	5.4	ROC	58.50	-	40.30	4.87	5.50	**109**
C	2.7	FIT	58.50	50.5	-	4.87	5.50	**119**
D	0.9	FIT	58.50	107.2	-	4.87	5.50	**176**
E	3.2	FIT	58.50	50.5	-	4.87	5.50	**119**

A summary table of generator details is provided in Table 4-5. The priority order given will be used for initial LIFO studies. If the priorities stack changes, this will be stipulated in each case study discussion in the next section.

Table 4-5 Summary of generator details for two bus example

	Capacity (MW)	Priority Order	Pre-curtailment Profit (£/MWh)
Gen A	0.9	1	176
Gen B	5.4	2	109
Gen C	2.7	3	119
Gen D	0.9	4	176
Gen E	3.2	5	119

4.3.1 Studies of PoA on a Simple Network

Three studies are carried out on the different PoA. In all studies, the capacity factor of the three non-market arrangements is compared, and for the market arrangements the focus is placed on the cost of curtailment compensation. The aim of these studies is to present the key impacts of several PoA on a simple network example with zero to minimal losses before applying PoA to a more complicated, real network example.

Study A features a single constraint located on the branch that connects the five non-firm wind generators to the rest of the network. Study B will assess the impact of local constraints with only three of the five generators located behind a constraint. Finally in Study C, line impedances are applied to the five non-firm generators behind a single constraint to simulate the behaviour of a large network with high losses that would impact on the level of curtailment required.

4.3.1.1 Study A: Single Constraint

In this example there is an 8 MW limit on the branch between Bus 2 and 4, and all five non-firm generators are located behind the same constraint. The network topology is shown in Figure 4-11.

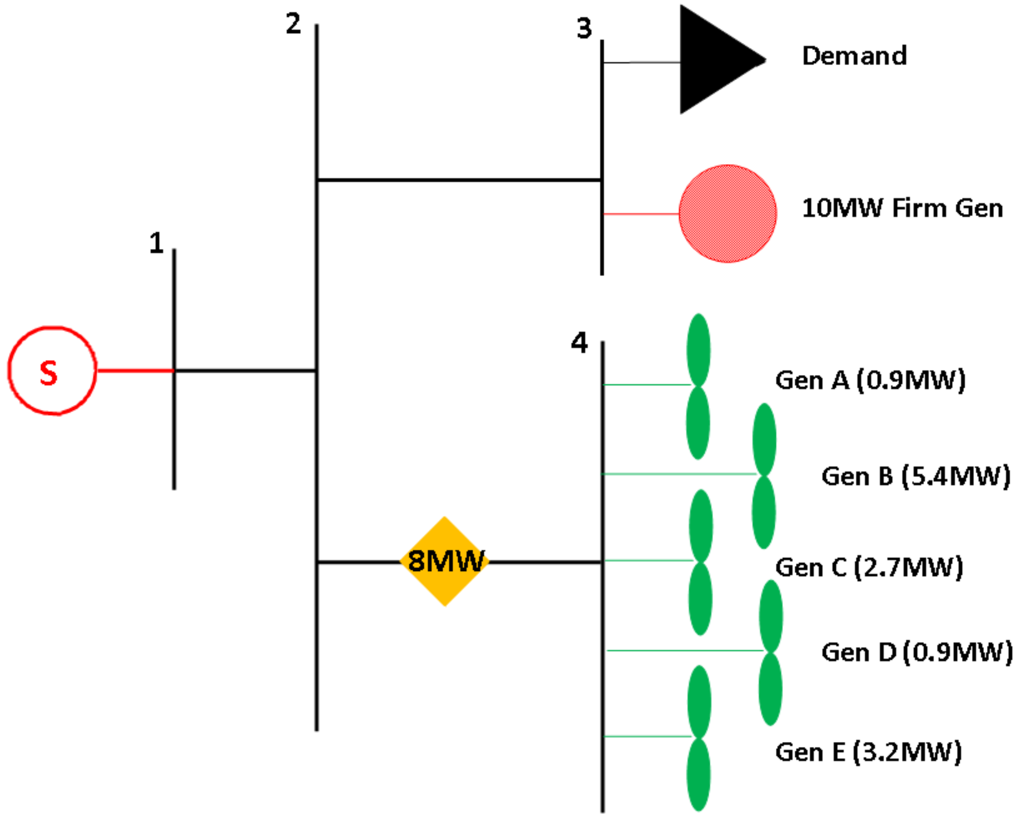

Figure 4-11 Study A: Network diagram

When the Pro Rata PoA is utilised, the following constraints are applied

$$Gen\ B = 6 \times Gen\ A \qquad \text{(eq.4.8)}$$

$$Gen\ C = 3 \times Gen\ A \qquad \text{(eq.4.9)}$$

$$Gen\ D = 1 \times Gen\ A \qquad \text{(eq.4.10)}$$

$$Gen\ E = 3.56 \times Gen\ A \qquad \text{(eq.4.11)}$$

These conditions mean that when a constraint occurs, all generators will be curtailed by a percentage relative to their output at the time the curtailment is required.

The results in Figure 4-12 demonstrate the share of curtailment for the three non-market PoA and a market PoA. The different market mechanisms are shown here as one group as the difference is simply the price paid for curtailment compensation, the choice of generator to curtail will be the same i.e. the generator with the lowest bid. There are 814 instances of curtailment during a 31 day period and a total of 1,636 MWh energy curtailed.

Based on the priority order given in Table 4-5, Generator E is first to curtail and is subject to the majority of curtailment under a LIFO arrangement. Pro rata and Rota arrangements lead to a balanced share of the curtailment between the five generators. In a market arrangement, the largest generator, Generator B, submits to lowest bid price per MWh and is therefore selected by the OPF model to clear the constraint to minimise the cost of constraint payments.

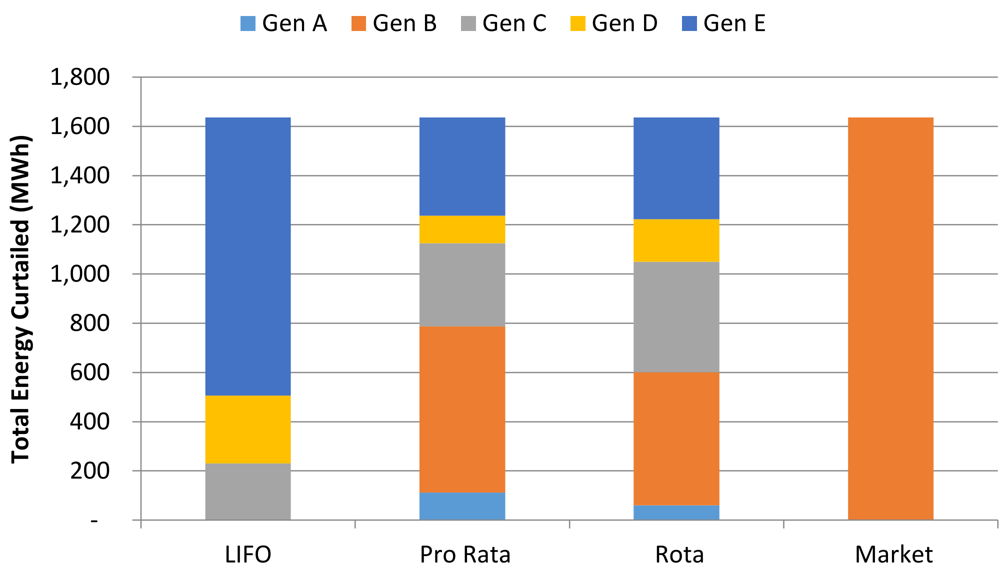

Figure 4-12 Total energy curtailed for Study A

The average monthly capacity factors are shown in Figure 4-13. The LIFO arrangement results in the lowest capacity factor of 0.11 for Generator E. This is significantly lower than the uncurtailed average of 0.59 for the month studied. The Pro Rata and Rota arrangements result in similar average capacity factors and the curtailment is distributed between all wind farms either simultaneously as with the Pro Rata arrangement, or by changing the order every 24 hours under a Rota arrangement. The Pro Rata capacity factor is 0.42 and the Rota capacity factor ranges from 0.33 to 0.50. This range of capacity factor results occur because some generators are selected for curtailment during periods where there is more curtailment required, when compared with other time periods. The market scenario gives the best outcomes in terms of average capacity factor and cost of curtailment. It reduces the loss to the generator in terms of curtailment but also in terms of profit. This is because the market scenario will curtail the generator with the lowest cost. For the constraint in this network example, it can be cleared using the same wind farm.

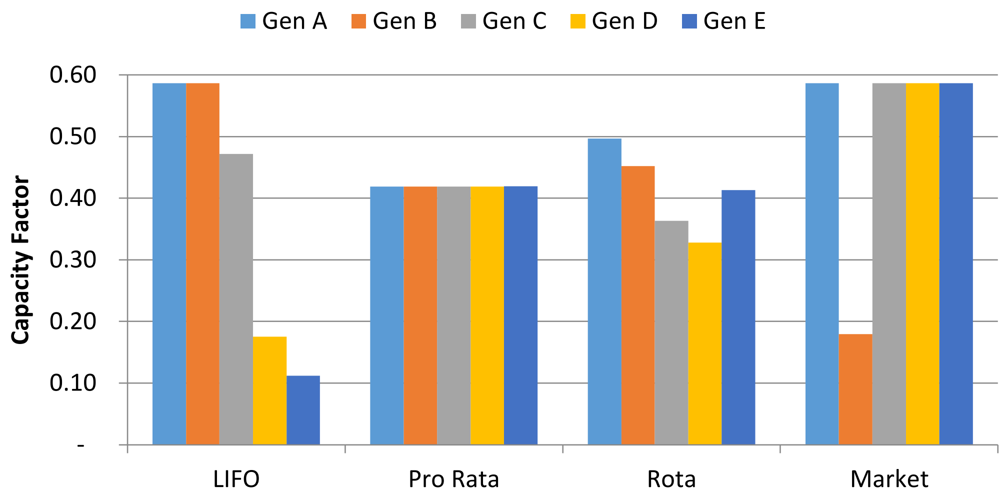

Figure 4-13: Study A Results: Impact of capacity factor on non-firm wind generators in a four bus network with a single constraint

The bid behaviour associated with the market arrangements is shown in Figure 4-14. As explained in Section 4.2.3, new bids are resubmitted after each 24 hours period, depending on the curtailment applied in the previous 24 hours and the level of payment made compared with potential un-curtailed earnings. Bids will either increase or decrease by £5/MWh or stay the same. The behaviour is relatively stable as no extreme bids are placed by any generators. Generators tend to seek bids in the region they set the initial starting bid and compete with generators at a similar cost level, and therefore with generators of a similar size and technology. The CMCP is also shown in Figure 4-14. There are points on the graph where it appears that the CMCP is higher than the lowest bid, however this occurs during periods of no curtailment on the network. This can be seen in Figure 4-10, by the periods where the wind profile dips below the demand profile.

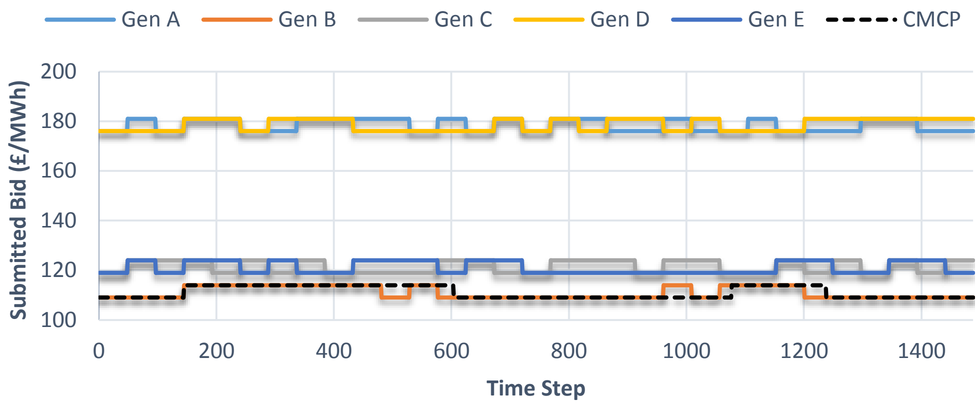

Figure 4-14 Study A Results: Dynamics of submitted bids

The total and average costs of curtailment are shown in Figure 4-15 and Table 4-6. The costs associated with the non-firm arrangement are purely for indicative purposes, no compensation would be paid to generators under these arrangements.

The LIFO arrangement has the highest average and total constraint costs. This is a result of using Generator E to clear the majority of curtailment. This generator has a high cost when compared with other generators (see Figure 4-15). Both market arrangements give the same cost of curtailment, as Generator B is used to clear all constraints across the analysis period. The Pro Rata and Rota arrangements have similar costs, as the curtailment is shared between the non-firm generators across the analysis period and therefore the costs vary accordingly.

Table 4-6 Study A Results: Total and average curtailment costs for each PoA

	LIFO	Pro Rata	Rota	PAB	CMCP
Total Constraint Costs (£k)	210	201	203	182	182
Average Constraint Costs (£/MWh)	129	123	124	111	111

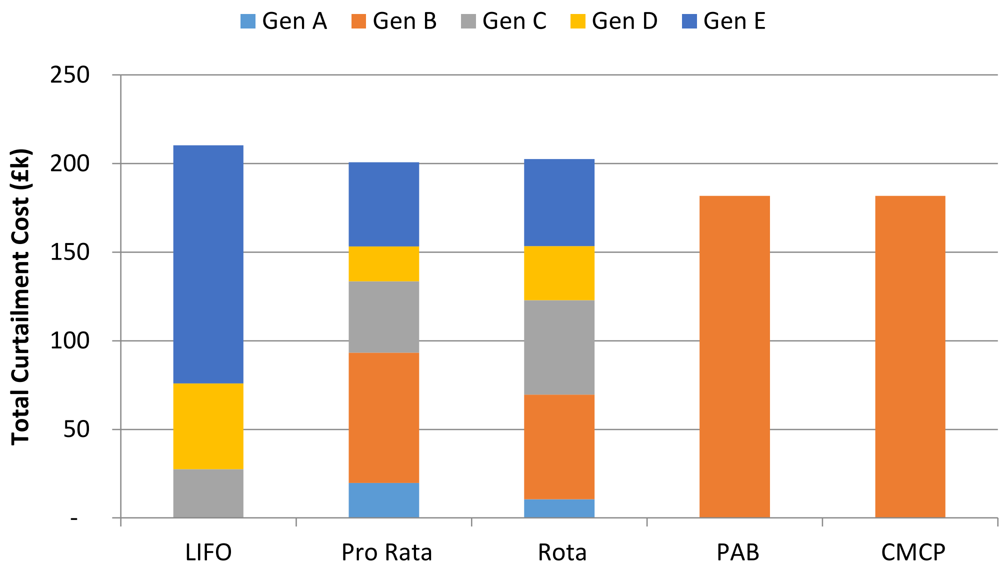

Figure 4-15 Study A: Total curtailment costs (£k)

To demonstrate the sensitivity of the size of generators and their order in the priority stack the position of Generator A and Generator E have been switched. Generator E is a relatively large generator with a capacity of 3.2 MW, so when it is at the bottom of the priority stack, it will in most cases be the marginal generator and clear the majority of constraint. If the order the priority stack is changed to switch the position of Generator A, with a capacity of 0.9 MW, and Generator E then there are now more generators subjected to constraints and Generator C or Generator D becomes the marginal generator. The results of this sensitivity study are shown in Figure 4-16.

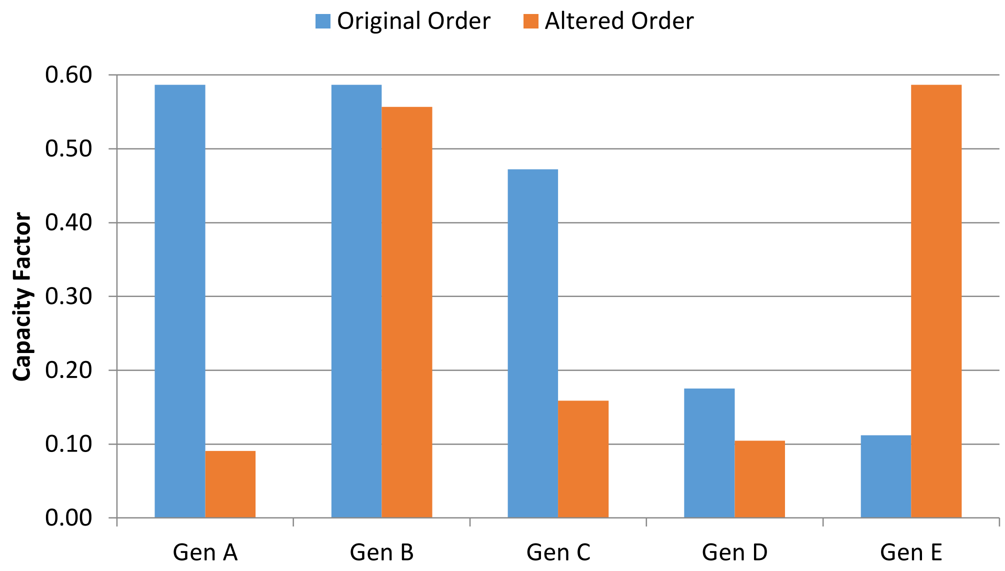

Figure 4-16 Graph showing the impact on capacity factor when the priority stack order is changed. Generator A and Generator E have had their positions switched in the second series.

When there are smaller capacity generators at the bottom of the curtailment stack, the curtailment will affect more generators. Generator E is more than three times the capacity of Generator A and therefore the curtailment of generators further up the stack, such as Generator B is increased. Stacking generators by order of size would be considered discriminatory and discourage larger, possible more efficient generators from connecting to the network. However, the impact on overall curtailment is evident from this short study and the size of the marginal generator will play a significant role in determining curtailment in any ANM scheme.

4.3.1.2 Study B: Local Constraints

In this example, Bus 4 is split to create a fifth and sixth bus. Two generators are connected to Bus 5 and three generators connected to Bus 6.

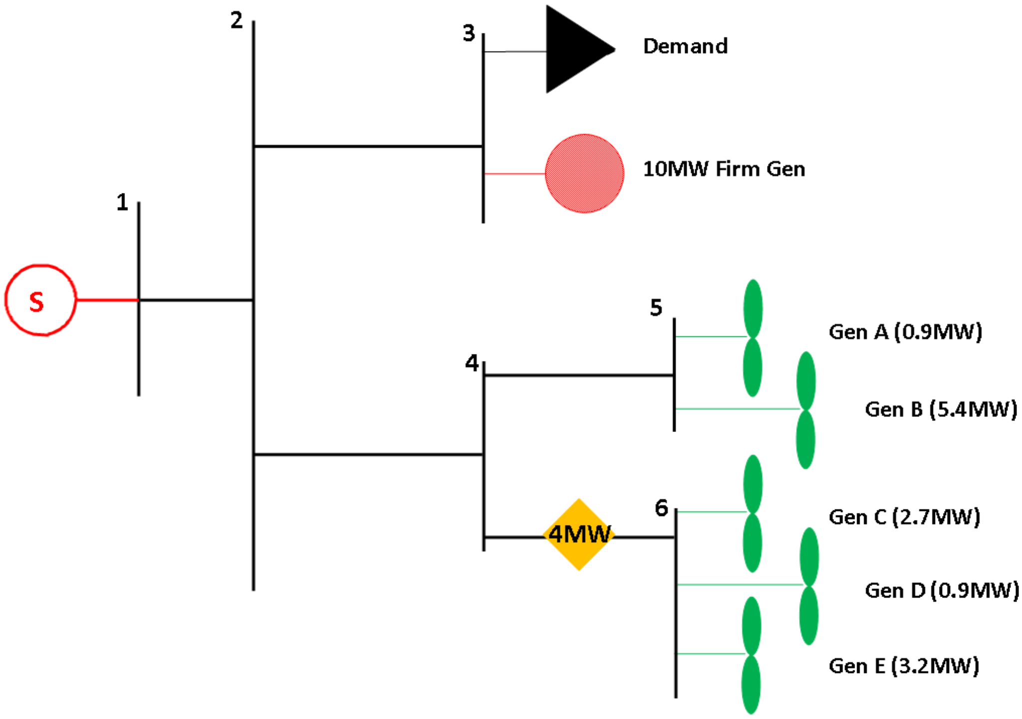

Figure 4-17 Five bus example with local constraints

The line limit on the branch between Bus 4 and 6 is 4 MW. Now, only Generators C, D and E are constrained on the network, and Generators A and B unconstrained. This results in 834 instances of constraint, a similar number of time periods as presented in Study A. The total curtailed energy is only 912 MWh, compared to the 1,636 MWh curtailed in Study A. As a percentage of the generation connected behind the constraint, both Study A and Study B curtail 12-15% of the uncurtailed output.

During the Pro Rata PoA the following constraints are applied

$$Gen\ C = 3 \times Gen\ D \qquad \text{(eq. 4.12)}$$

$$Gen\ C = 0.84 \times Gen\ E \qquad \text{(eq. 4.13)}$$

These equations mean that when a constraint occurs, all generators will be curtailed by a percentage relative to their output at the time the curtailment is required. The total curtailed energy is shown in Figure 4-18. This figure demonstrates the impact of having the constraint localised. Only Generators C, D and E are curtailed in this study. These results demonstrate that for any new generators wishing to connect to the network may choose not to connect at Bus 6 in order to avoid higher curtailment levels when compared with Bus 5. New connections could still be facilitated at Bus 6 but they would experience less curtailment behind Bus 5.

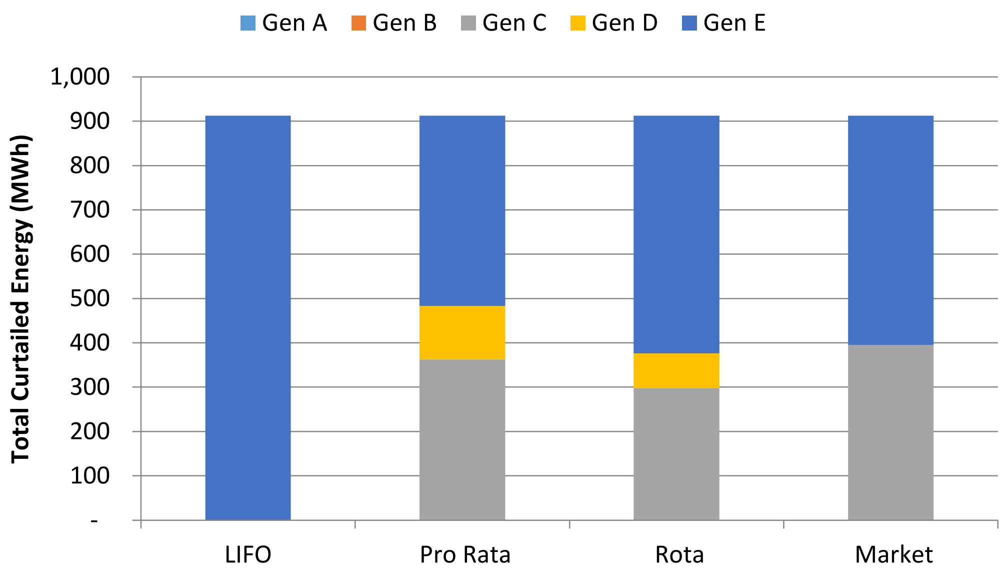

Figure 4-18 Study B: Total curtailed energy (MWh)

The capacity factors are presented in Figure 4-19. In general, the capacity factors are higher than in Study A however this is due to the lower volume of curtailment required in this study. The lowest capacity factor is 0.2 under a LIFO arrangement for Generator E. The other four generators do not experience any curtailment. Under a Pro Rata arrangement, Generators C, D and E have a capacity factor of 0.41 and for a Rota arrangement, the capacity factors range from 0.36 to 0.47. Generator A and B remain uncurtailed for the Pro Rata and Rota arrangements. The Market arrangements result in a minimum capacity factor of 0.37 for Generator E. Generator C is reduced to 0.39 while Generator D is uncurtailed.

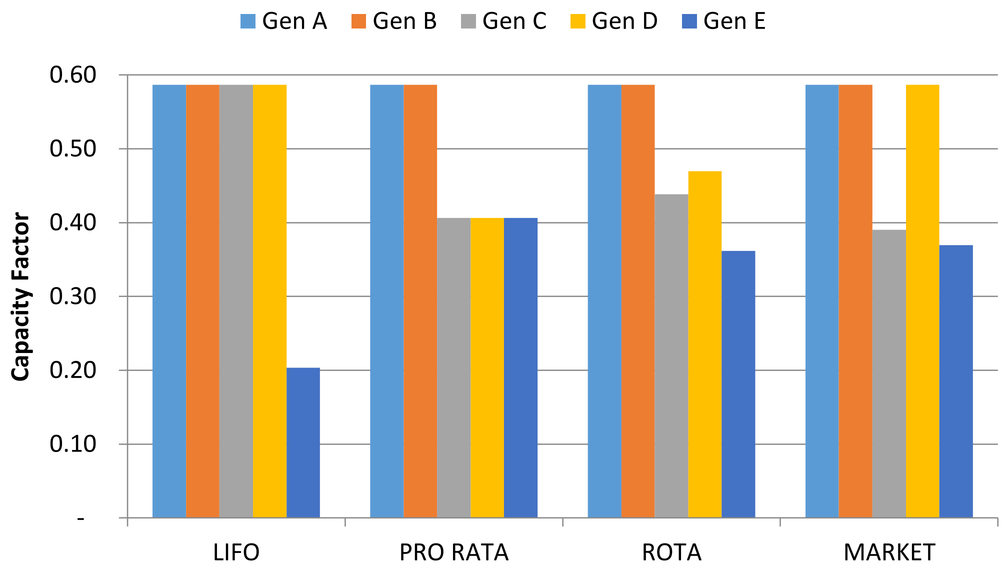

Figure 4-19 Study B Results: Impact of CF on non-firm wind generators in a six bus network with a local constraint

As in Study A, the Pro Rata and Rota arrangements demonstrate a more even balance of capacity factor amongst the three curtailed generators. The results of the Market arrangement differ from those in Study A. Generator B is no longer contributing to the constraint, and therefore Generators C and E are now the lowest cost generators which can be used to clear the constraint. Both generators have the same initial bid but this varies across the analysis period and the curtailment shared between both depending on which generator has the lowest bid as demonstrated in Figure 4-20.

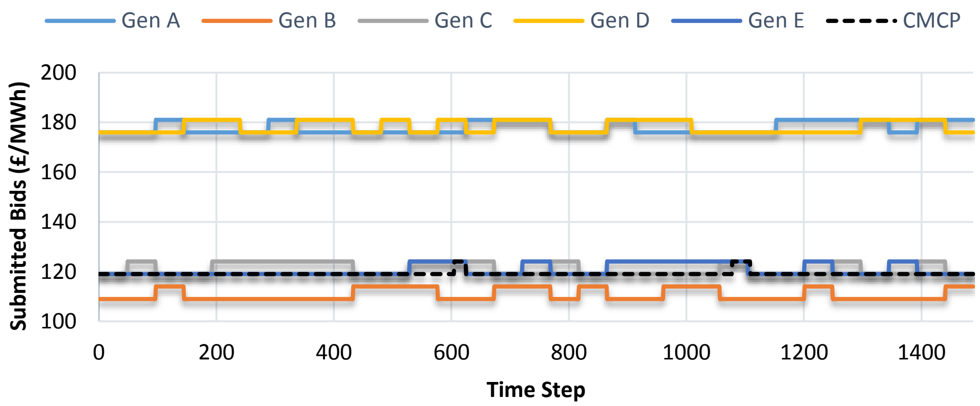

Figure 4-20 Study B: Dynamic bid behaviour

The total and average constraint costs are given in Figure 4-21 and Table 4-7. From Figure 4-21, it is evident that Generator E is the generator that receives the majority of compensation under all of the arrangements. Table 4-7 outlines the total and average costs of constraints for Study B. The Pro Rata arrangement results in the highest total and average cost of curtailment while the market arrangements give a similar cost to the LIFO arrangement. Due to the lower level of curtailment when compared with Study A, the costs and curtailment volumes are both lower. The majority of constraints can be cleared through the use of a single generator, Generator E. In the market examples, the costs are the same as Generator C and E have similar costs across the curtailment period, which translates into similar system prices across the analysis period.

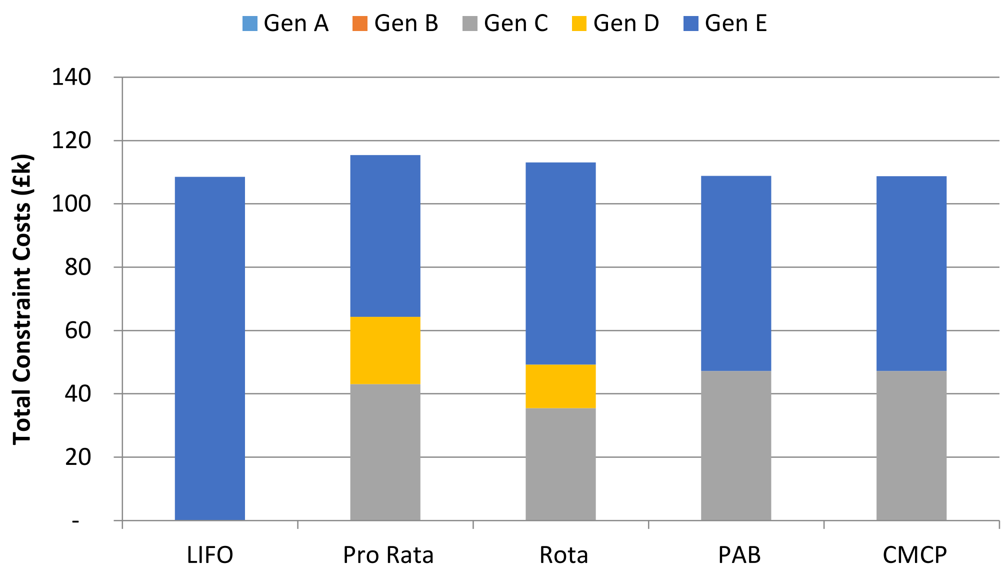

Figure 4-21 Study B: Total constraint payments for each PoA, showing the share between each generator

Table 4-7 Study B Results: Total and average constraint costs for each arrangement

	LIFO	Pro Rata	Rota	PAB	CMCP
Total Constraint Costs (£k)	109	115	113	109	109
Average Constraint Costs (£/MWh)	119	127	124	119	119

4.3.1.3 Study C: Distance to constraint

In a real network example, line losses will have an impact on network operation. To model this, each non-firm wind generator is placed behind a branch with a particular impedance. Those with a higher line impedance will experience higher losses and will therefore experience slightly more curtailment then would be necessary when connected to a line with zero impedance. The network topology and resistance characteristics are shown in Figure 4-22 below. The different coloured branches represent increasing levels of impedance where green is low, and red indicates high impedance.

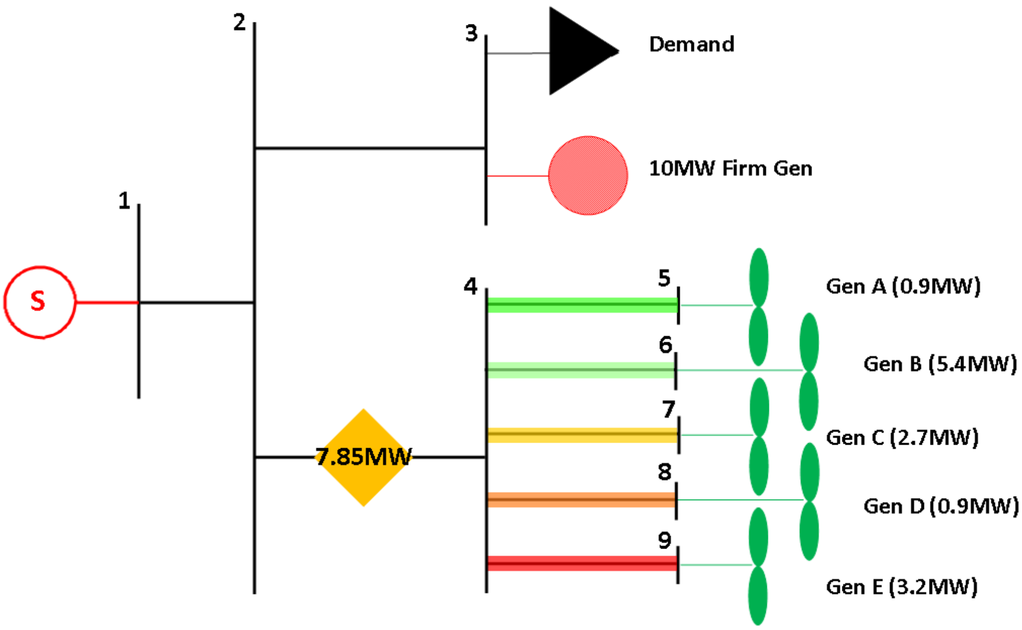

Figure 4-22 Study C network topology

During the Pro Rata PoA the following constraints are applied

$$Gen\ B = 6 \times Gen\ A \quad \text{(eq. 4.13)}$$

$$Gen\ C = 3 \times Gen\ A \quad \text{(eq. 4.14)}$$

$$Gen\ D = 1 \times Gen\ A \quad \text{(eq. 4.15)}$$

$$Gen\ E = 3.56 \times Gen\ A \quad \text{(eq. 4.16)}$$

These equations mean that when a constraint occurs, all generators will be curtailed by a percentage relative to their output at the time the curtailment is required. Generator A is behind the branch with the least impedance, and could therefore represent a generator that is adjacent to the constraint. Generator E has the highest line impedance and is therefore representative of a generator located furthest away from the constraint. As in Study A, all five generators are behind this single constraint. The limit of the line is set at 7.85 MW to give the same constraint volume in Study A and allow the results to be compared.

The total energy curtailed is shown in Figure 4-23. The results are relatively similar to those presented in Study A with the subtle difference occurring in terms of the total curtailed energy volume as a result of the resistance on the network branches.

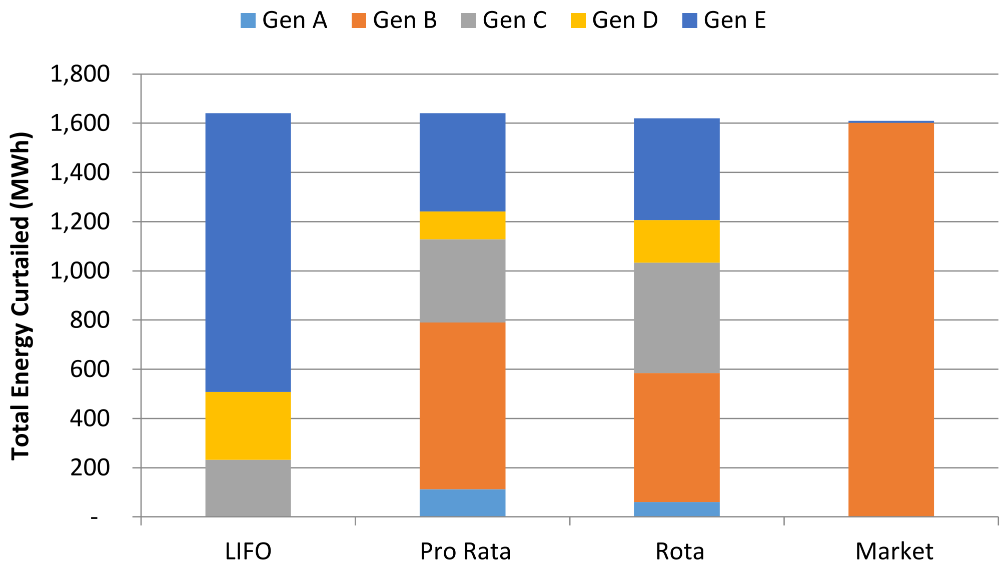

Figure 4-23 Study C: Total energy curtailed (MWh)

The monthly average capacity factors are shown in Figure 4-24 . The lowest capacity factor under a LIFO PoA is experience by Generator E and is 0.11, the same result as in Study A. The Pro Rata PoA gives a balanced capacity factor for all non-firm generators of 0.42. The Rota arrangement has a similar range of capacity factors when compared with those in Study A, of 0.33 to 0.50. There is only a slight change in the capacity factor of Generator B – this can be associated with changes to network losses. Similarly, for the market arrangements the results are comparable to Study A. Generator B has the lowest cost and is therefore curtailed the most. Generator E is curtailed on a very small number of occasions.

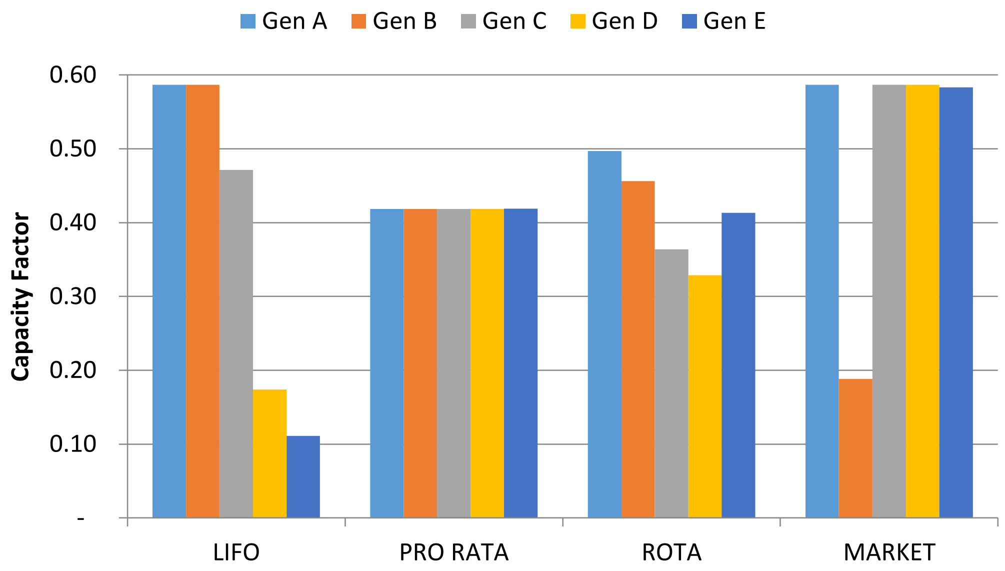

Figure 4-24 Study C Results: Impact of CF on non-firm wind generators in a six bus network with a local constraint

The market bid behaviour is shown in Figure 4-25. As with the other studies, Generators A, C and E form a group of lower bids while Generators B and D have a higher bid level. The total costs of curtailment are given in Figure 4-26 and Table 4-8. The market arrangements have lower total and average costs when compared with the non-market arrangements. As in Study A, Generator E is used to clear the majority of constraints under the LIFO arrangement which is a high cost generator. This results in a high overall cost for curtailment. The Pro Rata and Rota arrangements utilise other generators with lower costs and therefore the total cost of curtailment is lowered by a small amount.

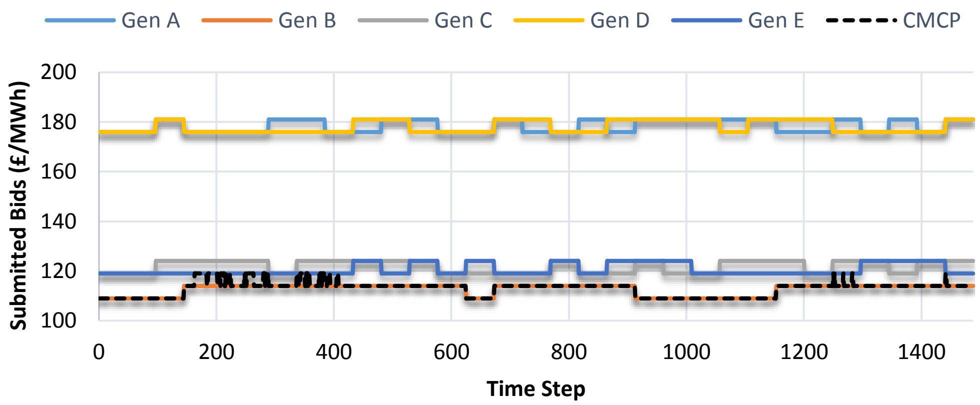

Figure 4-25 Study C: Dynamic bid behaviour

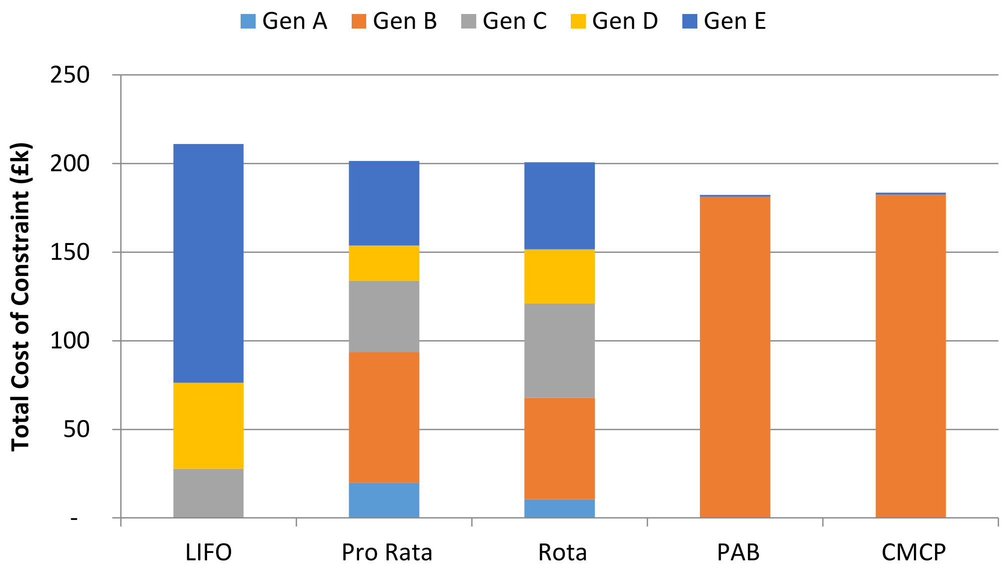

Figure 4-26 Study C: Total cost of curtailment (£k)

Table 4-8 Study C Results: Total and average curtailment costs for each PoA

	LIFO	Pro Rata	Rota	PAB	CMCP
Total Constraint Costs (£k)	210	201	203	182	182
Average Constraint Costs (£/MWh)	129	123	124	111	111

An important aspect of this study is the losses on the network. The choice of generator can have a significant impact on how electrically efficient the network is. If the price of the five generators is set to be equal, the OPF will consider only the losses on the network when determining which generator to curtail. This could be considered a 'technical best' solution. The results of a 'technical best' arrangement are shown below in Figure 4-27 and are compared with the results from the LIFO arrangement.

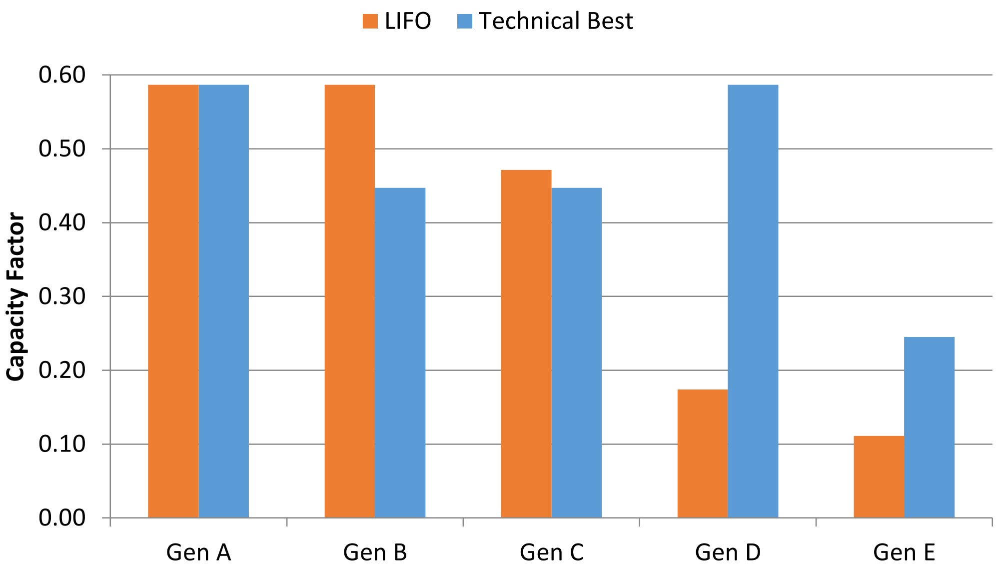

Figure 4-27 Study C Results: Capacity factor of non-firm generators under a 'technical best' arrangement compared with the LIFO capacity factors

The post curtailment network losses for all arrangements are shown below in Figure 4-28. The Rota and market scenarios result in the highest network losses. In the market scenario, Generator B is used to solve the constraint because it submits the lowest bid prices however it has a relatively low impedance when compared with Generator E for example, which will therefore result in higher losses i.e. the demand is being met by generators behind lines with a high impedance and therefore the losses on the network are increased. By comparison, in a LIFO or Technical best arrangement, Generator E that is behind the line with the highest impedance is curtailed the most.

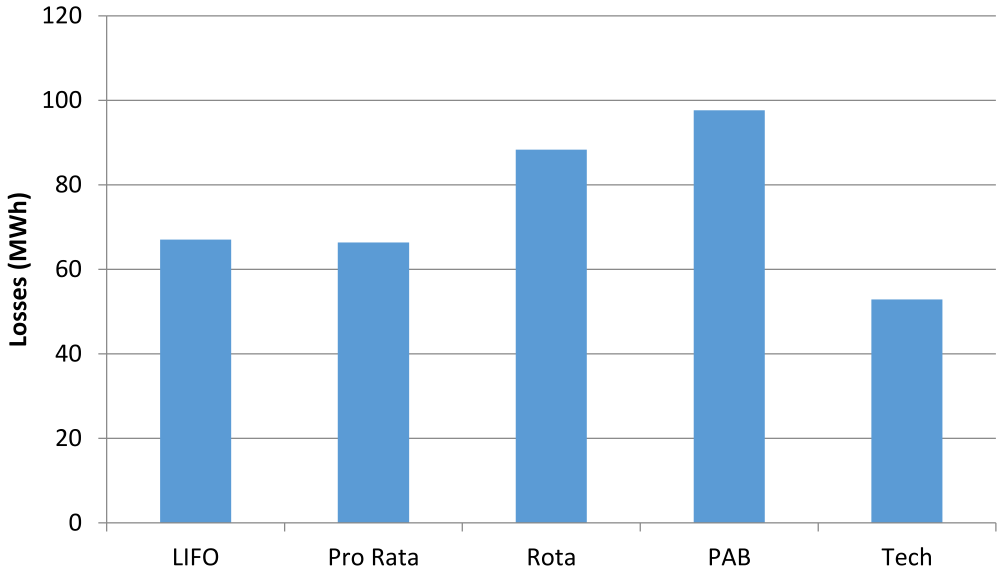

Figure 4-28 Study C Results: Network losses after PoA have been applied

The OPF solver chooses to curtail the generators who experience the highest losses while outputting energy to the network. This is combination of generator size and line resistance properties. As a result of these factors, Generators B, C and E are curtailed under a technical best arrangement. Generator E receives the highest percentage of curtailment although it should be noted that the minimum capacity factor of 0.24 is still higher than that which is experienced under LIFO when Generator E is last in the priority stack. In a LIFO arrangement, the cost overrides the network losses and the same generator will always be selected to clear a constraint. A technical best PoA allows the OPF to determine the best solution with regards to network losses, which often results in the selection of more than one generator to clear a constraint.

4.3.2 Comparison

The volumes of curtailed energy under a LIFO PoA for all three studies are shown in Table 4-9.

Table 4-9 Comparison of network values for a LIFO arrangement across the three studies.

	Demand (GWh)		Generation (GWh)		Slack Bus (GWh)		Losses		No of Const. Periods	Total Energy Curtailed (GWh)	Total Const. Payments (£k)	Avg. Const. Payment (£/MWh)
	Pre	Post	Pre	Post	Pre	Post	Pre	Post				
A	10.8	10.8	13.2	11.5	-2.3	-0.7	0	0	814	1.636	210	129
B	10.8	10.8	13.2	11.5	-2.3	-1.4	0	0	834	0.912	109	119
C	10.8	10.8	13.2	11.5	-2.2	-0.6	0.15	0.07	814	1.636	211	129

Study B differs from Study A in terms of total volume of curtailed energy. The thermal limit of the line is dropped down to 4 MW from 8 MW as there were only 3 generators behind the constraint with a total capacity of 6.8 MW. The number of constrained intervals was kept to a similar amount, but the total energy curtailed is 0.7GWh less than that demonstrated in Study A and C. This is also demonstrated by the 'average constraint payment' cost – there is only one generator required to clear the constraint and this has a lower £/MWh cost than the other four generators used in the study.

Studies A and B have no network losses associated with them as there were no impedances included in the branch properties. While this does not represent a real network example, excluding the network losses allows the OPF methodology to be verified on a simple model before more complex network models are studied.

In Study C, line impedances are included in the network model and it has a small impact on the volume of curtailed energy across the month. The line rating in Study C was set at 7.85 MW in order to match the volume of curtailed energy experienced under a LIFO arrangement in Study A.

Generator E is curtailed quite heavily across all scenarios, with the exception of the market scenario in Study A and Study C. In all three studies, the proportions of curtailment under a Rota arrangement are very similar to those of a Pro Rata arrangement. Both arrangements distribute the curtailment more evenly across all non-firm generators.

Generator B is the obvious choice for curtailment in the market arrangements; the low bid cost and high capacity mean that the network can rely on it to be the marginal generator in the majority of instances.

4.3.3 Model Validation

The results of the curtailment analysis using the OPF methods are compared to an excel spreadsheet calculation of capacity factors for the simple four bus example in Study A. The spreadsheet uses arithmetic and logic calculations to determine the volume of curtailment based on the three non-market curtailment approaches. For example, under a Pro Rata approached, the spreadsheet calculates the volume of curtailment required to clear the constraints, and then subtracts this from the connected generators based on their relevant contribution to the constraint.

The same demand and generation values are used as were input in to the OPF model, and when curtailment is required, it is allocated based on the selected PoA. The results are shown below in Table 4-10.

Table 4-10 Validation of modelling results – the capacity factors obtained using excel match those obtained using the OPF modelling methodology.

	LIFO		Pro Rata		Rota	
	Excel	OPF	Excel	OPF	Excel	OPF
A	0.59	0.59	0.42	0.42	0.50	0.50
B	0.59	0.59	0.42	0.42	0.45	0.45
C	0.47	0.47	0.42	0.42	0.36	0.36
D	0.18	0.18	0.42	0.42	0.33	0.33
E	0.11	0.11	0.42	0.42	0.41	0.41

The results of the excel analysis match those obtained for the OPF analysis. This demonstrates that the OPF method successfully applies various PoA to the network study and provides confidence in the OPF methodology for use on a real network case study.

While there can never be a completely accurate forecast of curtailment, DNOs often provide a conservative estimate based on historical demand and generation date. When issued with curtailment estimates, these values will be taken to lenders to secure funding for the development. Both generators and investors wish to have confidence in the estimates which is why validation of curtailment models is important to the industry, for both generators and investors alike.

4.4 Conclusion

This chapter has presented a methodology for quantitative assessment of the impact of selected PoA on non-firm wind generation in ANM schemes. The OPF methodology proposed uses generator cost functions to determine the order of curtailment of non-firm generators and the capacity factors are used as a metric for measuring the impact upon each generator. This methodology can be applied to both market and non-market arrangements, allowing them to be compared.

Three simple studies are provided to demonstrate some of the key characteristics of the PoA discussed in this thesis. Using different network topologies has allowed these characteristics to be compared thoroughly and a validation of the model using spreadsheet calculations grants confidence in the model for use in more complex network topologies.

The examples demonstrate that the LIFO arrangement results in relatively low capacity factors for the last generator connected to the network. Pro Rata and Rota arrangements provide a fairer, more balanced range of capacity factors across all of the non-market generators. The market arrangements demonstrate that costs of curtailment could be lowered if a market for curtailment were introduced. The costs noted for the non-firm arrangements are indicative of lost revenue to the generator and therefore an indication of the severity of the constraint. There is no compensation paid for non-market arrangement

The following chapter will apply this modelling methodology to a real network example. The branch and bus characteristics will create significant network losses which will be considered in the analysis of results however the key outcomes will be in line with those presented in this chapter.

5 Analysis of Principles of Access using a Case Study Network

5.1 Chapter Summary

In the previous chapter, the key results of different PoA were highlighted on a simple case study and a short sensitivity study carried out with the findings. This chapter will now expand upon those key results and explore any implications of applying the PoA on a real network case study. Using OPF modelling to compare PoA, the results can better quantify the impact different PoA have on the curtailment of wind. The key contribution made in this chapter is to demonstrate the impacts of a number of PoA in a real network case study and to discuss the implications of each PoA for not only the generator, but also the network operator.

The chapter begins by demonstrating the application of the OPF model to a real network case study and compares six different PoA: LIFO, Pro Rata, Rota, Pay-as-bid (PAB), Curtailment Market Clearing Price (CMCP) and Fixed Price. The comparison of each arrangement is based around the capacity factor of each wind farm pre and post curtailment. Costs of arrangements are also compared for the market arrangements, and indicative costs compared for non-market arrangements.

The chapter begins by outlining the key characteristics of the case study network – which is based in the most part on the Orkney distribution network. The chapter goes on to discuss the results of modelling non-market arrangements. The non-market arrangements are applied to the case study network with both local constraints and a single grid supply point (GSP) constraint. Sensitivity studies provide further examination of the impacts of generator size and generation mix on the curtailment of all non-firm generators connected to the network.

The chapter continues with a presentation and discussion of the results of the simulation that applies market PoA to the case study network with a single GSP constraint. In these examples, the costs of compensation payments are discussed and the bid behaviour of generators analysed. Sensitivity studies of the market arrangements explore the impact of changing subsidy levels, bid strategies, generator size, and game playing in the market which are all plausible variations to the base case.

The chapter will conclude with a comparison of all PoA – both market and non-market. The capacity factors and 'cost' of curtailment are compared and conclusions are made regarding the optimal choice of PoA for this case study, and other network types based on the results of this analysis.

Initial results from this case study have previously been published in IEEE Transactions on Power Systems. [165]

5.2 Case Study Network

The case study is based on the Orkney distribution network, located off the north coast of Scotland. This network has been operating an ANM scheme since 2009 and has a large volume of wind generation connected to the network. The network topology and connected generation is correct as of May 2012. Further details of the network are provided in this section, as are the generation and demand profiles used.

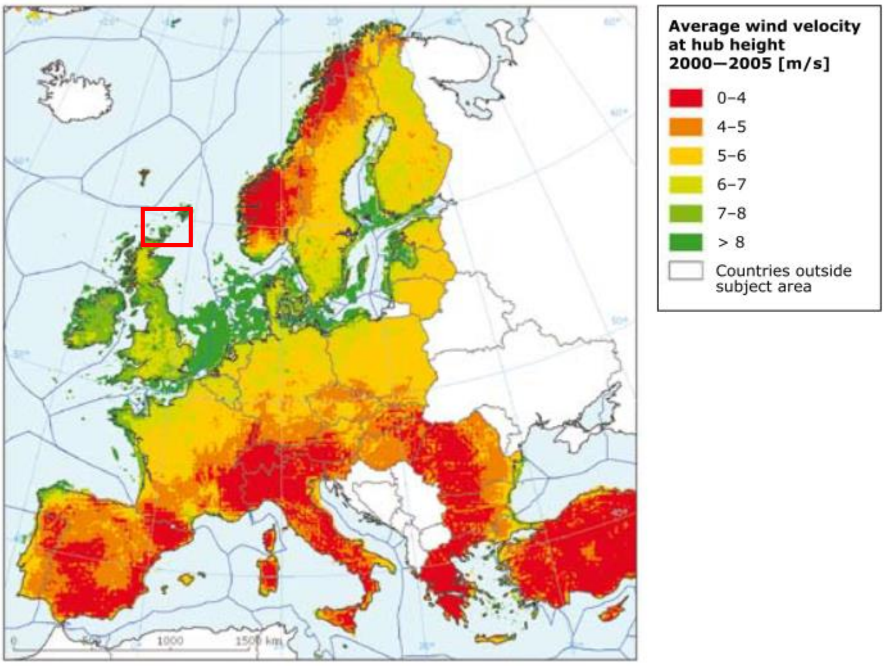

Figure 5-1 Wind resource map of Europe, showing that the UK has a high resource, and in particular the Orkney Islands (highlighted by the red box) off the north cost have a very high wind resource [166]

5.2.1 Case Study Network Characteristics

The network is composed of 67 buses, 25 generators, 71 branches, and 22 transformers. The circuit is 33kV with some 11kV feeders included in the model, which the majority of the demand and small wind generation is connected to. Details of all connected generation are given in Table 5-1. There are two conventional generators connected to the network, a gas plant and a diesel plant. The diesel plant is only used for back-up and emergency situations i.e. if the subsea cable connecting the distribution network to the main grid supply point fails. There is an exceptional renewable resource in Orkney, and this is reflected by the high volume of wind, wave and tidal generation connected to the network. While this case study is based on the Orkney distribution network, the results should not be used to draw conclusions regarding the current operation of the network. The aim of this study is to demonstrate the application of different PoA to a real network model. The connected wind generation details are correct as of May 2012 and the dates of connection determined using the UK Wind Energy Database [18]. There is a total of 42.05 MW of wind generation connected, of that 42.05 MW, 17.35 MW is non-firm. The generator details are listed in Table 5-1. Generator A was the first non-firm generation to connect, and Generator K the last to connect. The location of the generators is given in Figure 5-2. The installed capacity at the

Wave and Tidal sites is based on the available information from the European Marine Energy Centre website [167].

Table 5-1 Generation connected to case study network with capacity, energy source and connection type.

Gen ID	Connection Type	Type	Capacity (MW)	Priority Order
	Firm Generation (Including Wind and Marine Renewables)		35.7	
A	NON-FIRM	Wind	0.9	1
B	NON-FIRM	Wind	2.3	2
C	NON-FIRM	Wind	2.45	3
D	NON-FIRM	Wind	4.5	4
E	NON-FIRM	Wind	0.9	5
F	NON-FIRM	Wind	0.9	6
G	NON-FIRM	Wind	0.9	7
H	NON-FIRM	Wind	1.8	8
I	NON-FIRM	Wind	0.9	9
J	NON-FIRM	Wind	0.9	10
K	NON-FIRM	Wind	0.9	11

There are a number of known constraint locations, as detailed on the Scottish and Southern Energy ‘ANM Live’ website [79]. Each of these constraint locations forms the boundaries for the ‘constraint zones’. These are indicated by the dashed line in Figure 5-2.

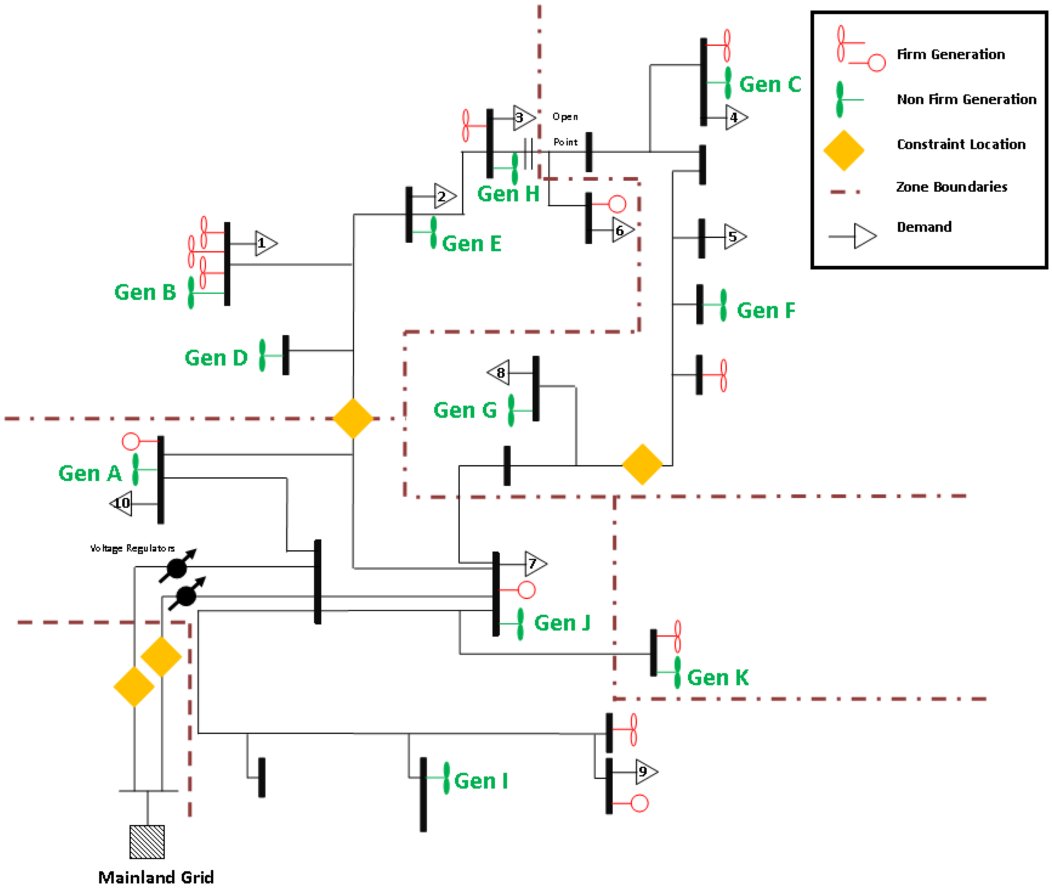

Figure 5-2 Diagram of case study network

5.2.2 Demand and Generation Profiles

Orkney has an exceptionally high wind resource, which results in a higher than average capacity factors for all wind generation connected to the network. The average annual capacity factor for the wind profiles used in this example is 0.51. For all demand and generation profiles, data for a full year (2009) in half hourly time steps are used. The profiles are shown in Figure 5-3. The same wind profile is used for all wind generators on the network, both firm and non-firm. For the wave generator, a four hour time-lag was applied to the wind profile. For the first four hours of the year, the last four hours of the wind profile was used. For the tidal generation and conventional generators additional profiles are used.

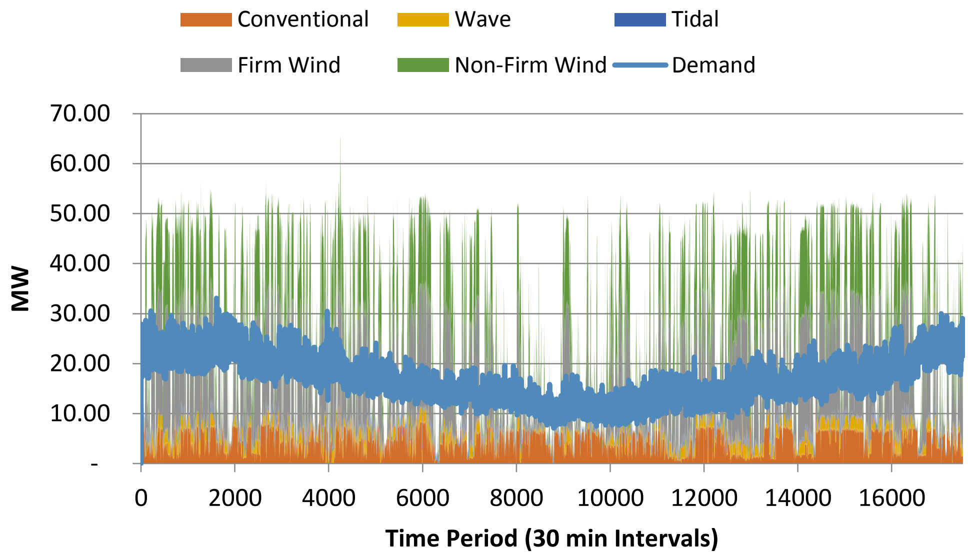

Figure 5-3 Power profiles applied to network case study model

It is evident from Figure 5-3 that the volume of both firm and non-firm wind exceeds island demand for a large proportion of the case study year. This is partly relieved by the 30MVA subsea cables which exports to the mainland GB grid supply point. The ANM scheme is used to manage the non-firm wind when it exceeds demand on the network.

The demand is distributed across the load points on the network using a percentage factor. This percentage is based on the population size of each island (and imports during periods of low wind). There are 10 load buses in total, as shown in Figure 5-2 and details of the percentage load share are given in Table 5-2. The largest demand bus is at ID 7 – the island 'mainland' where the majority of the Orkney population lives and works.

Table 5-2 Distribution of demand across network load buses.

Demand ID	Percentage Load Share
1	5.61%
2	1.4%
3	2.8%
4	3.27%
5	1.4%
6	0.94%
7	65.42%
8	1.4%
9	0.47%
10	17.3%

5.2.3 OPF Constraint Formulation based on specific Case Study issues

In order to apply Pro Rata arrangements accurately, additional constraint equations are required in the OPF formulation. There will be two constraint scenarios used in the case study. The first will look at the impact of local constraints on the curtailment of generation, when there is only a proportion of the total non-firm generation behind the constraint. Secondly, a single constraint is applied, and all 11 non-firm generators are behind this constraint i.e. all generators are contributing towards this constraint.

5.2.3.1 Additional Equations for Local Constraint Example

Constraints on a network give a signal of particular areas which require constraint management or traditional reinforcements. By looking at local constraints, an indication of the importance of generator location and severity of the constraint can be obtained by comparing the curtailment of those behind the constraint with those generators in other areas of the network which are not subjected to the same constraints.

For this case study, there are two local constraints on the network. These are shown in Figure 5-4. When a constraint occurs in one or both of these locations, the generators contributing to the constraint are curtailed.

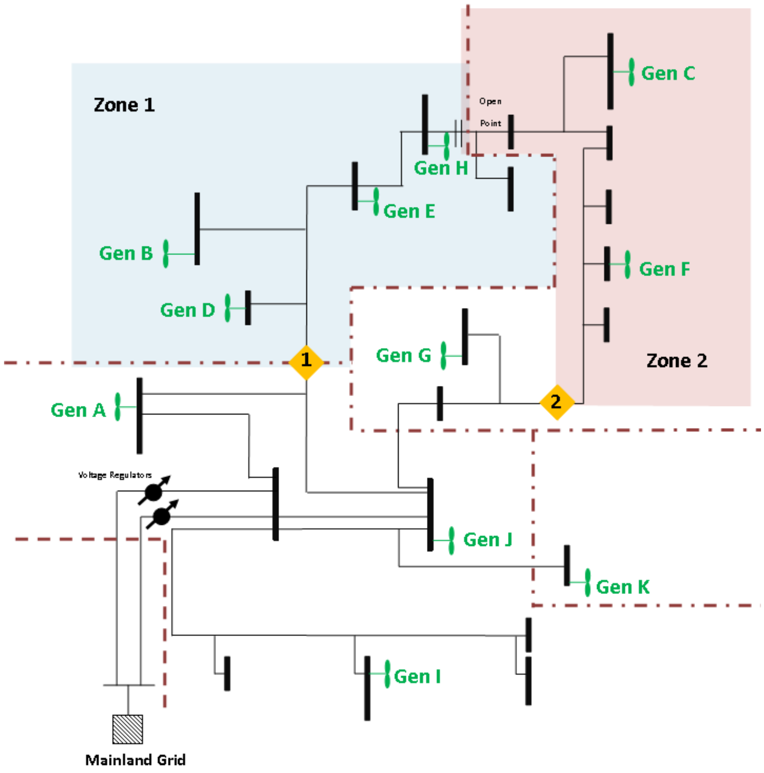

Figure 5-4 Location of local constraints and Pro Rata curtailment zones.

As explained in Chapter Four, the constraint equations are used to ensure that under the Pro Rata PoA, curtailment is applied based on the proportionate share of the generator output to the total output of all generators. The Pro Rata curtailment is applied within each zone. For example, when there is a constraint occurrence at Constraint 1, then only Generators B, D, E and H will be curtailed. Generator E is issued an instruction to reduce their output to 0.5 MW. Generator B would therefore have an output of 1.25 MW, Generator D would have an output of 2.5 MW and Generator H would have output of 1 MW. A similar format applied to Constraint 2. Based on these local constraint locations, the constraint equations are as follows:

Zone 1

$$GenB_{output} = 2.56 \times GenE_{output} \quad \text{(eq. 5.1)}$$

$$GenD_{output} = 5 \times GenE_{output} \quad \text{(eq. 5.2)}$$

$$GenH_{output} = 2 \times GenE_{output} \quad \text{(eq. 5.3)}$$

Zone 2

$$GenC_{output} = 2.72 \times GenF_{output} \qquad \text{(eq. 5.4)}$$

5.2.3.2 Additional Equations for Single Constraint Example

This case study will look at a single constraint at the GSP. A diagram showing the location of the constraint is shown in Figure 5-5. The blue shaded area covers all the generators on the network, as they are all contributing to the constraint. This example will provide a case where all generators are subjected to the same constraint and give an overview of the impact of different PoA on a relatively large number of generators. This large group allows a wider range of sensitivity studies to be carried out and further conclusions to be made regarding alternative PoA to the LIFO arrangement.

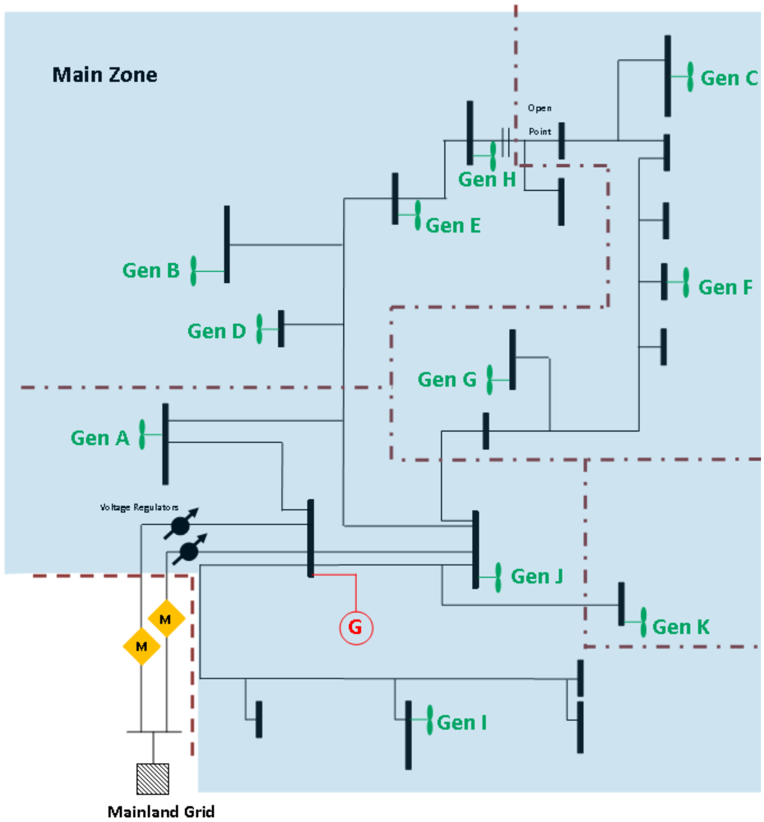

Figure 5-5 Figure to demonstrate the impact of a single constraint on the network.

In order to create a single constraint on the network, changes were made to the network model. Firstly, the thermal ratings of the branches where the local constraints exist were increased in order to remove these constraints. Secondly, to create a new constraint, 14 MW of firm, always-on generation was added to the core of the network, indicated by the Generator symbol in Figure 5-5. 14 MW was the maximum amount of generation that could be added to the network without the need to curtail any firm generation. The aim of adding this additional generation is to make the network more constrained than might typically be expected, and model the impact.

As all generators are now behind a single constraint at the GSP, the constraint equations will change to reflect this i.e. all generators contribute to the same constraint. All generators will be curtailed based on output at the time of constraint. For example, Generator A is instructed to reduce output to 0.5 MW, Generators E, F, G, I ,J, K who are the same capacity as Generator A are also reduced to 0.5 MW. Generator H is reduced to 1 MW, Generator B, C, D are reduced to 1.28 MW, 1.36 MW and 2.5 MW respectively. The constraint equations are as follows:

$$GenB_{output} = 2.56 \times GenA_{output} \quad \text{(eq. 5.5)}$$

$$GenC_{output} = 2.72 \times GenA_{output} \quad \text{(eq. 5.6)}$$

$$GenD_{output} = 5 \times GenA_{output} \quad \text{(eq. 5.7)}$$

$$GenE_{output} = 1 \times GenA_{output} \quad \text{(eq. 5 .8)}$$

$$GenF_{output} = 1 \times GenA_{output} \quad \text{(eq. 5.9)}$$

$$GenG_{output} = 1 \times GenA_{output} \quad \text{(eq. 5.10)}$$

$$GenH_{output} = 2 \times GenA_{output} \quad \text{(eq. 5.11)}$$

$$GenI_{output} = 1 \times GenA_{output} \quad \text{(eq. 5.12)}$$

$$GenJ_{output} = 1 \times GenA_{output} \quad \text{(eq. 5.13)}$$

$$GenK_{output} = 1 \times GenA_{output} \quad \text{(eq. 5.14)}$$

5.2.4 Pre-curtailment Costs

The pre-curtailment costs shown in Table 5-3

Table 5-3 are used as the starting point for the market bid scenarios, and also to provide indicative costs of curtailment for the non-market arrangements which will later be used for comparative purposes. These costs provide an idea of the potential lost revenue non-firm generators may be subjected to under different curtailment arrangements. These prices have been calculated following the methodology outlined in Chapter Four.

Table 5-3 Precurtailment revenue values for case study non-firm generation

Gen ID	Support Scheme	Electricity (£/MWh)	FIT tariff (£/MWh)	LECs (£/MWh)	Embedded benefits (£/MWh)	Lost Revenue (£/MWh)
A	FIT	58.50	107.2	4.87	5.50	**176**
B	FIT	58.50	50.5	4.87	5.50	**119**
C	FIT	58.50	50.5	4.87	5.50	**119**
D	FIT	58.50	50.5	4.87	5.50	**119**
E	FIT	58.50	107.2	4.87	5.50	**176**
F	FIT	58.50	107.2	4.87	5.50	**176**
G	FIT	58.50	107.2	4.87	5.50	**176**
H	FIT	58.50	50.5	4.87	5.50	**119**
I	FIT	58.50	107.2	4.87	5.50	**176**
J	FIT	58.50	107.2	4.87	5.50	**176**
K	FIT	58.50	107.2	4.87	5.50	**176**

5.3 Non-Market PoA Modelling

The non-market models look at the impact of LIFO, Pro Rata and Rota PoA on a network with local constraints and a network with a single GSP constraint. Both these scenarios are presented in this subsection, and some further sensitivity studies presented. Indicative curtailment costs are based on the 'pre-curtailment profit' levels used to initiate the market modelling scenarios. These costs give an indication of the 'value' of the curtailment and can be used to compare the non-market results to the market arrangements later on in this chapter.

5.3.1 Non-Market PoA Study of Local Constraints

This study is based on the network configuration discussed in Section 5.2.3.1 and refers to Constraint 1 and Constraint 2 as presented in Figure 5-4.

5.3.1.1 *Number of Congested Periods in the Local Constraint Study*

The number of congested periods is shown in Figure 5-6 below. Each count of congestion represents a 30-minute time step. In real network operation, most constraint cases would be cleared within a matter of minutes and the generator returned to pre-curtailment output levels when network conditions permit. There is a total of 6,634 constrained periods which accounts for 37.8% of the year or 3,317 hours.

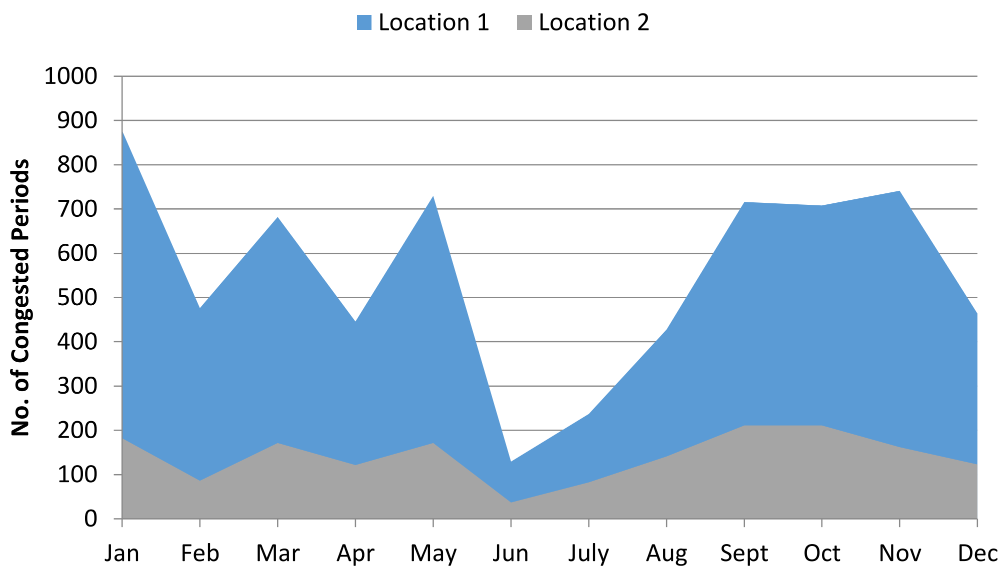

Figure 5-6 Number of congested periods when local constraints are active on the case study network.

The majority of constraints occur at Constraint 1 to the west of the network. This will lead to generators B, D, E and H experiencing the most curtailment. Generator C and F will experience a small volume of curtailment across the year due to Constraint 2, but significantly less than generators who are behind Constraint 1.

5.3.1.2 Total Curtailment in Local Constraint Study

A comparison of curtailment across the three non-firm market arrangements is shown in Figure 5-7. The total curtailment volume is 15GWh, which equates to 6% of the uncurtailed volume, and 13% of the net demand/generation volume. Generators B, D, E and H contribute towards Constraint 1 and Generators C and F contribute towards Constraint 2.

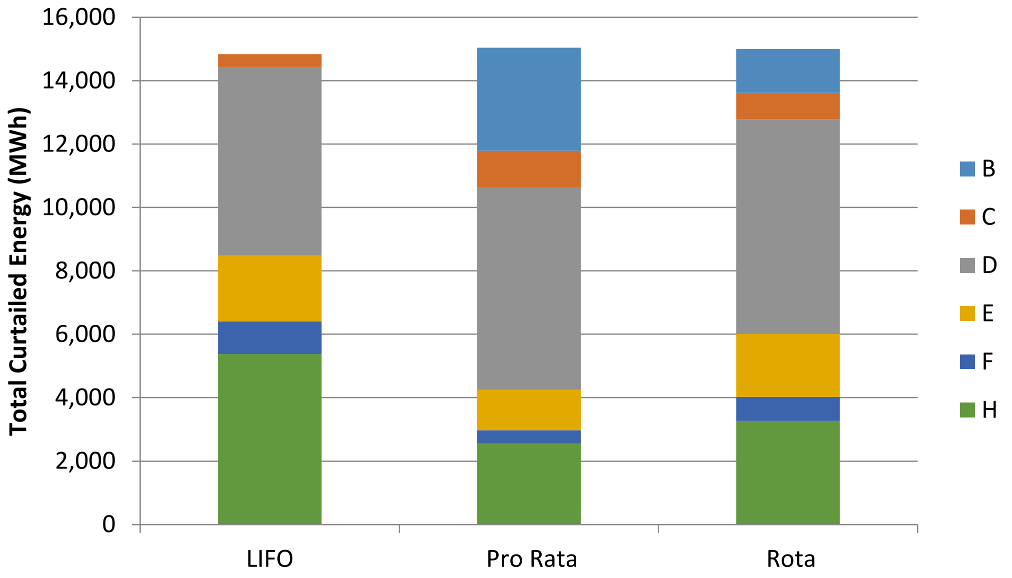

Figure 5-7 Total Curtailment for each of the non-market arrangements behind local constraints

The average annual capacity factors are shown in Figure 5-8. This figure demonstrates the impact of the local constraints on particular generators behind the local constraints. As indicated in Figure 5-6, there are significantly more constraint occurrences at Constraint 1 and therefore the curtailment of Generators B, D, E and H is higher than that of Generators C and F. The total curtailment in Figure 5-7 and capacity factors are presented in Figure 5-8. Under a LIFO arrangement, the lowest priority generator, Generator H, experiences a high volume of curtailment across the year dropping the annual capacity factor from 0.51 down to 0.17. Generators D and E experience moderate curtailment with capacity factors being reduced to 0.36 and 0.25 respectively. Generator B remains uncurtailed. Generator H is the only generator to experience curtailment well below the UK national average of 0.26 [168]. For Generators C and F behind Constraint 2, they experience less curtailment compared to those generators behind Constraint 1, only dropping to 0.49 and 0.38 respectively.

The Pro Rata arrangement gives an annual capacity factor of 0.35 for the four generators behind Constraint 1, and 0.46 behind Constraint 2. The capacity factor behind Constraint 2 is higher because the occurrence of this constraint is less when compared with Constraint 1. The capacity factor behind both constraints would decrease should the number of generators increase in the future.

Under a Rota arrangement, the capacity factors range from 0.47 to 0.26. While Generator E is the most curtailed generator under this arrangement, the capacity factor is equal to the national average.

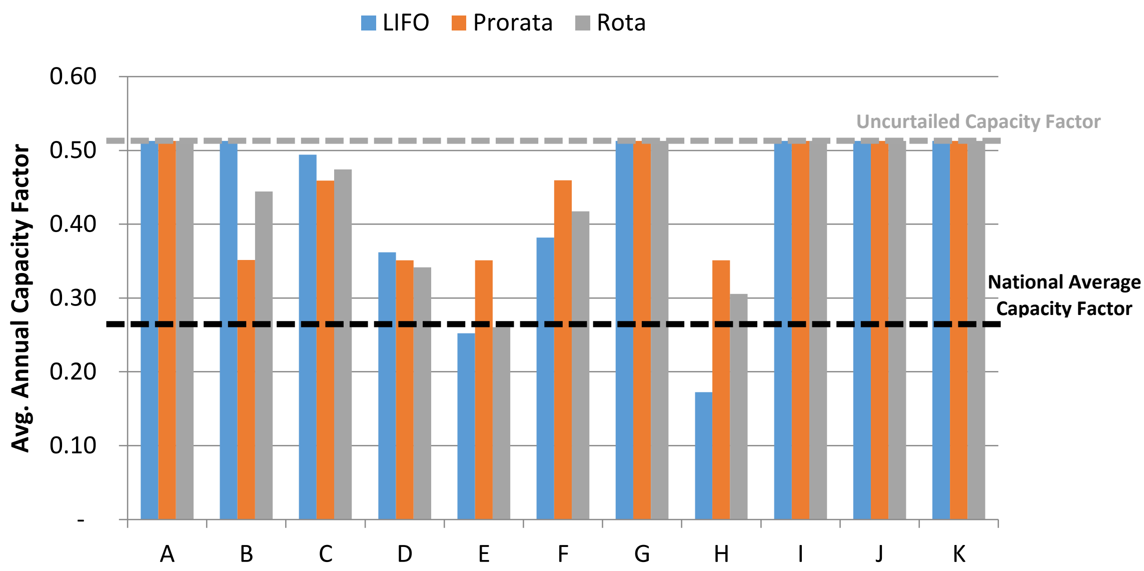

Figure 5-8 Average Annual Capacity Factor for generators on a network with local constraints

Overall, generators who are at the bottom of the priority stack i.e. generators H and E fair significantly better under Pro Rata and Rota arrangements when compared with LIFO. Generator D has similar results under all three arrangements. The position of Generator D in the LIFO stack is such that the majority of the constraint is cleared before Generator D is called upon and therefore only experiences a fraction of curtailment experienced by Generators H and E under a LIFO arrangement. Generator B experiences a greater drop in capacity factor when the arrangement moves away from LIFO due to its top position in the priority stack. Generator B will suffer regardless of which other PoA is applied when compared with LIFO, as it has a high priority under LIFO.

5.3.1.3 Cost of Curtailment in Local Constraint Study

The total and average constraint costs are shown in Table 5-4 and are calculated using the pre-curtailment costs given in Table 5-3. These costs do not represent compensation paid to generators; they are intended to give an estimated value of lost revenue experienced by each non-firm generator when subjected to curtailment. The allocation of curtailment costs to each non-firm generator is given in Figure 5-9.

Table 5-4 Summary table of total and average constraint costs for non-firm arrangements

	LIFO	Pro Rata	Rota
Total Constraint Costs (£k)	1,943	1,887	1,942
Average Constraint Costs (£/MWh)	131	125	129

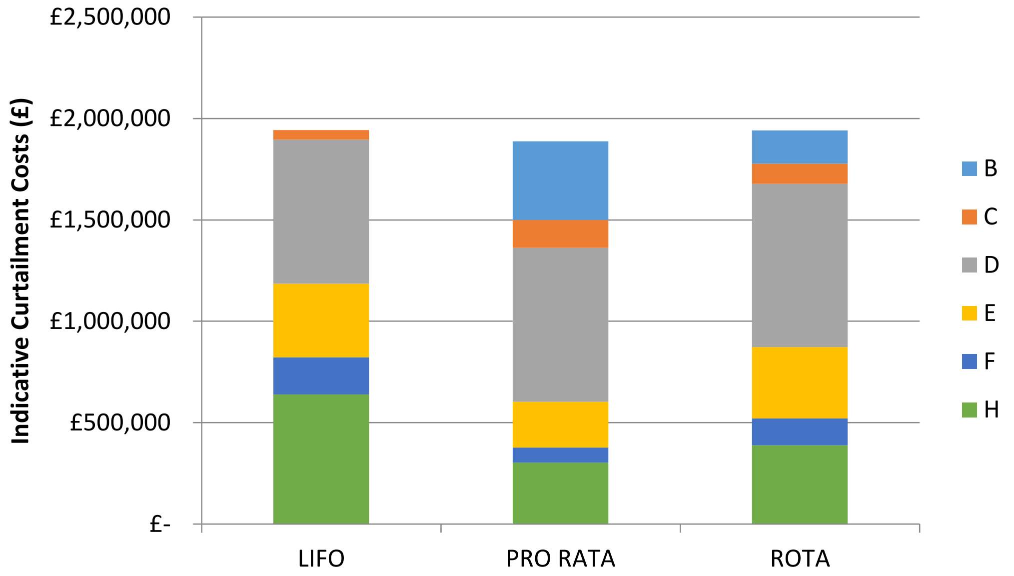

Figure 5-9 Indicative costs of non-market arrangements

Total constraint costs do not vary drastically across the three arrangements. This can be explained by the calculation of pre-curtailment costs – the majority of the generators behind the local constraints have similar pre-curtailment costs and therefore similar compensation levels under this fixed price model. Only Generators E and F have a higher cost. The Pro Rata arrangement has the largest volume of total curtailed energy (See Figure 5-7), however the most expensive generator, Generator E is used less in this arrangement when compared with LIFO and Rota arrangements, and therefore the total curtailment costs are reduced. The Pro Rata arrangement has the lowest total and average constraint costs out of the three non-firm arrangements. The LIFO and Rota arrangements result in higher curtailment costs because of the higher curtailment of Generator E when compared with the Pro Rata arrangement. Generator E receives a higher subsidy level than Generators B, D and H because it is a smaller turbine. This will result in higher curtailment costs for the generation curtailment overall, based on the cost methodology used in this work. The next study will consider non-market PoA on a network with a single GSP constraint.

5.3.2 Non-Market PoA Study of a GSP Constraint

This study is based on the network configuration outlined in Section 5.2.3.2. There is a single constraint located at the GSP and all non-firm generators will contributed to this single constraint, as shown in the diagram in Figure 5-5.

5.3.2.1 *Number of Congested Periods in GSP Constraint Study*

The number of congested periods is shown in Figure 5-10 below. There is a total of 3,332 constrained periods which accounts for 19% of the year or 1,666 hours. The months with the highest curtailment are May, September and November due to high wind output of all generating units as the same wind profile is assumed for all generators on the system.

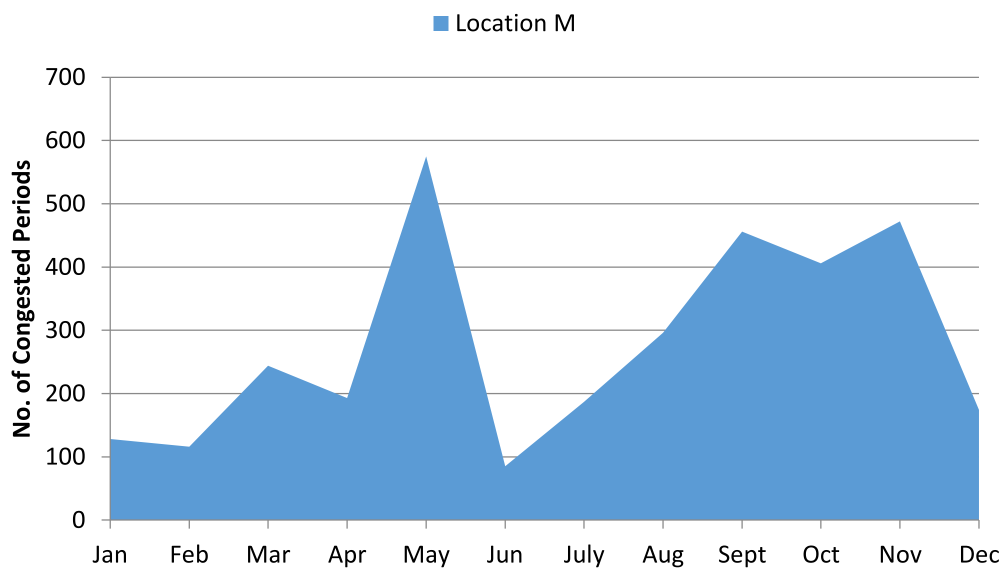

Figure 5-10 Number of constrained periods occurring during one year on the case study network. Each constraint period represents a 30 minute time step

5.3.2.2 *Total Curtailment in GSP Constraint Study*

A comparison of curtailment across the three non-firm market arrangements is given in Figure 5-11. All 11 non-firm generators are curtailed at one of more periods during the year, and the total curtailment shown in Figure 5-11.The total curtailed volume ranges from 9.4GWh to 10.7GWh depending on the arrangement. This accounts for around 2.5% of the uncurtailed output and 4% of net demand/generation.

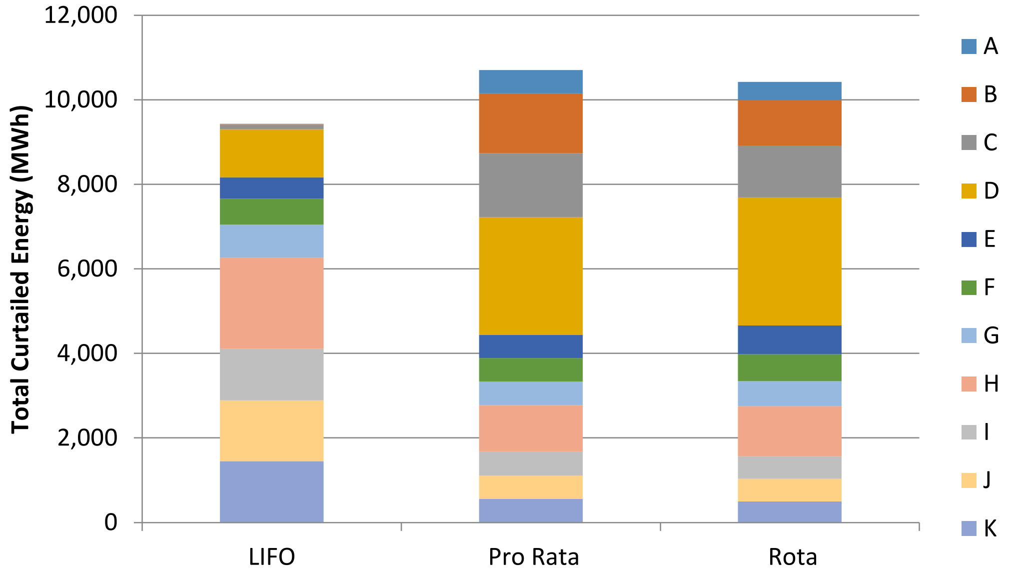

Figure 5-11 Total curtailment for each of the non-market arrangements behind a single GSP constraint

The difference in total curtailment volume is due to network losses. The losses under each arrangement are shown in Figure 5-12. The LIFO arrangement experiences the highest network losses overall because the generators that are curtailed for the majority of the time (Generators I, J and K) are situated relatively close to the constraint location. Therefore, other generators which are further away from the constraint continue to generate and create higher losses. The losses equate to 6% of energy generated across the year. This high loss percentage is likely the result of having to operate the network at a level beyond which it was first designed for.

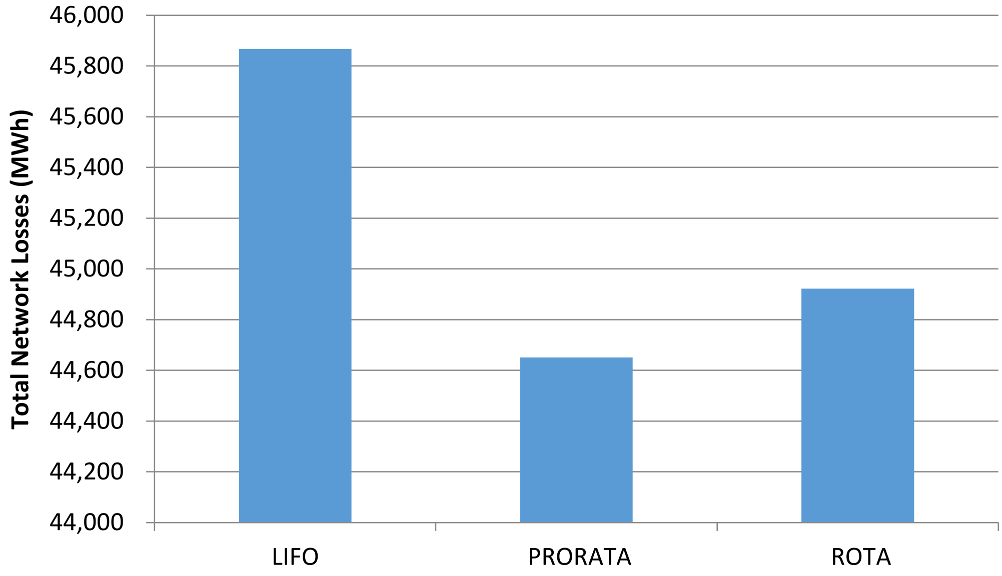

Figure 5-12 Diagram of losses on a network with a single constraint at GSP under different arrangements

The average annual capacity factors are shown in Figure 5-13. In contrast to the results presented in the previous section (see Figure 5-8), all generators are now subjected to curtailment. It should also be highlighted, that there are around 50% less curtailed periods for this example and therefore figures should not be directly compared to the local constraint example.

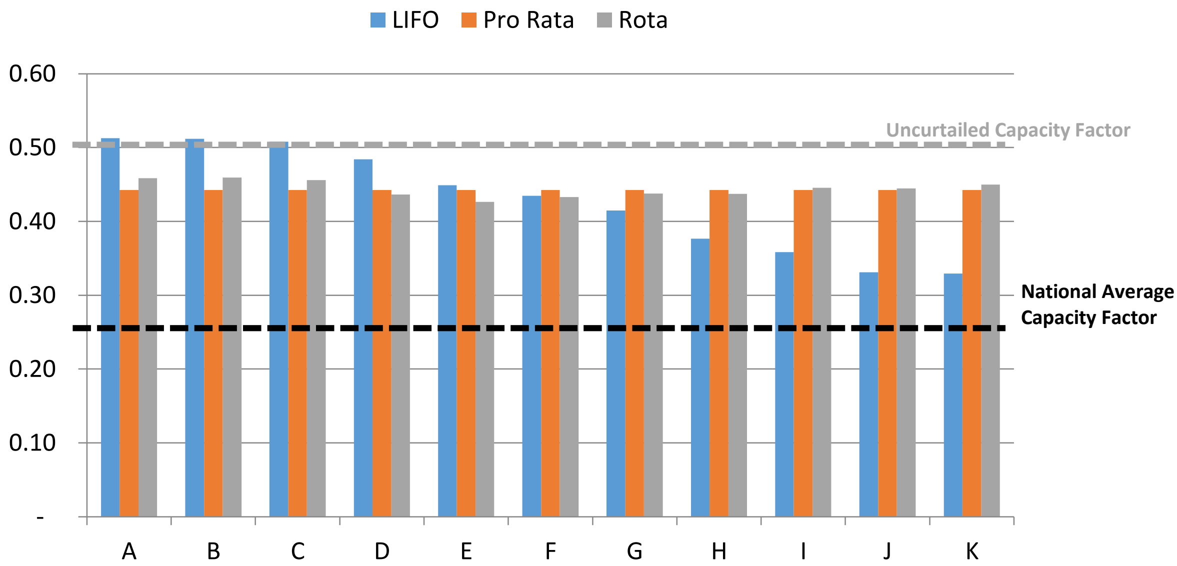

Figure 5-13 Average annual capacity factor for generators on a network with a single GSP constraint

Under a LIFO arrangement, Generators J and K, located at the bottom of the priority stack have their capacity factor reduced down to 0.33 from an uncurtailed capacity factor of 0.51. Generators A, B and C remain uncurtailed.

The capacity factor experienced under Pro Rata and Rota arrangements are similar. For the Pro Rata arrangement, all Generators experience a capacity factor of 0.44 and for a Rota arrangement the capacity factor ranges from 0.46 to 0.43. While initially it appears that Pro Rata and Rota arrangements are undesirable given that they result in a larger total volume of curtailment, the individual impact on each generator is not as high as the LIFO arrangement because the curtailed energy is more evenly distributed between all non-firm generators. This result raises the issue that what is best for individual generators, is not necessarily the optimal solution for the network overall. The network operator is incentivised to minimise network losses. However, they must still attract connections from renewable generators by providing an economically viable capacity factor for non-firm generation.

5.3.2.3 Cost of Curtailment in GSP Constraint Study

The total and average constraint costs are show in Table 5-5. The indicative costs associated with this example are shown in Figure 5-14. Pro Rata and Rota have similar average constraint costs due to the distribution of total curtailment across all generators under each arrangement. Pro Rata has a higher total cost, but the total energy curtailed is also slightly higher.

Table 5-5 Summary of total and average constraint costs for non-firm arrangements on a network with a single GSP constraint

	LIFO	Pro Rata	Rota
Total Constraint Costs (£k)	1,465	1,496	1,463
Average Constraint Costs (£/MWh)	155	140	140

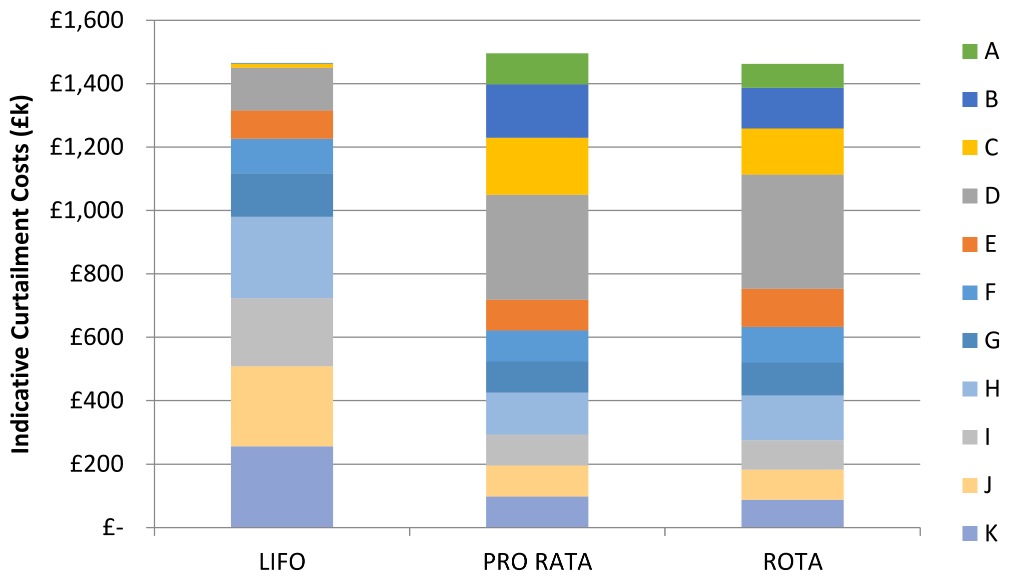

Figure 5-14 Indicative costs of non-market arrangements on a network with a single GSP constraint

Total costs are similar under all arrangements, with the LIFO arrangement having the higher average cost. This is due to the curtailment of multiple small, high cost generators who are located at the bottom of the priority stack i.e. Generators I, J and K.

Overall, the GSP constraint results have demonstrated the change non-firm generators can expect under different PoA and in particular, the contrast between LIFO and the other two non-firm arrangements. Those generators who are at the bottom of the priority stack would prefer an alternative to LIFO, while those with a high priority stack position would strongly oppose a move away from a LIFO arrangement.

5.3.3 Sensitivity Studies of Non-Market PoA

In order to appreciate the impact of a number of different factors on the operation of the OPF model and the resulting generator capacity factors, some sensitivity studies were carried out. These studies look at three different impacts in order to provide a broad view of potential curtailment behaviours. The first study will reverse the curtailment order of the LIFO priority stack. The second study considers a 'technical best' approach and finally, a third study looks at the impact of changing the number and capacity of generators.

5.3.3.1 Non-Market Sensitivity Study #1: Reversing the LIFO order

The base case LIFO stack has smaller generators at the bottom of the stack and larger generators at the top. By reversing this order, i.e. Generator A is now at the bottom of the priority stack and will be the first to curtail and Generator K is now at the top of the priority stack and is last to curtail, the impact on the overall curtailment and individual capacity factor is shown in Figure 5-15 and Figure 5-16.

There is a higher volume of overall curtailment for the reversed order. The generators that are subjected to the most curtailment i.e. Generators A, B and C, are located further from the constraint when compared with the original LIFO example when Generators I, J and K were the most curtailed.

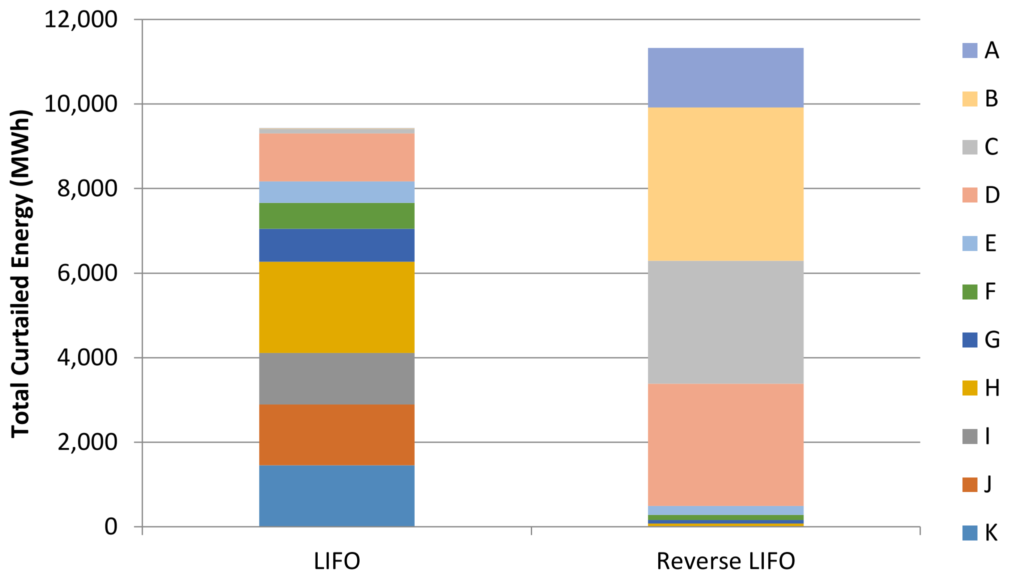

Figure 5-15 Total curtailed energy for LIFO and the reverse LIFO case

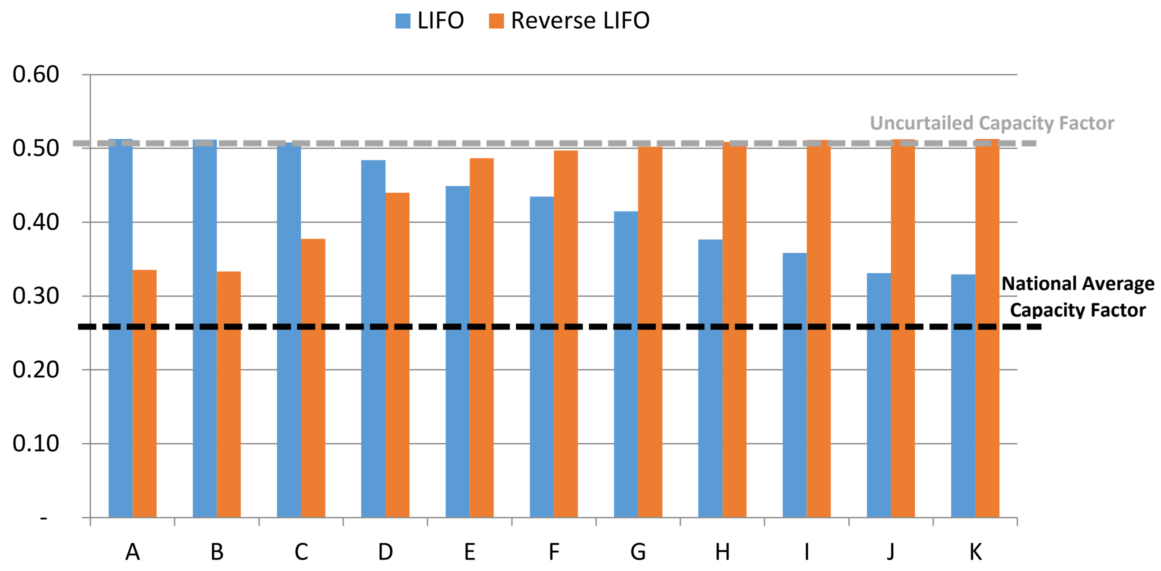

Figure 5-16 The average annual capacity factors for a LIFO arrangement, and a second LIFO arrangement where the curtailment order has been reversed

In terms of average annual capacity factor, in the 'reverse LIFO' case there are fewer generators affected by curtailment. Generators B, C and D are 2.3 MW, 2.45 MW and 4.5 MW. This is 2-5 times greater than Generators I, J and K which are curtailed first under the original LIFO curtailment order. In the reversed LIFO case, Generators H, I, J and K remain uncurtailed. In both cases, the minimum capacity factor is 0.33.

This study has demonstrated the impact of having large or small generators at each end of the priority stack. When larger generators are curtailed first, there is less of an impact on the rest of the stack. When there are smaller generators curtailed first, the curtailment is distributed further up the priority stack and more generators are affected by curtailment.

5.3.3.2 Non-Market Sensitivity Study #2: Technical Best

This study allows the OPF solver to choose the best generator to curtail by setting all non-firm generators to have the same OPF cost i.e. of equal priority. Similar to the results demonstrated by the simple example in Chapter Four, the OPF curtails the generators which create the most losses on the system i.e. the objective function of the OPF is to provide a solution with the lowest volume of losses on the network. The losses are compared in Figure 5-17 and the capacity factors compared in Figure 5-18.

The definition of technical best in this case refers the minimisation of losses on the network. However, in other cases the priority may be to minimise the curtailment of generators (certainly this would be the preference of the generators).

In terms of losses, the results are as expected; the losses are reduced by 2GWh across the year. Generators located furthest away from the constraint are curtailed more than those located nearer to the constraint. In particular, the larger generators, B, C and D experience the most curtailment. These generators are located far from the constraint and have the capacity available to clear the constraints.

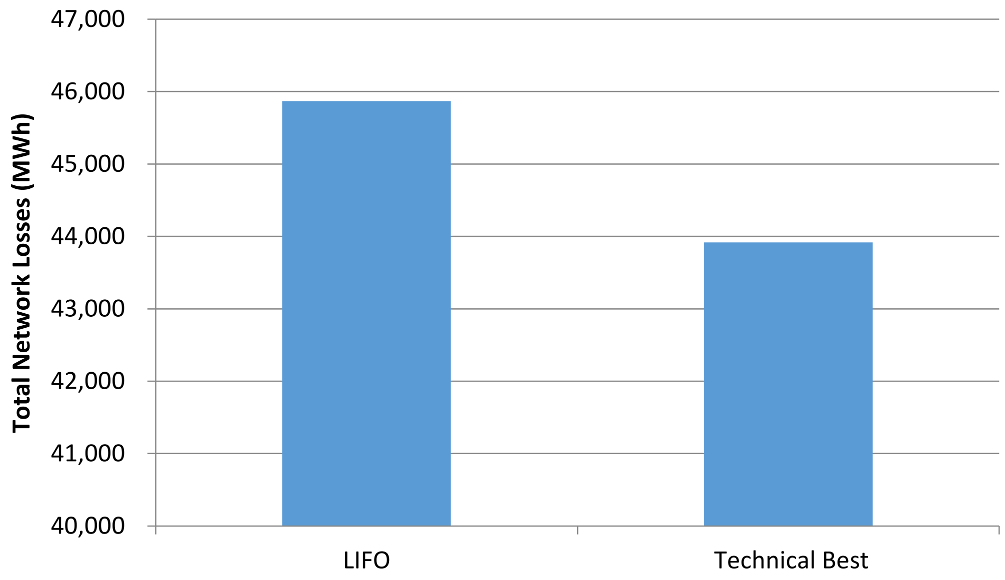

Figure 5-17 Comparison of the losses experience on the network under a LIFO arrangement and a 'Technical Best' arrangement which is designed to minimise losses

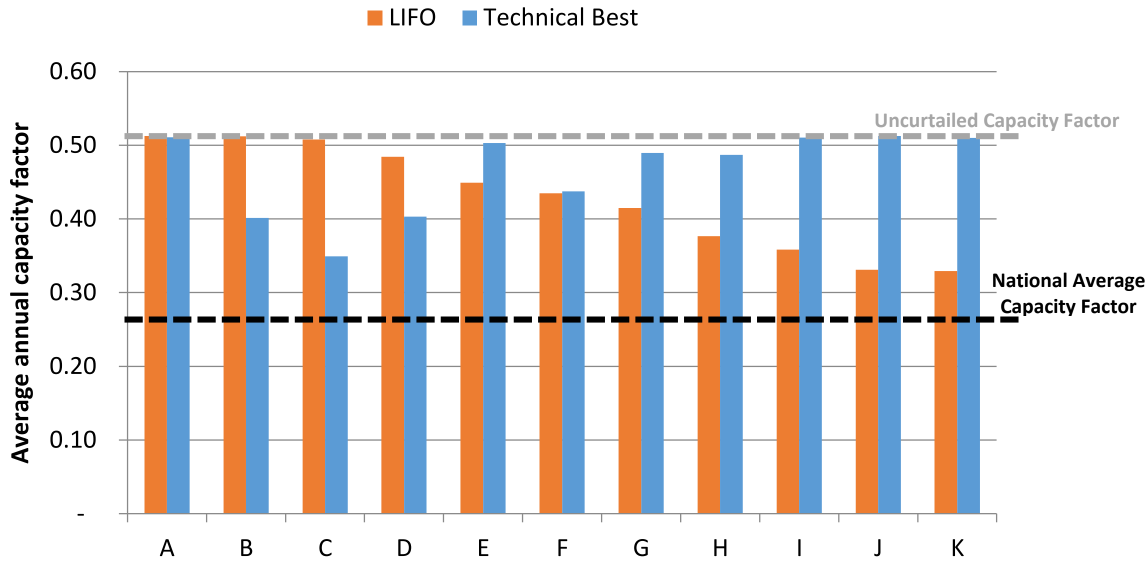

Figure 5-18 Average annual capacity factor for non-firm generators subjected to a 'technical best' curtailment strategy and compared with the original LIFO arrangement

The minimum capacity factor under the technical best arrangement is 0.35 compared with a minimum of 0.33 under the LIFO arrangement. Even though the Technical Best arrangement has a higher overall curtailment when compared with the LIFO base case, larger generators are used to clear the constraint due to sensitivity to losses and are therefore not fully constrained for the same length of time as the smaller generators. This observation is presented by the results in Figure 5-19, and the results match those presented in Chapter Four.

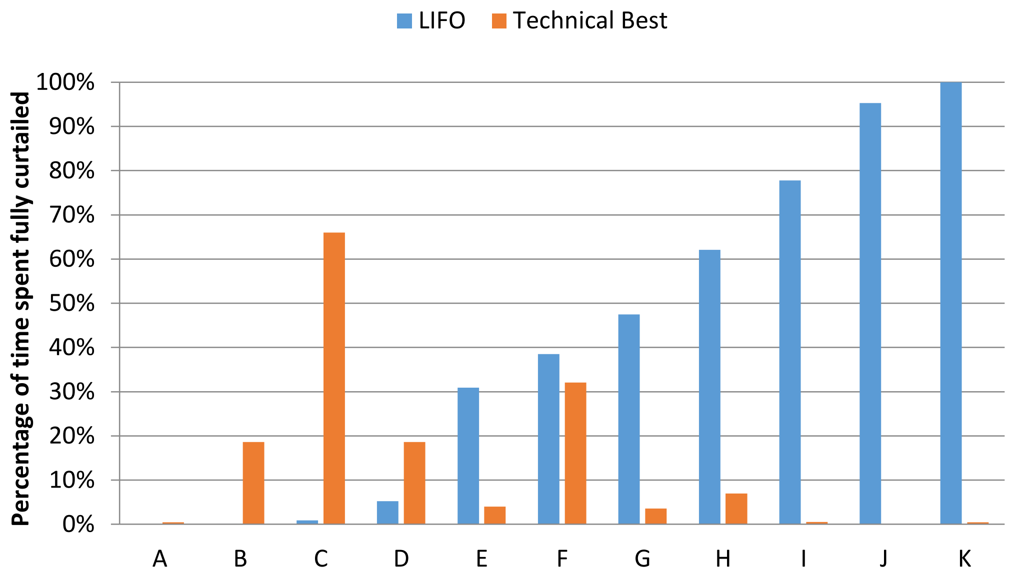

Figure 5-19 Percentage of time spent fully curtailed across one year of operation

5.3.3.3 Non-Market Sensitivity Study #3: Changing the generation mix

In the base case network, the generation mix on the case study network is composed of two groups of wind generation – sub 1 MW and greater than 1 MW. In order to further explore market behaviour, variations of the generation mix are presented.

Generator C which is 2.45 MW, is removed, and in its place, four 500 kW machines and a single 450 kW machine are added to the bottom of the priority stack. The total non-firm capacity remains the same, but the new mix introduces a larger number of small generation on to the network. The new priority order is provided in Table 5-6
Table 5-6. The new generators are connected to the same bus as Generator C. This ensures the same volume of curtailment in this sensitivity study as presented in the base case examples.

Table 5-6 Generator information with additional 500 kW wind generators added to curtailment stack

Gen ID	Capacity (MW)	Priority Order
A	0.9	1
B	2.3	2
D	4.5	3
E	0.9	4
F	0.9	5
G	0.9	6
H	1.8	7
I	0.9	8
J	0.9	9
K	0.9	10
X1	0.5	11
X2	0.5	12
X3	0.5	13
X4	0.5	14
X5	0.45	15

The results of the applying non-firm curtailment arrangements to the new generator mix are shown in Figure 5-20 and Figure 5-21.

The total curtailed energy ranges from 10GWh to 11.1 GWh, which equates to 2.7% of the uncurtailed volume and 4.5% of the net demand/generation. The small generators which are now first to curtail under a LIFO curtailment strategy are located relatively far away from the constraint and this reduces losses on the network. The LIFO arrangement has the lowest total volume of energy curtailed.

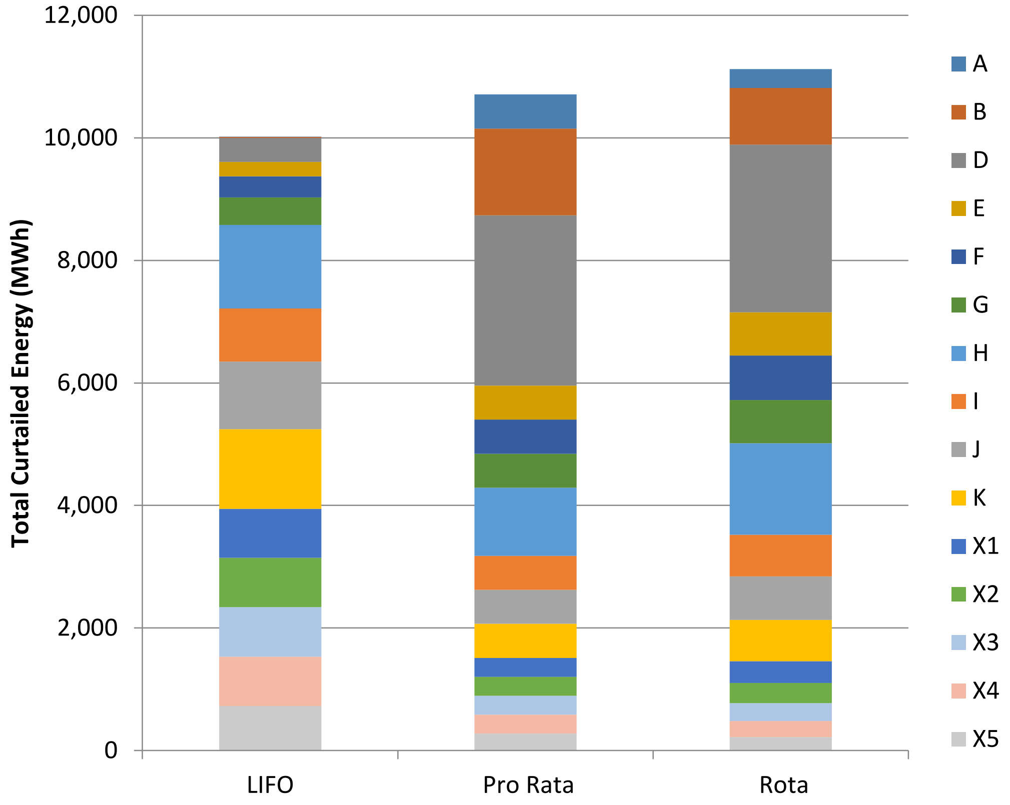

Figure 5-20 Total curtailed energy for sensitivity study #3

The total volume of non-firm generators has not changed, only the number of generators across which it is distributed and therefore the results are similar to the base case example. Generators X1 – X5 are used to relieve the majority of network constraints across the year and therefore have the minimum capacity factor of 0.33. Under a Pro Rata arrangement, the capacity factor is 0.44 as it is under the base case generator mix. While the number of generators has increased, the capacity remains the same and therefore the proportion of curtailment is the same.

The Rota capacity factors range from 0.42 to 0.47. This is a slightly larger range than in the previous example; however this can be explained by the increased number of generators. Now each generator will spend less time at the bottom of the curtailment stack. For example, when there are 11 generators, the time spent in each position is 9.09%, however when there are 15 generators, the time spent in each curtailment position is 6.67%.

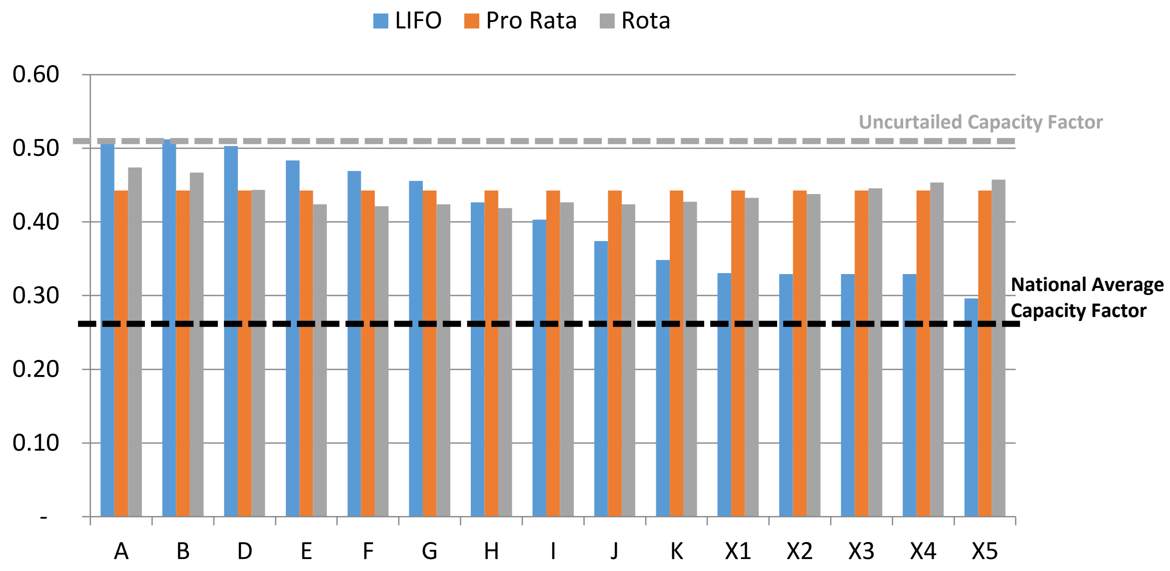

Figure 5-21 Average annual capacity factor for non-firm generators in study #3

5.3.3.4 Non-Market Sensitivity Study Conclusions

The sensitivity studies presented in this section have demonstrated the impact of varying a number of different factors on the curtailment of wind generators. A summary of the results is presented in Table 5-7.

Table 5-7 Comparison table of non-market sensitivity study results compared to the LIFO base case

	Generation (MWh)		Demand (MWh)	Losses (MWh)		Energy Curtailed (MWh)
	Pre	***Post***		***Pre***	***Post***	
Base Case	388,345	378,910	149,295	51,991	45,868	9,429
Study #1	388,345	377,015	149,295	51,991	44,093	11,327
Study #2	388,345	376,887	149,295	51,991	43,917	11,458
Study #3 LIFO	388,345	378,323	149,295	51,991	45,308	10,017
Study #3 Pro Rata	388,345	377,637	149,295	51,991	44,651	10,707
Study #3 Rota	388,345	377,220	149,295	51,991	44,455	11,120

Study #1 demonstrates that the position of generators in the LIFO stack is not only important in terms of order of curtailment, but also in terms of capacity i.e. how much curtailment is required and the size of generation that will be curtailed first. In Study #2, technical best arrangements highlight the impact of network losses and the impact this has on overall curtailment. The optimal network configuration doesn't necessarily lead to the best scenario for individual generators. Generators B, C and D would claim unfair discrimination in this case, as they are selected to clear constraints during the 'technical best' arrangement.

The properties of each individual network will vary and curtailment results will vary under each arrangement depending on size of constraint, branch topology and location of generation in relation to the constraint. The addition of more generators to the generation mix in Study #3 further highlights the impact of the LIFO curtailment order by changing the size and position of generators in the stack. The impact of having larger or smaller generators at the bottom of the curtailment stack shows the influence this has over total curtailment, and how many generators are impacted by curtailment.

5.4 Market PoA Modelling

The market models base case uses the case study presented in Figure 5-5 with a single GSP constraint. There are three market arrangements proposed in Chapter Three: Pay-as-Bid (PAB), Curtailment Market Clearing Price (CMCP) and Fixed Price. This section will focus on the characteristics of PAB and CMCP arrangements and the impact certain bid behaviour has on the curtailment of wind generators. The non-firm arrangement results i.e. LIFO, Pro Rata and Rota will be used in place of a 'Fixed Price' market arrangement to compare the possible variations of curtailment costs in the final comparison of all arrangements.

Similar to those explored for non-market arrangements, a sensitivity analysis of the market models will look at the impact of change in pre-curtailment profit levels, the size of bid intervals, game playing and changes to generation mix.

5.4.1 Market PoA Study Base Case

The bid behaviour is demonstrated in Figure 5-22 below. This CMCP model uses the same bid methodology as the PAB model. The curtailment results will be the same, however the cost of curtailment differs, as explained in Chapter Four. The model curtails generation in 30min intervals therefore the system price is given for each 30 minute interval. A daily system price value could over estimate costs by assigning a high clearing price to all 48 constraint periods when this was not necessarily the case in practice. For this reason, a daily system price is not considered in this analysis. The system price is determined by calculating the maximum price paid for an accepted bid during each 30 minute period. The system price for each period across the year is shown in Figure 5-23.

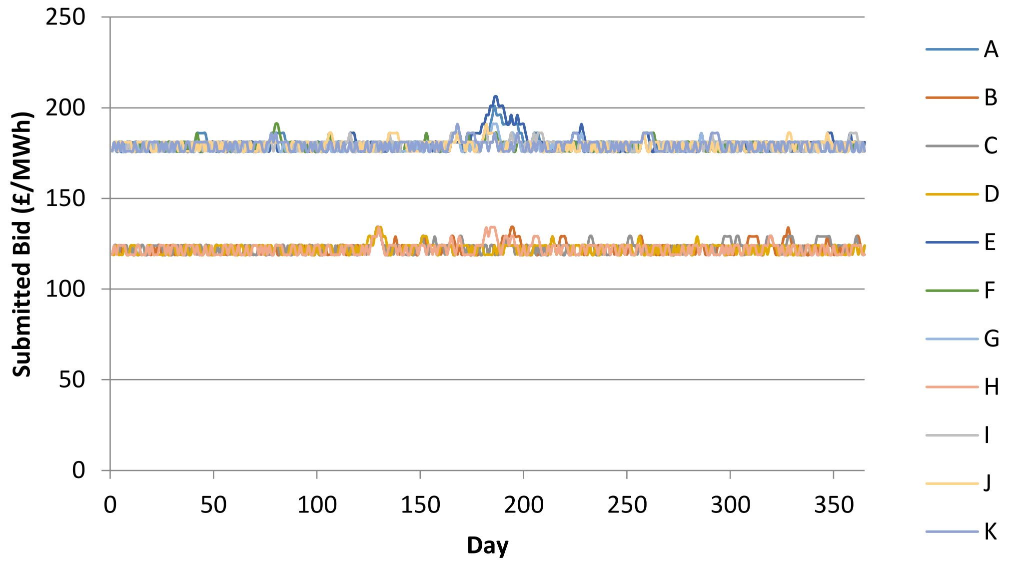

Figure 5-22 An example of typical bid behaviour for non-firm generators under a market PoA

The larger generators receive a lower FIT subsidy when compared with the smaller generators who receive up to double the amount of payment per MWh. This results in two distinct groups of bids. The lower priced bids will be selected to resolve network constraints, so when the system price is calculated it spends the majority of time between £120 - £130/MWh but during periods of high constraints i.e. when more generators must be curtailed in order to relieve the constraint, the system price jumps to higher bid levels i.e. in the region of £176/MWh. This is indicated by the spikes in Figure 5-23.

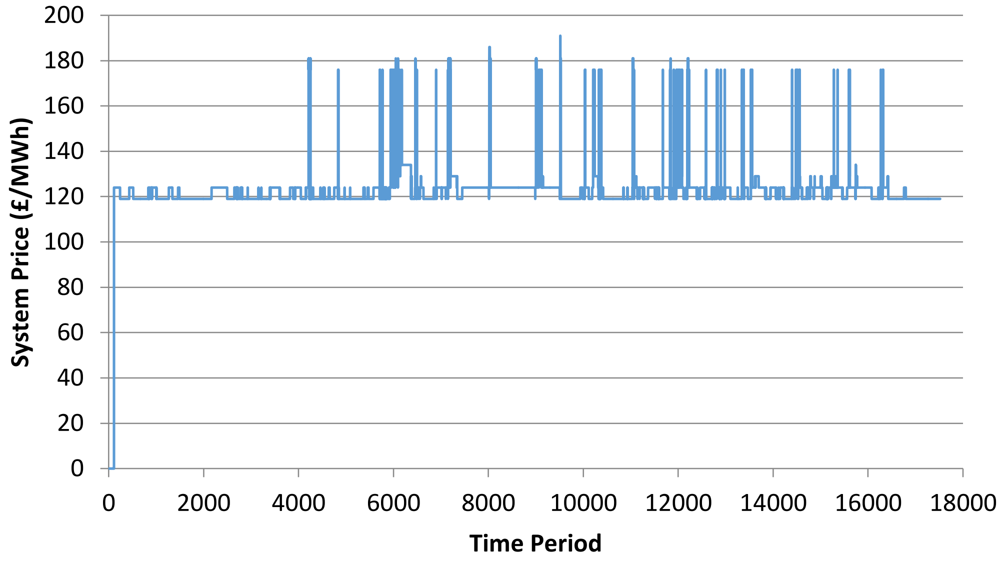

Figure 5-23 System price for the base case market model

Total curtailment volumes for the base case market based PoA are shown in Figure 5-24. The total volume of curtailment is 11.7GWh. This accounts for 3% of the uncurtailed output, and 5% of net demand/generation. Larger generators have a lower bid price, as they receive lower subsidy payments per MWh. This results in the market PoA selecting the larger generators for the majority of the curtailment instructions because they have submitted the lowest bids in to the market i.e. Generators B, C, D and H.

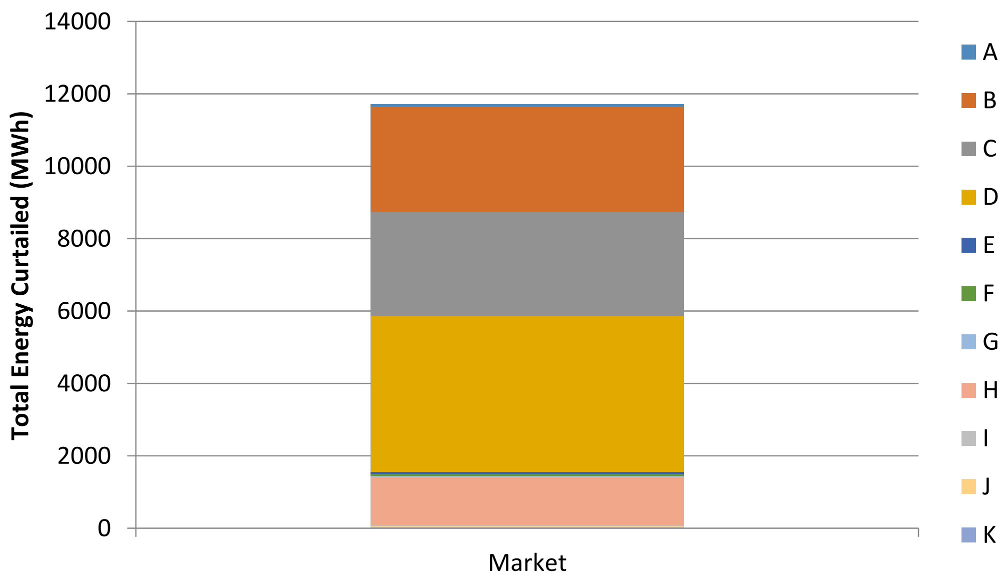

Figure 5-24 Total curtailment (MWh) for market arrangements

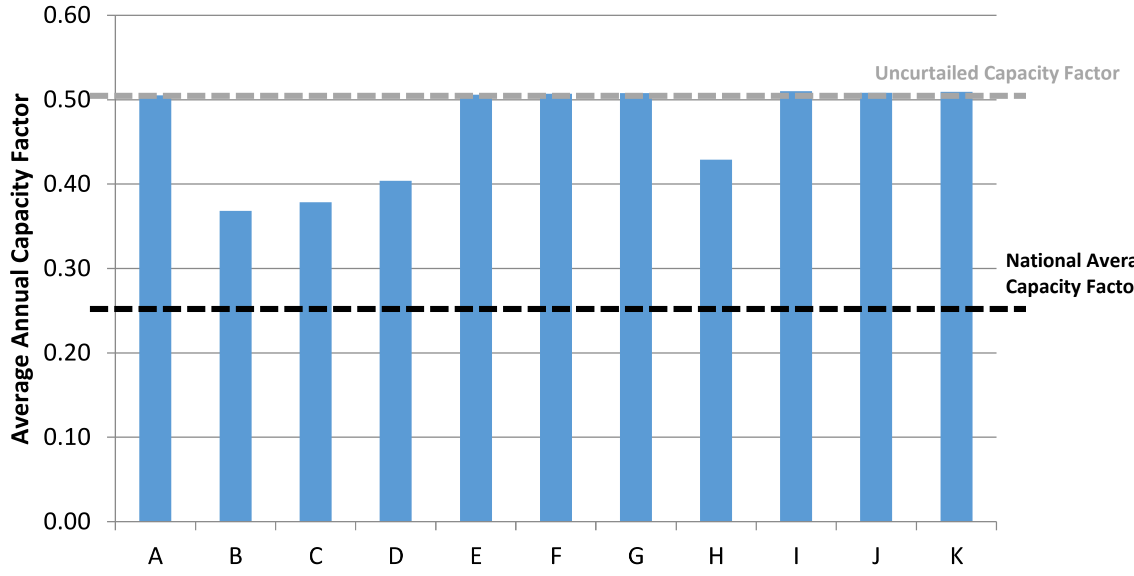

Figure 5-25 Average annual capacity factor for a market arrangement

The average annual capacity factors are shown in Figure 5-25. Generators B, C, D and H are curtailed across the year as they submit the lowest cost bids. The other generators do not experience a reduction in capacity factor. While they are constrained during the analysis period, the volume of curtailment is very low when compared with Generators B, C, D and H and does not have an impact on average annual curtailment.

The lowest capacity factor is 0.37 experienced by Generator B. More detailed analysis of the curtailment shows that of the 3,332 constrained periods, Generator B is fully curtailed i.e. has an output of zero, for 72% of those constrained periods. While this seems like a high percentage of time for Generator B to not be operating, the generator is still receiving curtailment payment commensurate with revenue from energy and subsidy certificates. The reduced operating time could also benefit the generator in terms of O&M costs and asset degradations although there is an argument that the increased curtailment instructions may have a negative effect on the turbine operationally due to additional stop/start actions. Generators B, C and D are the largest generators connected to the network and are therefore able to clear the majority of the constraints. Large generators receive a lower subsidy rate through the FIT mechanism. The impact of this on the cost of curtailment is shown in Table 5-8 and the total curtailment costs for each Generator shown in Figure 5-26.

Table 5-8 Summary of total and average constraint costs for market arrangements on a network with a single GSP constraint

	PAB	CMCP
Total Constraint Costs (£k)	1,448	1,581
Average Constraint Costs (£/MWh)	124	135

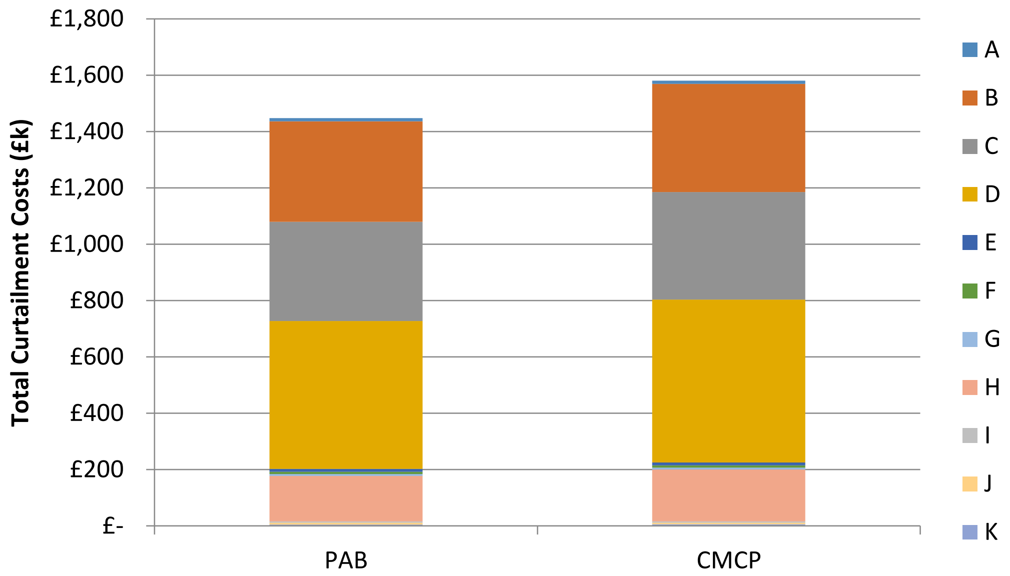

Figure 5-26 Total curtailment costs for the base case market examples

As demonstrated by the total curtailment graph in Figure 5-24, Generators B, C, D and H account for the majority of constraint payments. The curtailment costs for the CMCP arrangement are higher when compared with the PAB arrangement. This can be explained by the market using the highest price at which constraints are cleared to pay compensation to all generators. The difference between PAB and CMCP is not greater, as the main generators used to clear the constraint are closely related in terms of bid costs. The difference in cost is made during periods of high constraints when the system price increases. The advantage of using the PAB method for compensation is that it brings down the cost of curtailment during high constraint periods because generators who submit lower bids, and still paid than lower levels of compensation.

5.4.2 Sensitivity Studies of Market PoA

Similar to those studies explored for non-market arrangements in Section 5.3.3, this section will look at the impact of changing a number of aspects regarding the market arrangements.

There are four sensitivity studies analysed in this section. Firstly, the pre-curtailment levels are varied to assess the impact on curtailment cost and capacity factor of the generators. The second sensitivity study will look at the size of the bid step change in each 24 hour period. The base case assumes a step change of £5/MWh, the sensitivity study will vary this firstly between £0-5/MWh and then £0-10/MWh. The third study will assess the impact of game playing on market behaviour. One or more generators will submit bids much higher than calculated pre-curtailment values. Finally the fourth sensitivity study will look at the impact a change of generation mix will have on a curtailment market.

5.4.2.1 Market Sensitivity Study #1: Changing Pre-curtailment Cost Values

The pre-curtailment profit is the profit level which all generators are seeking, however if the opportunity arises, generators will seek to gain more. The pre-curtailment bid levels have a key influence on the bid behaviour of generators and therefore, the application of curtailment in the markets. Currently there are only two pre-curtailment profit levels. To analyse the impact of this, the pre-curtailment profit levels will be varied.

There are 13 variations on the base pre-curtailment profit levels. Details of the changes made to pre-curtailment profit levels are given in Table 5-9 . Where changes to the base case values have been made, the value is highlight in red. Models I – VI are based on increases in FIT levels. Models I-III apply a 5% increase to one or more generators, and Models III – VI apply a 10% increase to FIT level for one or more generators. Models VII – XII demonstrate decreases on FIT levels. Models VII – IX apply a 5% decrease to one or more generators. Models X-XII applies a 10% decrease to FIT levels for one or more generators. The final model, Model XIII selected pre-curtailment levels using a random number function in Matlab.

Table 5-9 Pre-curtailment bid prices used in sensitivity study of market arrangements for each generator (A to K) and each sensitivity case I-XIII)

	A	B	C	D	E	F	G	H	I	J	K
BASE	176	119	119	119	176	176	176	119	176	176	176
I	176	119	119	**122**	176	176	176	119	176	176	176
II	176	119	119	119	176	176	176	119	**181**	176	176
III	176	119	119	**122**	176	176	176	**122**	**181**	176	176
IV	176	119	119	**124**	176	176	176	119	176	176	176
v	176	119	119	119	176	176	176	119	**187**	176	176
VI	176	119	119	**124**	176	176	176	**124**	**187**	176	176
VII	176	119	119	**117**	176	176	176	119	176	176	176
VIII	176	119	119	119	176	176	176	119	**171**	176	176
IX	176	119	119	**117**	176	176	176	**117**	**171**	176	176
X	176	119	119	**114**	176	176	176	119	176	176	176
XI	176	119	119	119	176	176	176	119	**165**	176	176
XII	176	119	119	**114**	176	176	176	**114**	**165**	176	176
XIII	**162**	**121**	**123**	**136**	**156**	**87**	**139**	**88**	**89**	**146**	**122**

The bid behaviour of Models I – XII is similar to that demonstrated in Figure 5-22 for the base case example. An example of bid behaviour of Model XIII is given in Figure 5-27.

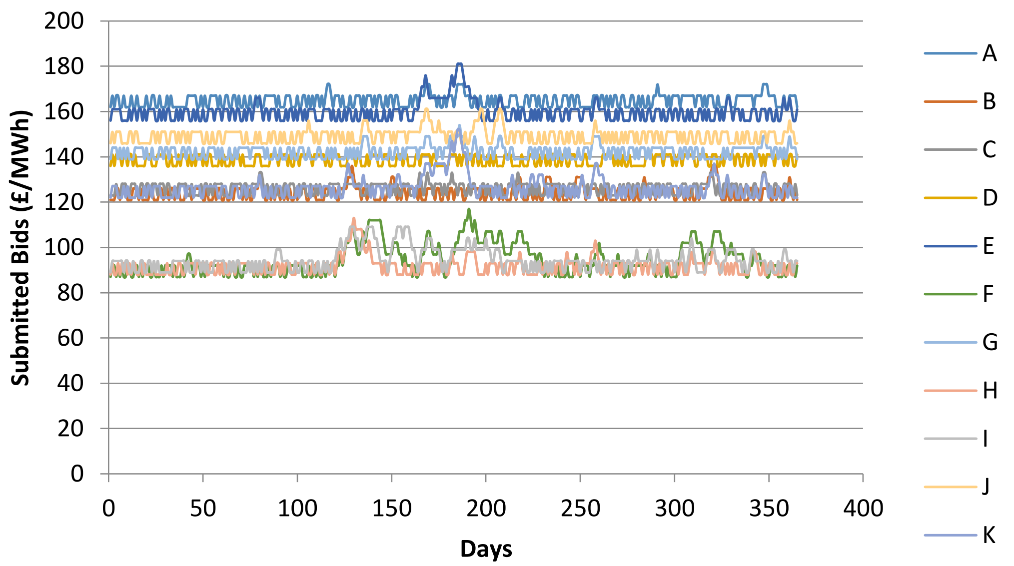

Figure 5-27 Bid behaviour for market sensitivity model XIII where random pre-curtailment values are used

When the starting bids are random, there is a wider range of prices than those presented in Figure 5-23. The prices range from £87/MWh up to £162/MWh. This spread of bids will result in a different system price behaviour, which is shown in Figure 5-28. The CMCP for model XIII has a wider range of prices across the year and less of the large price spikes demonstrated in other models. For models I – XII, the CMCP varies in a similar manner across the year for the different pre-curtailment levels. The spikes in the graph reflect half hour periods where high volumes of curtailment are required. Smaller generators with higher bid prices are required to clear the constraint and this will therefore increase the system price.

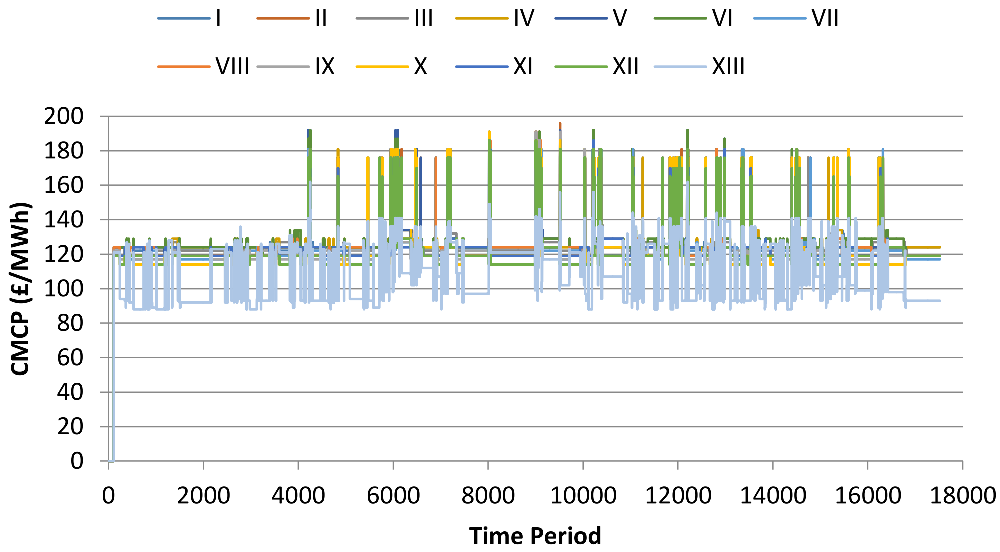

Figure 5-28 System price changes for each of the sensitivity studies

The total curtailed volume is given in Figure 5-29. The value varies slightly due to network losses, but not significantly. For Models I – XII, the same four generators, B, C, D and H, are used in all arrangements to clear the constraints. While prices are varied, the larger generators still have the lowest cost bids and are therefore by the OPF to relieve the constraints. For Model XIII, the random costs result in a different distribution of curtailment when compared to Models I to XII, hence the difference in total curtailed energy for this model. Generators F, H and I are now the lowest cost generators are will be used to clear the constraints in the first instance. Following on from these generators, Generators B, C and K are the next group of generators to be asked to curtail.

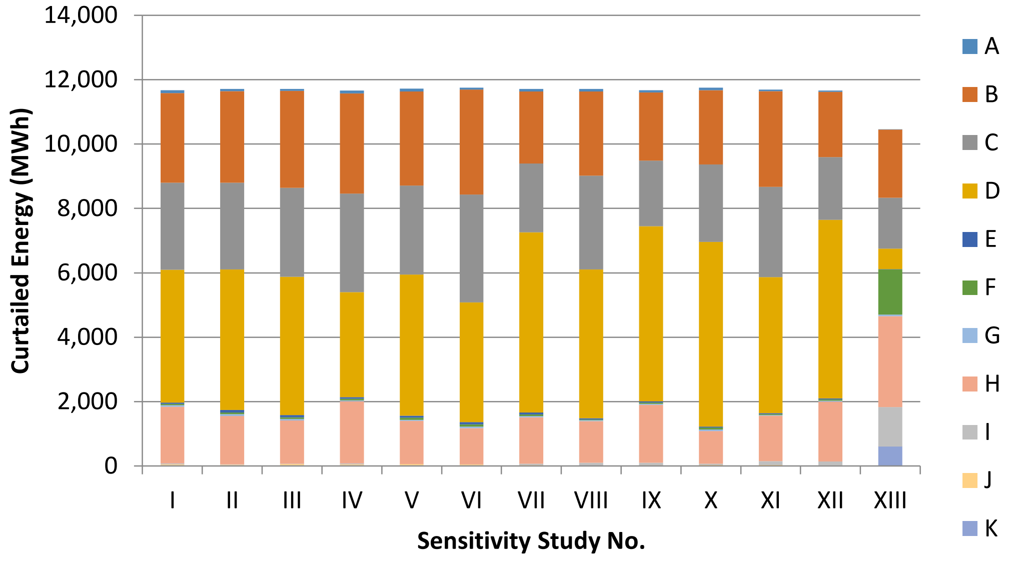

Figure 5-29 Total volume of curtailed energy for market sensitivity study #1

The average annual capacity factor of generators in Model I is compared with capacity factors in Model XIII in Figure 5-30. The minimum capacity factor for Model I is 0.37, which is greater than the minimum capacity factor for Model XIII of 0.33. This is due to the size of the generators used to clear the constraints first – using larger generators results in a higher minimum capacity factor. This result was also demonstrated in the non-market arrangement sensitivity study where the LIFO order was reversed (as shown in Figure 5-15).

Figure 5-30 Average annual capacity factor for Model I and Model XIII for the market arrangement sensitivity study

The total curtailment costs for both PAB and CMCP market arrangements are shown in Figure 5-31 and Figure 5-32 respectively. The CMCP arrangement results in an increase in total and average constraint costs for all models. From the CMCP chart in Figure 5-28, it is clear that the system price is typically in the range of the lowest priced generators as they clear the majority of constraints across the year however there are instances where the clearing price jumps to the higher group of pre-curtailment prices because the constraint requires larger volumes of curtailment than the initial group of lower priced generators can provide.

If all 11 non-firm generators had a similar bid price, the impact of using a system price would not be so significant. The distinct split between generators greater than or less than 1 MW i.e. the high cost generators, results in the jump in compensation payments during periods of high constraint. This observation is partially artificial due to the costs assumptions made in the definition of the problem i.e. all costs are equal with the exception of the subsidy level. The curtailment behaviour does reflect the increased need for curtailment on the network and possibly, the need for further improvements to the system. This would be the decision of the network owner and operator whether the cost of curtailment was justified when compared with traditional network reinforcements.

The impact of changing the pre-curtailment price is not significant for Models I to XII because it does not have a substantial impact on the bid behaviour, and the total costs and system price are only shifted higher or lower by a small factor. The small volume of curtailment and small number of generators may factor in this outcome. Should there be higher levels of curtailment required, this could result in more of the generators required to clear the constraint more frequently, which would also increase the curtailment market clearing price.

For Model XIII, the costs are lower for both arrangements when compared with Model I – XII. . The lowest priced generator is £87/MWh, which compares with a price of £114-119/MWh for Model I – XII. It is also evident from the results graph that the average cost of curtailment is significantly lower. While the curtailment is the same in all cases, the cost to the system operator could be very different depending on the compensation method used. This issue will be discussed in more detail in Chapter Six with the presentation of a business model of how network operators may seek to recover the costs of operating a curtailment market at distribution level.

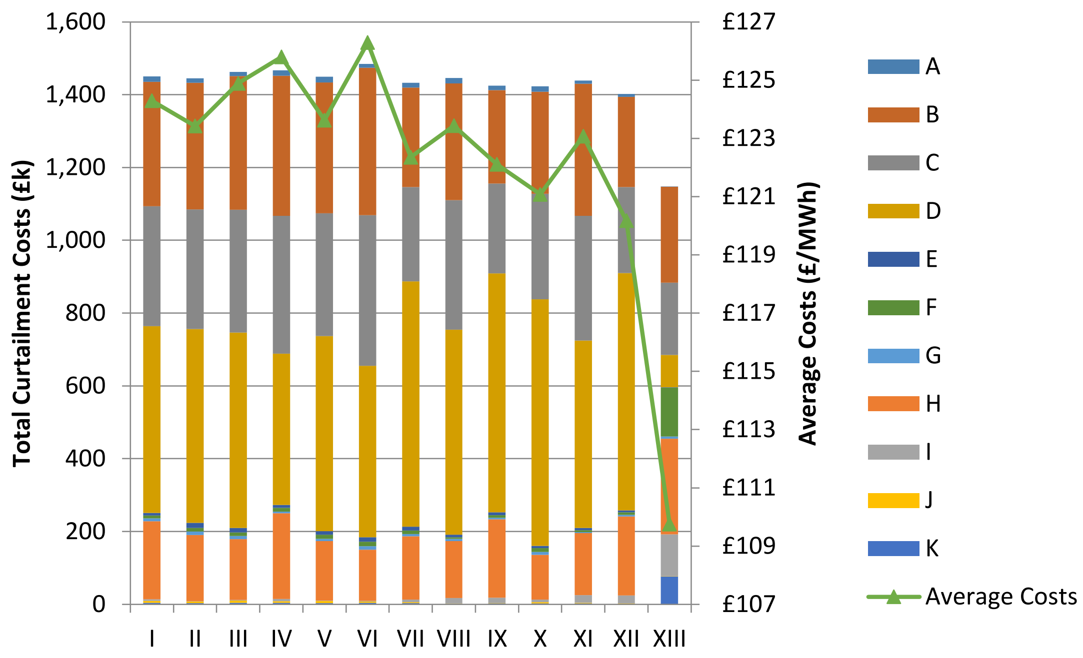

Figure 5-31 Total constraint costs for a one year study of PAB market arrangement on case study network

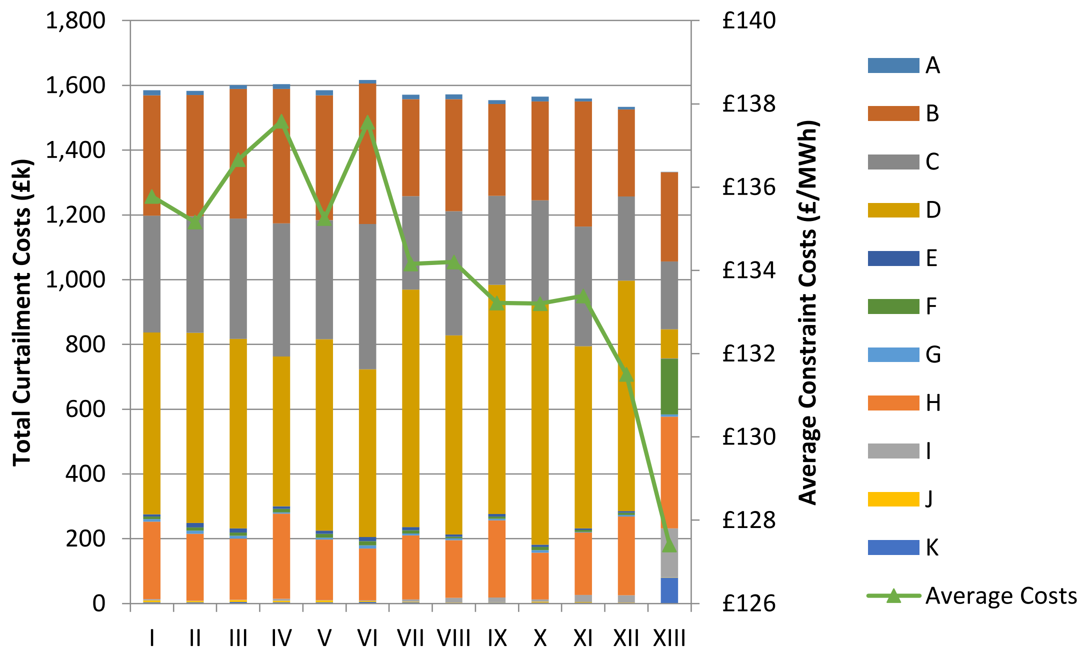

Figure 5-32 Total constraint costs for a CMCP market arrangement

5.4.2.2 Market Sensitivity Study #2: Randomise Bid Changes

In previous studies, the bid has increased or decreased by £5/MWh, or stayed the same depending on the curtailment result from the previous time step. In this sensitivity study, random bid changes will be applied to test the impact of varying bid step changes. There are two scenarios considered in this sensitivity study:

- Allow bids to increase/decrease by a whole number between 0 and £5/MWh
- Allow bids to increase/decrease by a whole number between 0 and £10/MWh

The bid behaviour of each scenario is shown below. The pattern is similar to that demonstrated for previous examples, but the jump between values is no longer uniform. The maximum bid values are increased in the 0-10 bid scenario. Comparing the two graphs in Figure 5-33 and Figure 5-34 it is clear that the 0-10 scenario gives a more volatile bidding pattern with a wider range of bids in each of the two bid groups. However, there remains no crossover of bid prices between the two subsidy group levels.

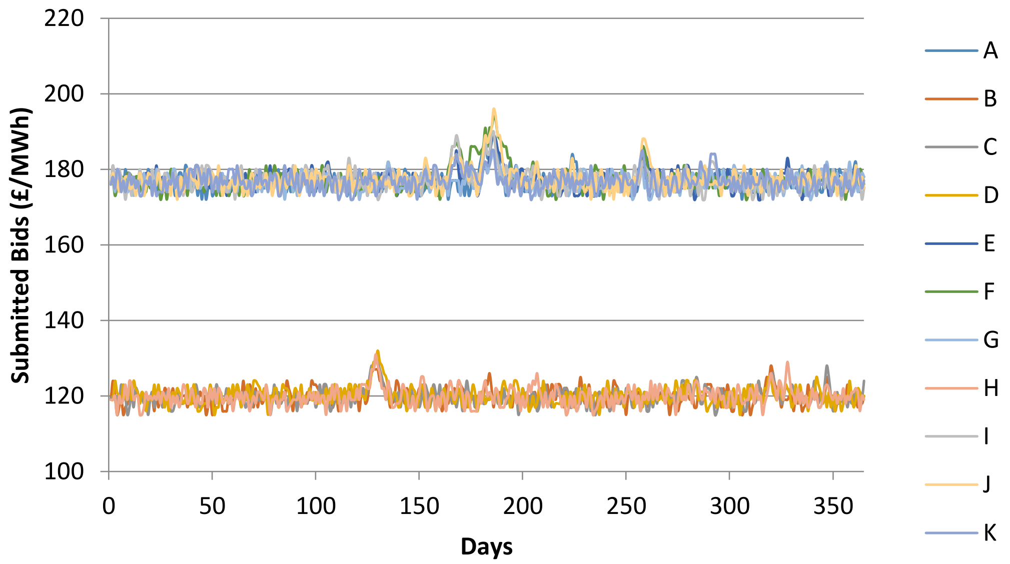

Figure 5-33 Bid behaviour when bids are changed by a value between 0 and 5 during each time period

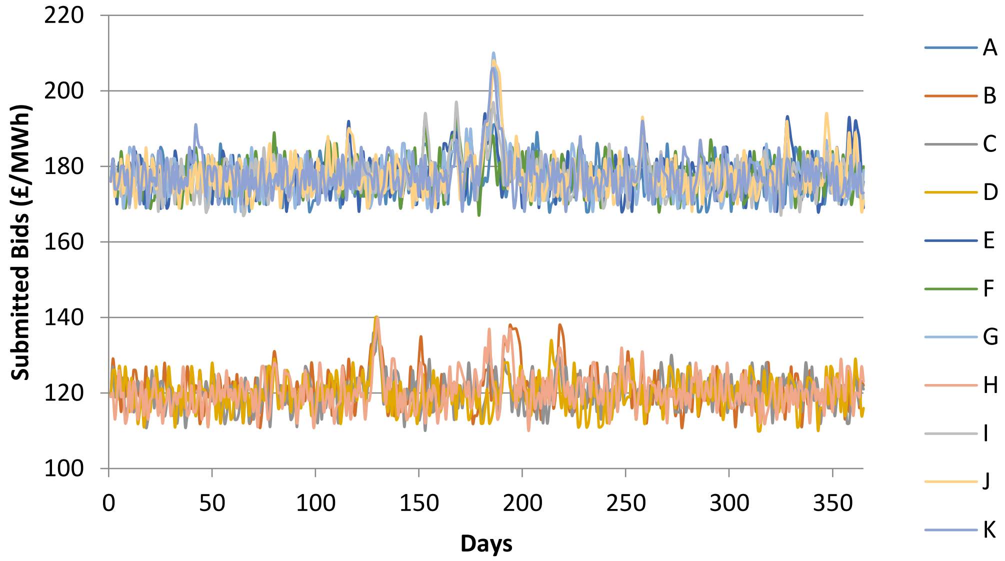

Figure 5-34 Bid behaviour when bids are changed by a value between 0 and 10 during each time period

The system price for both bid scenarios is shown in Figure 5-35 below. A similar pattern to that shown in previous examples (Figure 5-23 demonstrates there is no real deviation from the base case example.)

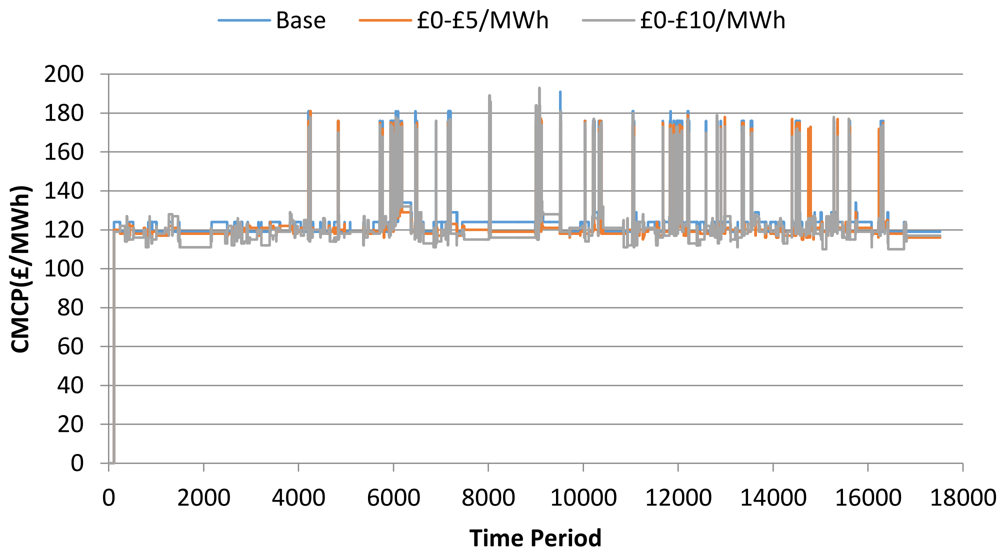

Figure 5-35 System price for each bid change scenario

The total curtailment is shown in Figure 5-36. There is a very small difference in overall curtailment and as shown in Figure 5-26, the larger generators with smaller prices experience the most curtailment – Generators B, C, D and H.

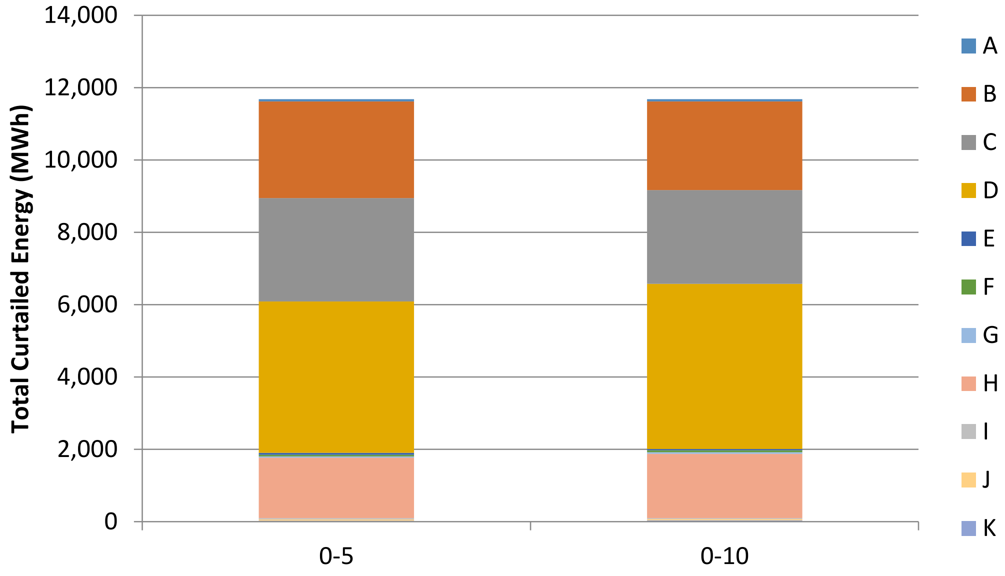

Figure 5-36 Total curtailed energy for each scenario

In terms of cost of curtailment, the CMCP is again the more expensive arrangement in both scenarios. The average costs for the £0-£5/MWh are lower than those experienced in the base case. This can be explained by the size of the bid change being less than £5/MWh. This also brings the total costs down lower than when compared with the base case.

Table 5-10 Total and average curtailment costs

	£0 - £5/MWh		£0-£10/MWh	
	PAB	CMCP	PAB	CMCP
Total Constraint Costs (£k)	1,415	1,528	1,409	1,554
Average Constraint Costs (£/MWh)	121	131	121	133

Figure 5-37 Total curtailment costs for market PoA when bid changes are randomised

The impact of randomising the bid changes has little effect on the overall curtailment outcome. The result are similar to the base case results. By allowing generators to select a number between 0 and 5, or 0 and 10 to increase or decrease a bid by, this lowers the overall costs slightly but not significantly. The CMCP and bid behaviour is also similar to the base case.

5.4.2.3 Market Sensitivity Study #3: Game Playing

A common problem in markets is 'game playing' i.e. where one or more players take advantage of a weakness in the market to receive a higher profit than would be received under fair market circumstances. This sensitivity study will analyse what happens in a market with one or more 'game playing' generators.

- One generator bids at a higher than expected pre-curtailment profit level
- Two generators bid at a higher than expected pre-curtailment profit level
- Four generators bid at a higher than expected pre-curtailment profit level

The starting bids for each gaming sensitivity study are provided in Table 5-11.

Table 5-11 Starting bid level for market sensitivity study #3 which looks at generators 'gaming' the market

	A	B	C	D	E	F	G	H	I	J	K
BASE	176	119	119	119	176	176	176	119	176	176	176
GAME I	176	119	119	**300**	176	176	176	119	176	176	176
GAME II	176	119	119	**300**	176	176	176	119	300	176	176
GAME III	176	119	119	300	300	176	176	119	176	250	225

In the first scenario, Generator D initiates the bid price at £300/MWh. The bid behaviour is shown in Figure 5-38. As before, the bids are spaced far enough apart that the price groups do not cross over due to the difference between subsidy payments. Generator D is an outlier to the other generators.

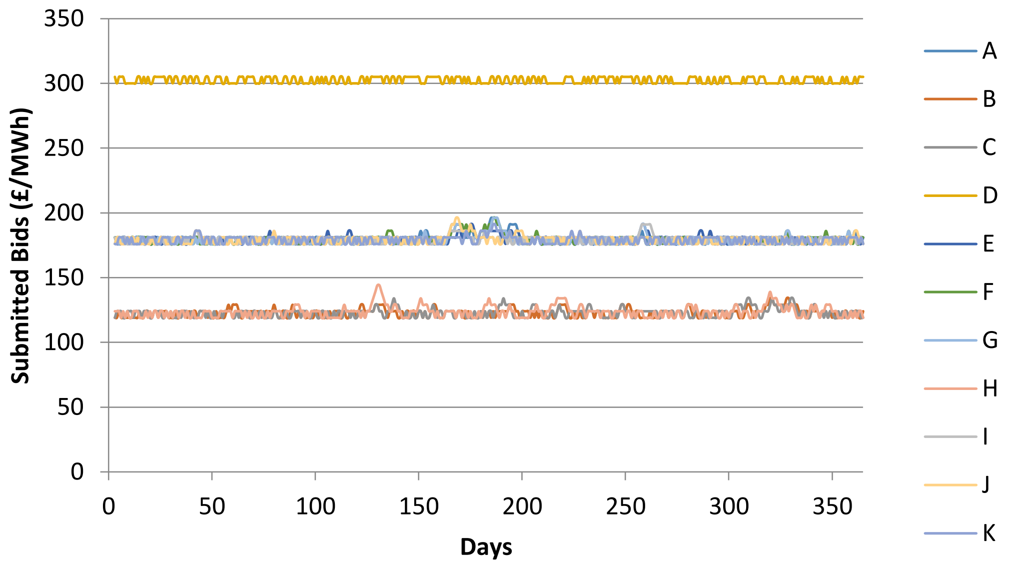

Figure 5-38 Bid behaviour in a market arrangement when one generator bids at a high price level

The impact of this 'gaming' on the total curtailed energy is shown in Figure 5-39. As Generator D is now at a much higher price, it is no longer selected to help clear the network constraints. Generators B, C and H are still used to clear constraints and there is more of a contribution from generators A, E, F, G and I. These changes are apparent when comparing the gaming scenarios with the base case results (first column in Figure 5-39). The groups of generators used to clear the constraints in the base case is quite different to those used in the Game sensitivity studies, demonstrated by the colour groups in the graph.

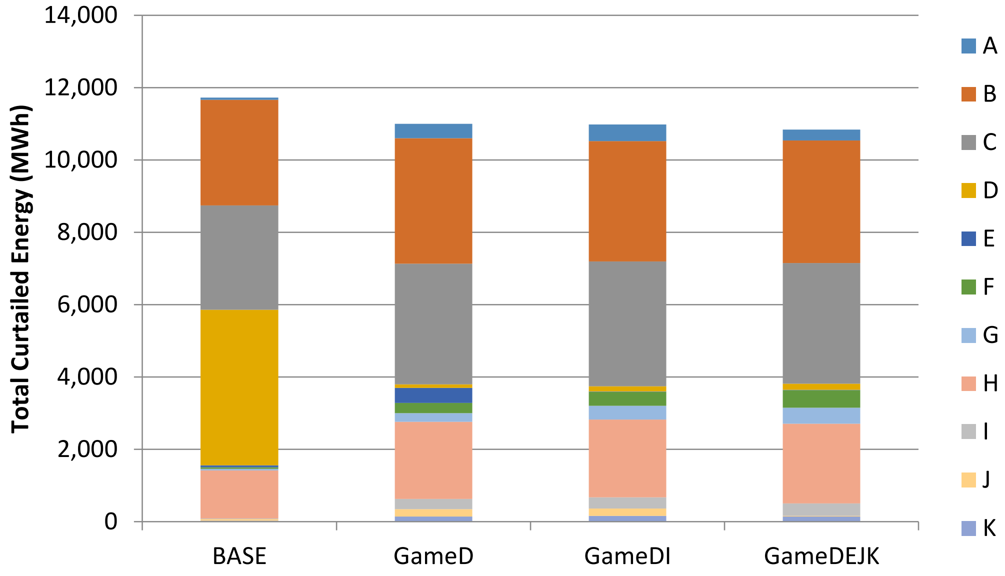

Figure 5-39 Total curtailed energy for market arrangements with generator gaming scenarios

In terms of costs, the outlying generator does result in peaks for the CMCP. Generator D is used to resolve constraints during periods of high constraints when the network has no other option but to curtail all available non-firm generators. This can be compared with balancing during extreme cases at transmission level. When the system operator has curtailed the lower cost generation and still a network issue remains, the system operator must ask the more expensive generator to curtail. The CMCP for each of the three Gaming scenarios is shown in Figure 5-40. The maximum CMCP in all three scenarios is £305/MWh. Similar to the pattern presented in the base case scenario (see Figure 5-23) the spikes occur during the high constraint periods however because the price of the last generator is much higher than the base case scenario, the maximum peak is increased.

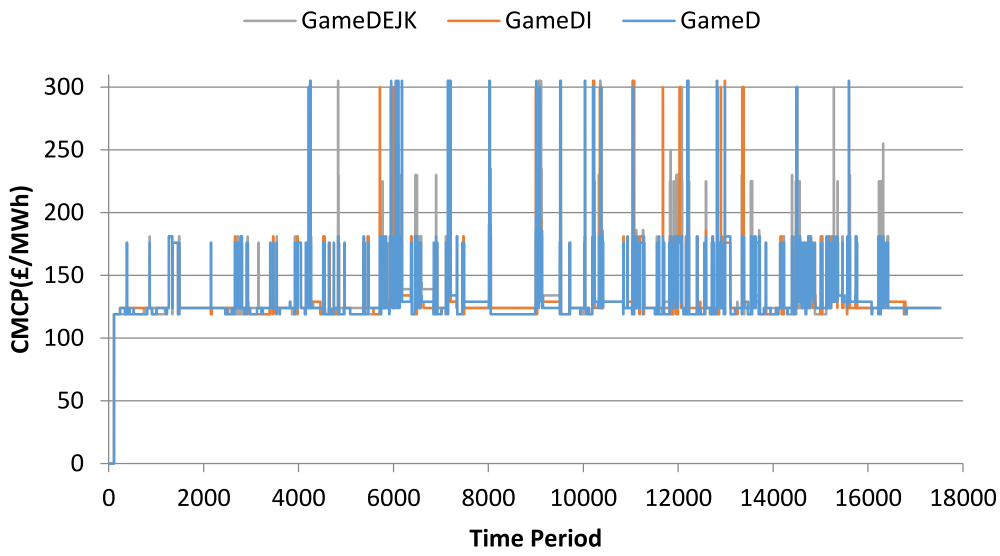

Figure 5-40 CMCP levels for the three gaming scenarios

The overall costs and average costs for the three scenarios are given in Table 5-12. In keeping with the results of the previous market studies presented in this chapter, the CMCP arrangement results in high total and average costs when compared with a PAB arrangement. The more generators bidding at high levels, the higher costs increase with a sharper increase under the CMCP arrangement.

Table 5-12 Total and average curtailment costs for three gaming scenarios

	Game D		Game DI		Game DEJK	
	PAB	CMCP	PAB	CMCP	PAB	CMCP
Total Constraint Costs (£k)	1,484	1,883	1,490	1,921	1,510	1,991
Average Constraint Costs (£/MWh)	135	171	136	175	137	181

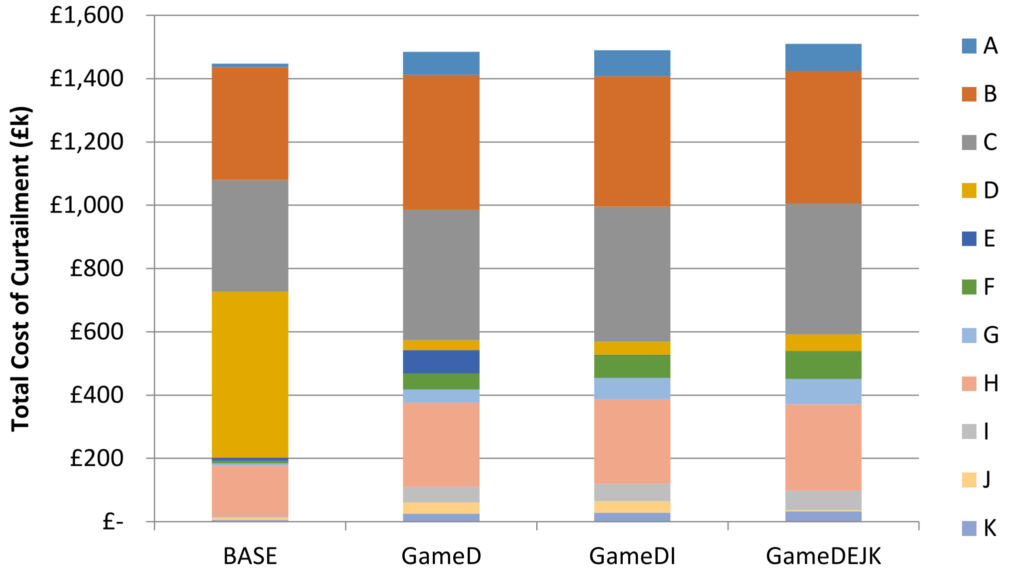

Figure 5-41 Total curtailment costs for PAB market arrangement. The results of the gaming scenarios are compared with the base case results

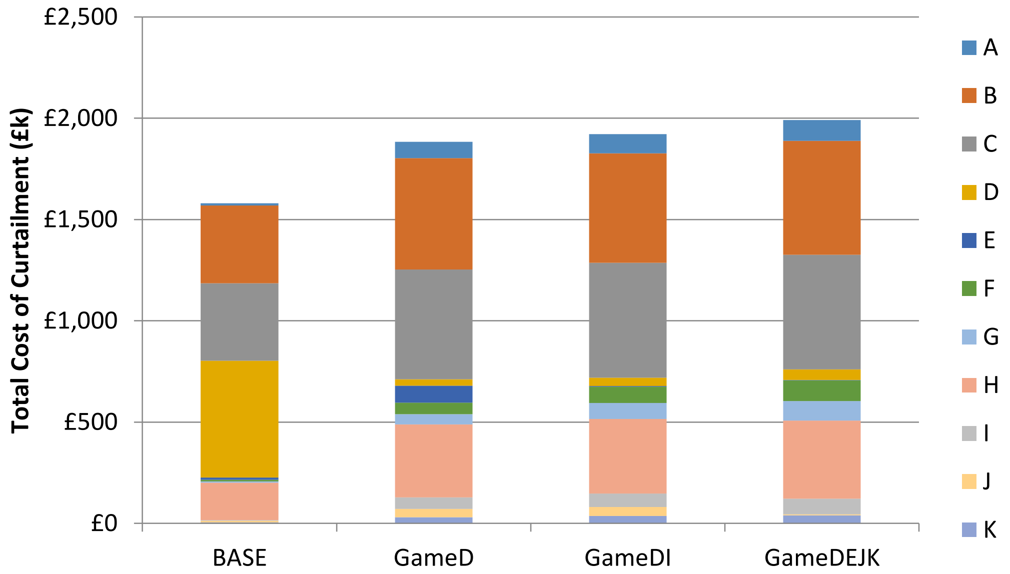

Figure 5-42 Total curtailment costs of a CMCP market arrangement. The results of the game playing scenarios are compared with the base case results

The total curtailment cost results in Figure 5-41 and Figure 5-42 demonstrate that as more generators decide to 'game' the system, curtailment costs could increase sharply. Should all 11 generators decide to bid at 'false' pre-curtailment levels, the network operator could soon find itself paying high compensation costs that are far higher than the costs of network reinforcements. This could in turn increase costs for end users if the network choses to continue with the curtailment market in place of more traditional reinforcements.

5.4.2.4 Market Sensitivity Study #4: Changing the generation mix

This study will analyse the impact of changing the size of generators in the generation mix. Additional small generators will be added in place of a single large generator. This will create a new pricing group and alter the bid behaviour. The study uses the same generation mix as described in Section 5.3.3.3 for the non-market sensitivity study. Generator C is removed and four 500 kW and a single 450 kW machine are added to the network. They are placed at the bottom of the priority stack. The new pre-curtailment prices are given in Table 5-13 below.

Table 5-13 Generation mix used in market PoA sensitivity study #3

Gen ID	Capacity (MW)	Priority Order	Pre-curtailment Profit
A	0.9	1	176
B	2.3	2	119
D	4.5	3	119
E	0.9	4	176
F	0.9	5	176
G	0.9	6	176
H	1.8	7	119
I	0.9	8	176
J	0.9	9	176
K	0.9	10	176
X1	0.5	11	281
X2	0.5	12	281
X3	0.5	13	281
X4	0.5	14	281
X5	0.45	15	281

The small size of generators means that the pre-curtailment profit price is higher than the other two groups due to the high FIT subsidy level. This is shown in Figure 5-43. Now there are three distinct bid groups. The system price is shown in Figure 5-44. As with previous examples, the major spikes in the system price represent periods of high curtailment when the smaller, high priced generators are required to clear the constraints. The volume of curtailment required is the same, but because the larger, lower priced generators are used first the smaller, higher priced generators are not required as often. The CMCP graph demonstrates that this scenario results in more curtailment of the second group of generators i.e. those which bid at £176/MWh.

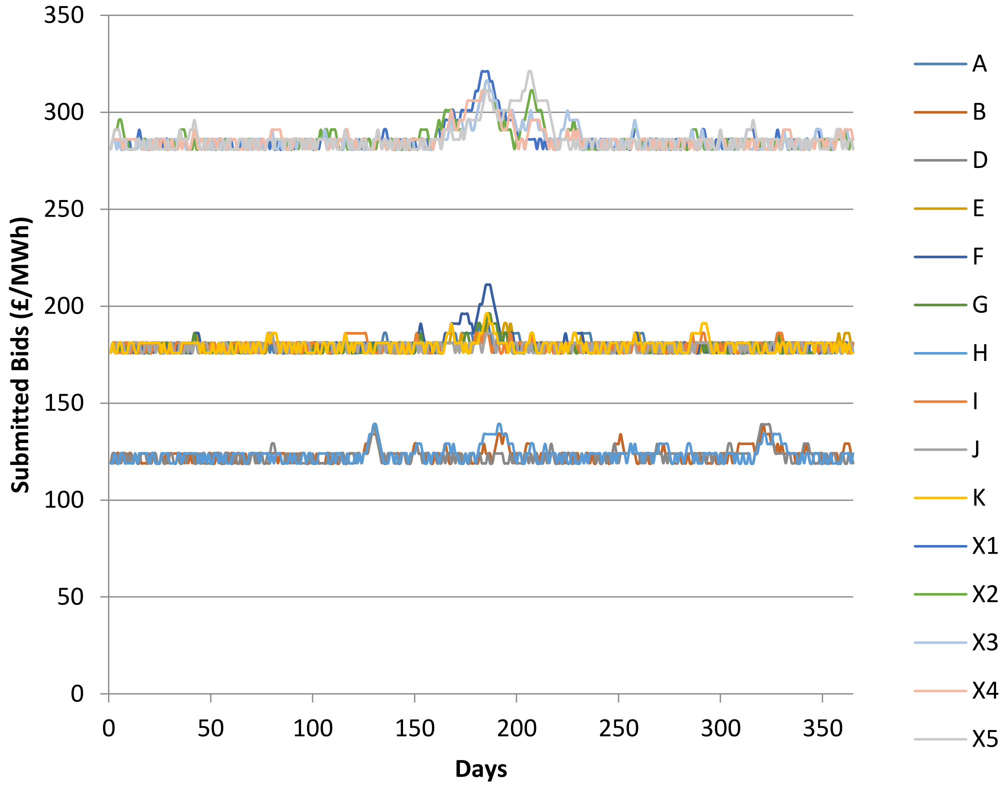

Figure 5-43 Bid behaviour of a market arrangement with additional small generators added to the generation mix

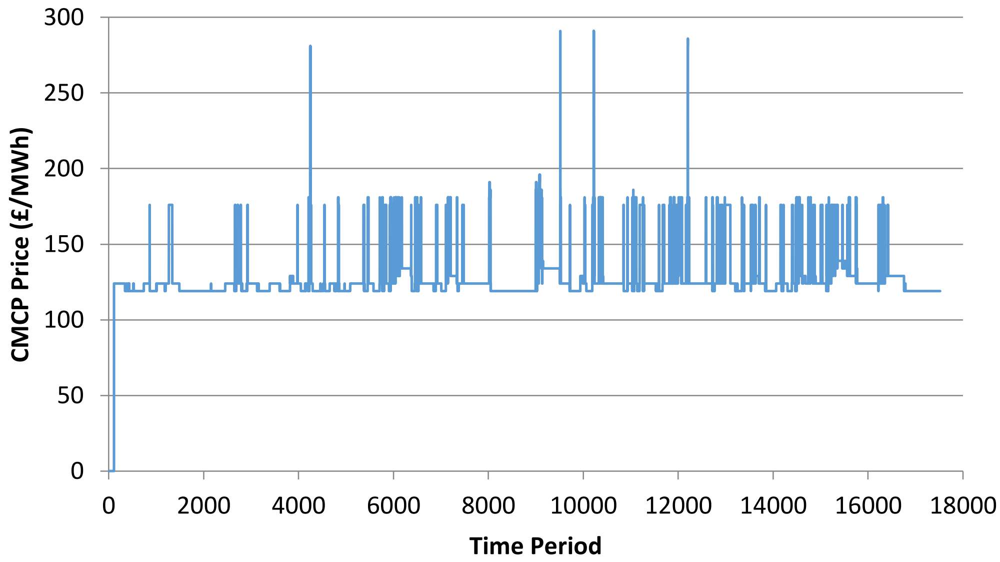

Figure 5-44 The CMCP for a scenario with additional small generators in the generation mix

The total curtailed energy results 7are shown in Figure 5-45. Generators B, D and H are still used to clear the majority of the constraints with generators A, E, F, G and I filling the gap left by the absence of Generator C in the market curtailment stack. Generators X1 to X5 are only used on a very small number of occasions due to their high bid price.

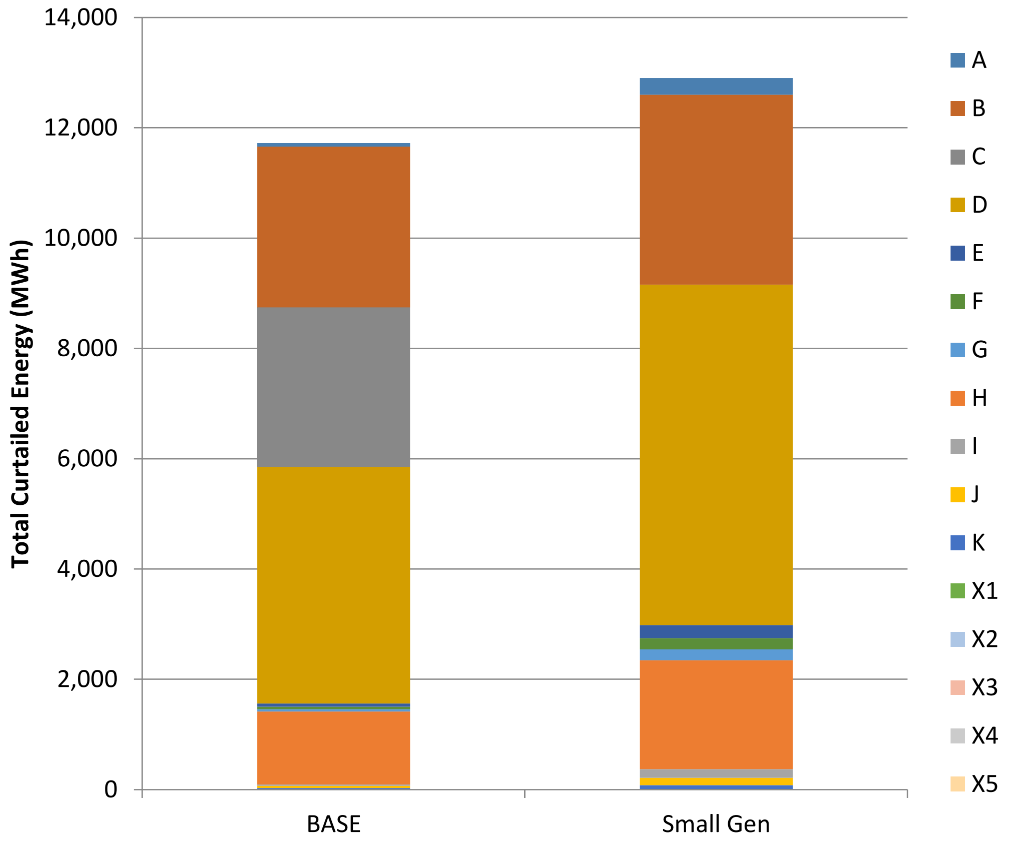

Figure 5-45 Total curtailed energy for the small generator scenario compared with the base case market arrangement

The total costs and average costs for this scenario are given in Table 5-14 and Figure 5-46. The cost of the CMCP arrangement is significantly higher than the PAB arrangement. With the system price more frequently placed at £176/MWh and above, the overall system costs have grown when compared with the base case results. This is reflected in the average constraint cost of the CMCP arrangement which is now £152/MWh compared with a base case value of £135/MWh.

Table 5-14 Total and average curtailment costs for the small generator sensitivity study

	PAB	CMCP
Total Constraint Costs (£k)	1,663	1,961
Average Constraint Costs (£/MWh)	129	152

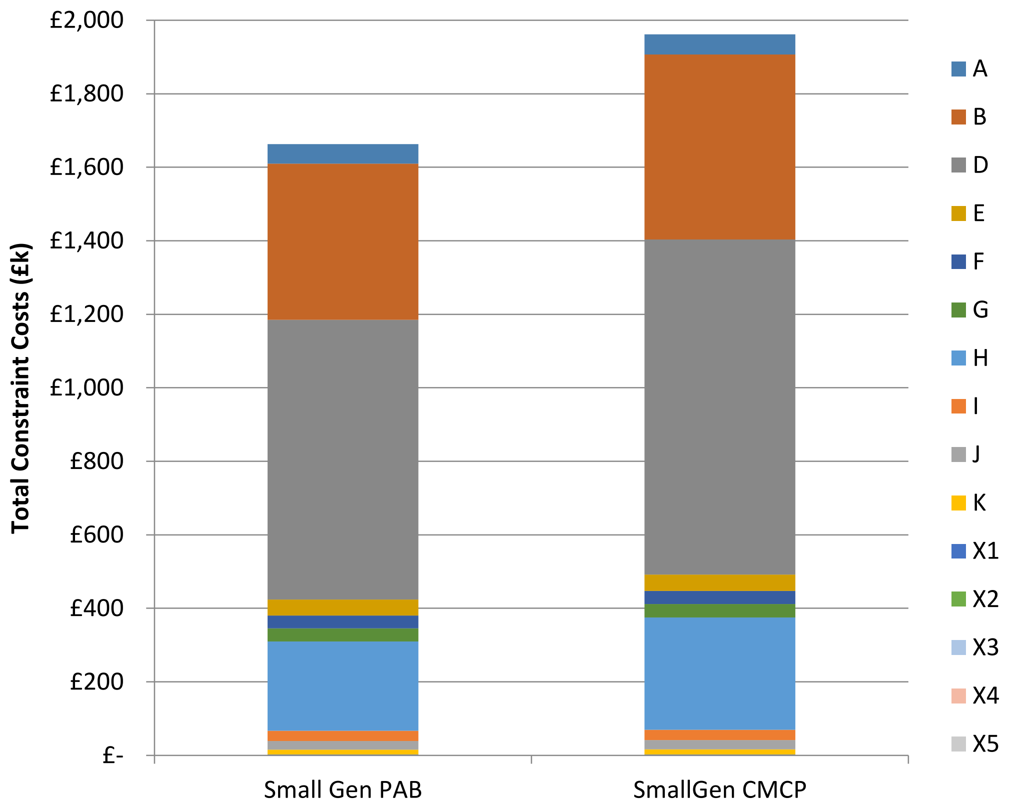

Figure 5-46 Total curtailment costs for market scenarios with additional small generators

Overall, the impact of having an increased number of small generators on the system is to increase the overall cost of curtailment and increase the system price. Smaller generators receive higher subsidy payments which results in higher bid prices submitted for compensation. It should be noted that there are further comparisons to be made with varying generation mix, and comparing dispatchable versus non-dispatchable generation. The behaviour of wind generator would almost certainly be different to that of a PV generator, or a hydro scheme. Dispatchable generation would have greater flexibility in terms of timing and on price.

5.5 Comparison of Market and Non-Market Base Case Models

A summary of all results is given in the figures and tables below. This section will compare the results of the non-market arrangements to the market arrangements using the base case model. These results are for the single GSP constraint example and in all cases there are 3,332 instances of constraint on the network. Table 5-15 gives a summary of results for each arrangement. It is worth noting at this point, that while non-market and market arrangements are compared side by side, compensation is granted to the wind farms under the market arrangements. The energy curtailed is therefore not directly comparable with the curtailment experience under non-market PoA.

Table 5-15 Summary of results for all market and non-market arrangements

	Losses (MWh)		Total Energy Curtailed (MWh)	As % of Uncurtailed Output	As % of net demand/ generation	Average Cost of Curtailment (£/MWh)
	Pre	***Post***				
LIFO	51,991	45,868	9,429	2.43%	4%	£155.36
Pro Rata	51,991	44,651	10,707	2.76%	4%	£139.71
Rota	51,991	44,922	10,422	2.68%	4%	£140.35
Market PAB	51,991	43,729	11,723	3.02%	5%	£123.49
Market CMCP	51,991	43,729	11,723	3.02%	5%	£134.83

Due to certain network topology and branch properties there is a varying degree of losses on the network under different arrangements. This is a result of curtailing different generators in different locations on the network. When generators close to the constraint are curtailed, the losses on the network are high because the large generators located further away from the constraint are allowed to continue generating and therefore contribute to higher network losses. This also has an impact on the total volume of energy curtailed. The total energy curtailed ranges from 9.5GWh under a LIFO arrangement to 11.7GWh under the market arrangements. This equates to between 2.4% and 3% of the total uncurtailed output, or 4-5% of the net demand/generation values. The total energy curtailed is shown in Figure 5-47. This figure demonstrates the share of curtailment between the non-firm generators under the different arrangements. There is a stark contrast in the generators selected for curtailment between the LIFO and the two market arrangements. Under a LIFO arrangement, the generators located at the bottom of the priority stack are smaller generators i.e. Generators I, J and K. When a market arrangement is then applied to the generators, the smaller generators submit higher bid prices as they are entitled to higher subsidy payments under the FIT scheme and therefore the market arrangement will curtail larger generators i.e. Generators B, C and D who are higher up the priority stack under the LIFO arrangement.

The Rota and Pro Rata arrangement give similar results. Both arrangements ensure a relatively even distribution of curtailment across the year. While the Pro Rata arrangement constrains all generators during each constrained period, the Rota arrangement curtails generators using a similar method to LIFO arrangement with the order changing every 24 hours. The distribution of the Rota arrangement curtailment would very much depend on the frequency of the changing of the order and the volume of constraints.

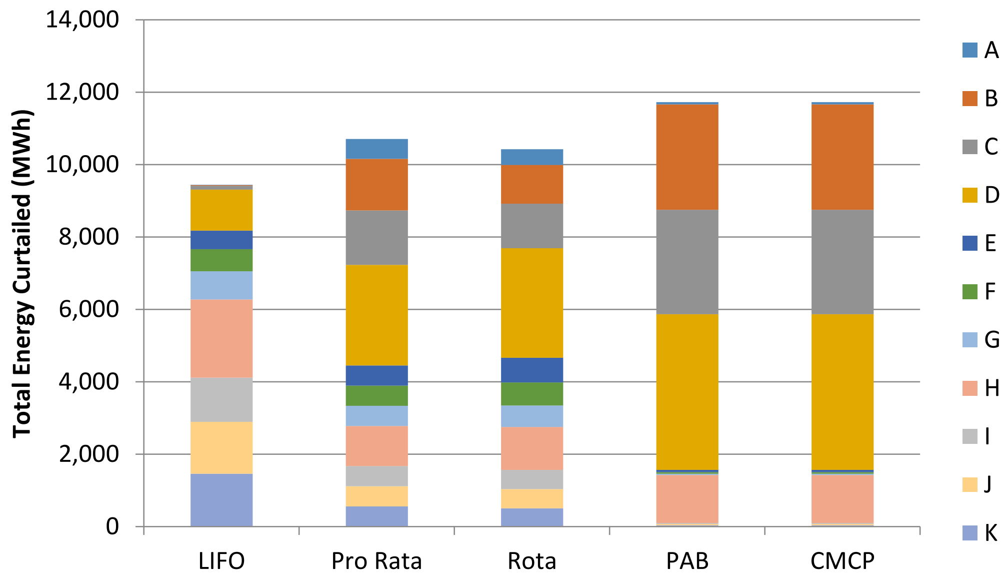

Figure 5-47 Total curtailment levels for all PoA

The average annual capacity factors for each arrangement are shown in Figure 5-48. The uncurtailed capacity factor is 0.51 and the minimum capacity factor is 0.33 under a LIFO arrangement. The capacity factor for the Pro Rata arrangement is 0.44 and the Rota capacity factors range from 0.43 to 0.46. The minimum capacity factor for the market arrangements is 0.37.

The LIFO arrangement results in the most curtailment of all the arrangements as this is the only arrangement where a single generator is always asked to curtail during any constraint event. The other arrangements do not always ask the same generator to curtail first and therefore the minimum capacity factors under these arrangements are higher than the LIFO arrangement.

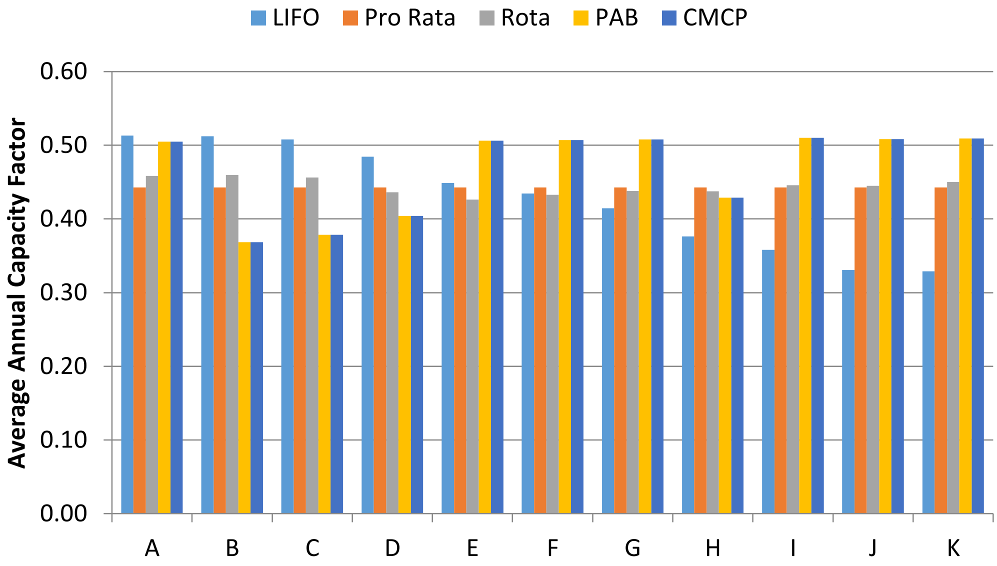

Figure 5-48 Average annual capacity factors for all PoA

Costs for each arrangement are given in Figure 5-49. As discussed previously, the costs shown for the LIFO, Pro Rata and Rota arrangements are based on the initial pre-curtailment costs and are proposed as ‘fixed cost’ compensation for curtailment. The CMCP market arrangement has the largest total cost of curtailment, and therefore the largest average cost of curtailment. This is as a result of paying all generators the system price for curtailment. The PAB market model gives the lowest total cost of curtailment. In this arrangement the larger generators with lower costs are used to clear most constraints. When smaller high costs generators are required to clear constraints, they will be paid their own bid values which happen to be higher than the larger generators. The three ‘fixed price’ options offer similar total curtailment costs for each of the non-market arrangement upon which the pricing is based. The fixed price arrangements fall in-between the PAB and CMCP total curtailment costs. The total costs of a fixed price arrangement could vary dramatically based on the choice of compensation price. An assumption was made in this case of what the estimated lost revenue would be to each generator during periods of constraint, however the network operator may choose to offer a much lower price that those calculated for this example, such as a percentage of the wholesale market price at the time of curtailment.

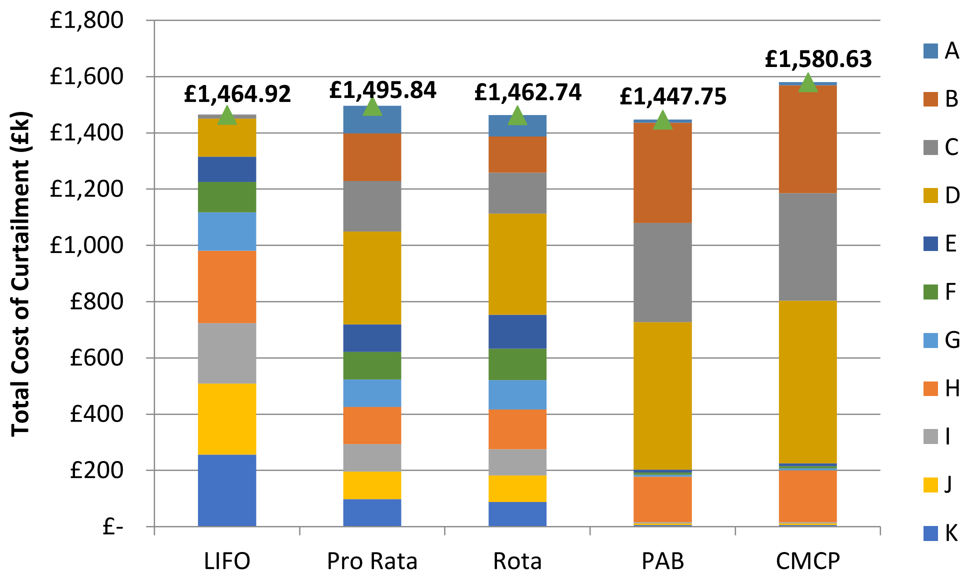

Figure 5-49 Total curtailment costs

5.5.1 Comparison of Market and Non-Market Sensitivity Studies

There are some similarities between elements of the sensitivity analysis studied under market and Non-market arrangements which will allow some comparison to be made. The results of changing the generation mix are summarised in Figure 5-50.

The market results offer an almost opposite result to the LIFO arrangement for the generators at either end of the stack. Generators B, D, and H are used to clear the majority of the constraints under the market arrangement, and the new smaller generators, who have a high FIT tariff and therefore will bid high in to the curtailment market do not suffer any reduction in average annual capacity factor.

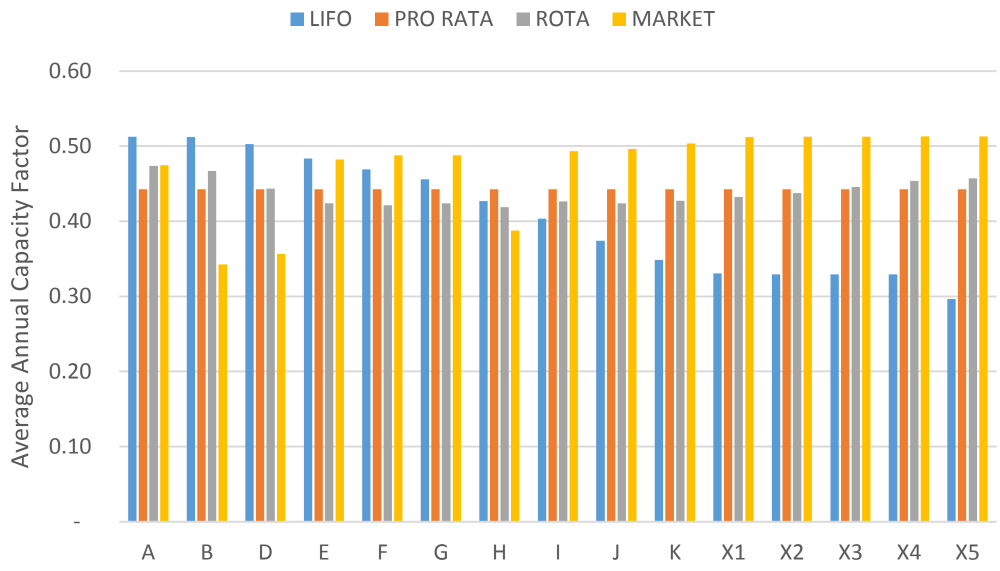

Figure 5-50 Comparison of generator capacity factors when the generation mix is changed, under both market and non-market PoA

The Pro Rata and Rota arrangements offer a similar distribution of capacity factors as experienced in other studies in this chapter. The LIFO arrangement heavily curtails the smaller generators X1 - X5 to clear the constraints throughout the year, with Generators J and K also utilised to clear constraints. These results are similar to those presented in the base case study (See Figure 5-48). This result supports the conclusion that the market arrangement will select large, lower cost generators (based on the cost methodology used in this study) to clear constraints regardless of number of other generators. The impact of including a higher number of smaller sized generators on the LIFO arrangement is to utilise more generators in curtailment activity. The Pro Rata and Rota arrangements provide a balance of curtailment across all generators involved. The important factor in the Pro Rata and Rota arrangements is likely to be total installed capacity rather than number of generators. The total capacity in this study has remained the same, even though the number of generators has increased. In both the base case and the small generator sensitivity study, the average capacity factor for Pro Rata and Rota studies is 0.44. Should the capacity increase, then constraints will increase and therefore, so will curtailment.

The second comparison in this section, will look at the Technical Best study and the market arrangements. The average annual capacity factors are shown in Figure 5-51 below.

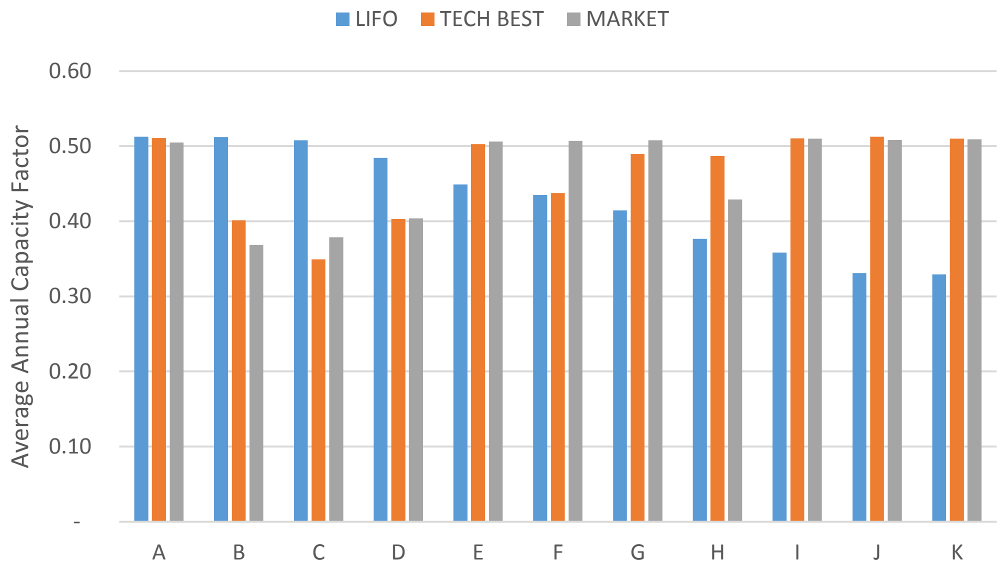

Figure 5-51 Comparison of average annual capacity factor of generators under a LIFO, Technical Best and market arrangement

The technical best study favours the generators located further away from the constraint to minimise the losses on the network. Similarly, the market scenario will select larger generators due to the costs assumed in this study i.e. larger generators have lower FIT and ROC subsidies and therefore submit lower bids in to the curtailment market. The results of the Technical Best and market scenarios are similar. Generators B, C, D and H are used to clear the constraints in both Technical Best and Market arrangements. In this study, the results suggest that the market arrangement also offers the best curtailment scenario for the network operator, as the losses are minimised when compared with other non-market arrangements like LIFO. This conclusion is based on the assumption that generators would always submit true costs to the market – should game playing or un-true bids be submitted, then the cost to the network operator will increase, both in terms of monetary value and network losses. The annual system losses under each base case arrangement are shown in Figure 5-52.

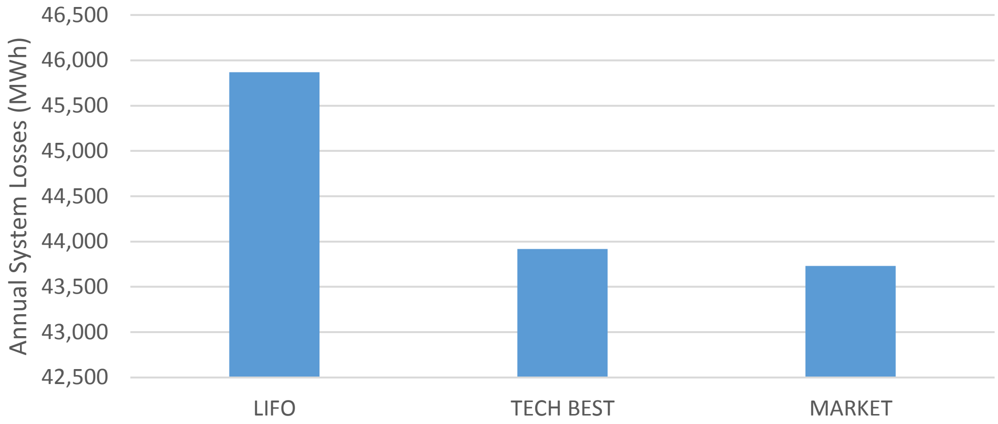

Figure 5-52 Annual system losses under LIFO, Technical Best and market arrangements

5.6 Conclusions

This chapter has demonstrated the impact that different PoA have on non-firm generators connected to a real network case study. The results are similar to those demonstrated by the simple case study example in Chapter Four, which provides support for the modelling methodology used to compare the PoA.

An overview of capacity factors under different PoA is given in Table 5-16 below. The market scenarios give the best overall average capacity factors across the 11 non-firm generators. The LIFO scenario gives the lowest minimum capacity factor because the same generator is always selected to clear the constraint for each occurrence of a constraint on the network. Overall the capacity factors remain in the region of the UK average for onshore wind of 0.26. It should be noted that the case study upon which these results are based has a particularly high wind resource and therefore the capacity factors are likely to be higher than might be experienced in a location in other areas of GB mainland.

Table 5-16 Comparison of Capacity Factors under different PoA studied in this chapter

	A	B	C	D	E	F	G	H	I	J	K	AVG
LIFO	0.51	0.51	0.51	0.48	0.45	0.43	0.41	0.38	0.36	0.33	0.33	**0.43**
Pro Rata	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	**0.44**
Rota	0.46	0.46	0.46	0.44	0.43	0.43	0.44	0.44	0.45	0.45	0.45	**0.44**
PAB	0.51	0.37	0.38	0.40	0.51	0.51	0.51	0.43	0.51	0.51	0.51	**0.47**
CMCP	0.51	0.37	0.38	0.40	0.51	0.51	0.51	0.43	0.51	0.51	0.51	**0.47**

This chapter has highlighted the impact of curtailment arrangements on network losses and therefore the overall curtailment required. While the capacity factors and losses presented in this chapter are particular to this network study, the overarching conclusions will apply to any network applying PoA. The key results from the study of non-market arrangements are as follows:

- Applying a LIFO arrangement will result in smaller capacity factors for those generators are the bottom of the priority stack when compared with arrangements such as Pro Rata and Rota.
- The losses on the network are linked to the size and location of generation in relation to the constraint. Neither LIFO, Pro Rata nor Rota arrangements can guarantee the minimisation of losses on the network.
- A Rota arrangement can give a balance of curtailment across a long time period e.g. upwards of a year, however this will depend on the levels of constraint on the network and the frequency of rotation.
- A Pro Rata arrangement ensures a fair share of the curtailment across all generation connected to the network. The Pro Rata arrangement led to a higher minimum capacity factor when compared with LIFO, leading to the conclusions that the DNO could connect more generation under a Pro Rata arrangement than under a LIFO arrangement while ensuring an economically viable capacity factor.

Comparison of market arrangements has provided an initial study of distribution network markets. The simple method proposed in this thesis gives an indication of behaviours and expected outcomes. The key results are as follows:

- When basing compensation on lost revenue, smaller generators are entitled to higher FIT subsidies and will initially place higher bids when compared with larger generators.
- When basing bids on assumed lost revenue, the bidding behaviour will be divided into groups based on the level of subsidies each generation size is entitled to. Depending on size these groups may be distinctly separate.
- The CMCP arrangement will result in higher overall costs of curtailment in networks where many generators are required to clear the constraint, perhaps during highly constrained periods – as the highest bid price will then be paid to all generation.

The market designs considered in this study are fairly standard designs, and are based on examples from literature. The method used to model the market PoA is relatively simple when compared to more in depth methods such as Agent Based Modelling or Swarm Optimization. The method allows the market PoA to be compared to non-market PoA using the same methodology however the behaviour of the generators, and the costs associated with curtailment is simplified and lacks some depth in terms of simulating realistic bid behaviour.

The average annual capacity factors for each of the sensitivity studies are presented in Table 5-17, Table 5-18 and Table 5-19 below. The results of the sensitivity studies which looked at changing the generation mix have been collated in to a single table (Table 5-19) for ease of comparison.

Table 5-17 Non-market Sensitivity Study #1 and #2 Results

	A	B	C	D	E	F	G	H	I	J	K	AVG
Reverse LIFO	0.34	0.33	0.38	0.44	0.49	0.50	0.50	0.51	0.51	0.51	0.51	0.46
Technical Best	0.51	0.40	0.35	0.40	0.50	0.44	0.49	0.49	0.51	0.51	0.51	0.46

Table 5-18 Market Sensitivity Study Results

		A	B	C	D	E	F	G	H	I	J	K
Precurtailment Levels	I	0.50	0.37	0.39	0.41	0.51	0.51	0.51	0.40	0.51	0.51	0.51
	II	0.50	0.37	0.39	0.40	0.50	0.51	0.51	0.42	0.51	0.51	0.51
	III	0.51	0.36	0.38	0.40	0.50	0.51	0.51	0.43	0.51	0.51	0.51
	IV	0.50	0.36	0.37	0.43	0.51	0.51	0.51	0.39	0.51	0.51	0.51
	V	0.50	0.37	0.38	0.40	0.51	0.50	0.51	0.43	0.51	0.51	0.51
	VI	0.51	0.35	0.36	0.42	0.50	0.50	0.51	0.44	0.51	0.51	0.51
	VII	0.50	0.40	0.41	0.37	0.51	0.51	0.51	0.42	0.51	0.51	0.51
	VIII	0.50	0.38	0.38	0.40	0.51	0.51	0.51	0.43	0.50	0.51	0.51
	IX	0.50	0.41	0.42	0.38	0.51	0.51	0.51	0.40	0.50	0.51	0.51
	X	0.50	0.40	0.40	0.37	0.51	0.51	0.51	0.45	0.51	0.51	0.51
	XI	0.51	0.37	0.38	0.41	0.51	0.51	0.51	0.42	0.50	0.51	0.51
	XII	0.51	0.41	0.42	0.37	0.51	0.51	0.51	0.40	0.50	0.51	0.51
	XIII	0.51	0.41	0.44	0.50	0.51	0.33	0.51	0.33	0.36	0.51	0.44
Random Bid	0-5	0.50	0.38	0.38	0.41	0.51	0.51	0.51	0.41	0.51	0.51	0.51
	0-10	0.51	0.39	0.39	0.40	0.51	0.51	0.51	0.40	0.51	0.51	0.51
Game Playing	Game D	0.46	0.34	0.36	0.51	0.46	0.48	0.48	0.38	0.48	0.49	0.49
	Game DI	0.45	0.35	0.35	0.51	0.51	0.46	0.46	0.38	0.47	0.49	0.49
	Game DEJK	0.45	0.34	0.36	0.51	0.51	0.45	0.46	0.37	0.47	0.51	0.50

Table 5-19 Small Generator sensitivity study results

	A	B	D	E	F	G	H	I	J	K	X1	X2	X3	X4	X5	AVG
LIFO	0.51	0.51	0.50	0.48	0.47	0.46	0.43	0.40	0.37	0.35	0.33	0.33	0.33	0.33	0.30	0.41
PRO RATA	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
ROTA	0.47	0.47	0.44	0.42	0.42	0.42	0.42	0.43	0.42	0.43	0.43	0.44	0.45	0.45	0.46	0.44
MARKET	0.47	0.34	0.36	0.48	0.49	0.49	0.39	0.49	0.50	0.50	0.51	0.51	0.51	0.51	0.51	0.47

The sensitivity studies performed on the case studies have demonstrated the importance of generation mix, namely in terms of capacity factor. For the LIFO arrangement, the position of both large and small generators can have an impact on overall curtailment. Larger generators at the bottom of the priority stack will result in fewer generators being affected by curtailment. The technical best arrangement results in similar outputs to the market studies. The larger generators are used to clear the constraints due to their location on the network and losses sensitivity. This result supports the conclusion that for this network case study, a market scenario will provide a more efficient network operation when compared with a LIFO arrangement.

Sensitivity studies of the market arrangements help to better investigate the impact of market behaviours. The capacity factors from each of the market sensitivity studies is presented in Table 5-18. Changing pre-curtailment profit levels does not have a significant impact on the curtailment behaviour of the market. The average capacity factor across each of the Pre-curtailment studies remains at 0.47. Costs do vary slightly, but are still within a similar range to the initial cost change. This is because only part of the total cost figure is changed in the sensitivity study (i.e. the subsidy level). Should other parts of the cost calculation vary then a wider range of results may be achieved, as demonstrated by the final pre-curtailment level study (study XIII) when the average curtailment value drops to 0.44.

The effect of changing the bid step change (from a set value of 0 or 5, to a random value between 0 and 10) does not have a significant impact on the curtailment behaviour over a period of time. As with the other market studies, the average capacity factor across all non-firm generators remains at 0.47. When gaming occurs in the market i.e. one or more generators submit bids much higher than the assumed pre-curtailment profit level, this has an impact on system costs and in particular, when there are instances of high curtailment and all generation is required to curtail. This affect is seen more significantly in the CMCP market model with larger spikes for the system price.

Changing the generation mix can result in a number of changes to the base case behaviour. The results of the sensitivity studies which assess the impact of a changing generation mix are shown in Table 5-19.

For the non-market scenarios, the additional small generators result in an increase in overall curtailment. The average annual capacity factor across all non-firm generators has now dropped to 0.41 when compared with 0.43 for the base case scenario. The Pro Rata and Rota arrangements provide similar overall curtailment to that experienced in the base case scenario. Both studies give the same average annual capacity factor across all non-firm generators in the sensitivity study of 0.44. In the market studies, the costs and system prices are affected due to the change in bid groups i.e. swapping a large generator with a low pre-curtailment cost for multiple small generators with higher pre-curtailment costs. This changes the behaviour of the system price and the total costs of curtailment.

All of the results presented in this chapter have provided evidence to support alternative PoA to the LIFO arrangement which has been the arrangement selected by most DNOs to date. Pro Rata and Rota arrangements present an option to allow increased capacity factors for those generators who might experience unattractive low capacity factors under a LIFO arrangement.

The market arrangements present an option for distribution curtailment in the future. While the establishment of a market at distribution level would be a lengthy process that would not only require changes to the grid codes but also an investment of time and money from the DNO. The market arrangement may reflect a more accurate description of curtailment and ANM schemes in the future. Fixed price compensation would be a suitable stepping stone between non-market arrangements such as LIFO, towards a full curtailment market at distribution level and this fixed price could be in some way linked to system prices at transmission level in a bid to link activity of generators at distribution level better to wider transmission system operation. A similar model to the fixed price model presented in this chapter was proposed in a recent study for Elexon [169], suggesting that this type of curtailment arrangement could realistically be implemented in industry within the coming decades.

Some of the issues raised here will be followed up in the next chapter which will focus on the commercial aspects associated with different PoA, the costs of these new methods of network management when compared with traditional reinforcement methods and present two business models. These business models will propose a method of cost recovery by network operators who chose to apply a market or non-market curtailment scheme on their networks as part of a Business as Usual process.

6 Commercial Aspects of applying Principles of Access to Business As Usual

6.1 Chapter Summary

This chapter focuses on the commercial aspects of PoA in ANM schemes and discusses the cost of ANM schemes when compared with traditional reinforcements. The results in Chapter Five have demonstrated that there are viable alternatives to LIFO in terms of improving the output of non-firm connected wind farms. The assessment criteria, as defined in Chapter Three, reminds us that there is more to consider with regards to PoA, such as ease of application, grid codes and the flexibility for future network developments.

This chapter begins by discussing how traditional costs of network operation are recovered in GB market. This focuses on an explanation of Transmission and Distribution Network Use of System charging methodologies. By explaining the current methods, it is then possible to identify ways in which network operators may recover the costs of ANM schemes in the future when funding bodies no longer contribute toward all or part of these costs.

The discussion follows on to a further explanation of the Business as Usual (BaU) model for distribution networks. In this case, BaU refers to the standard business model which DNOs will follow to connect a new generator to a network. BaU will soon mean that non-firm connections will be offered as standard alongside firm connections in certain areas of the network, as a result of successful innovation trials. The lessons learned during these trials are currently being transferred in to everyday business practices within the DNO. Business models are proposed based on a method developed by the Oxford Environmental Change

Institute [12]. Visual aids are used to demonstrate the flow of costs and services between stakeholders in an ANM scheme.

The costs of traditional reinforcements are compared to the cost of ANM schemes using a number of examples – all of which were discussed at length in Chapter Two. This discussion highlights the benefits of utilising ANM over traditional reinforcements to enable faster connection of renewables.

The chapter concludes with a discussion regarding the impact of ANM schemes on the wider electricity system.

6.2 Traditional System and Reinforcement Costs

In order to understand the costs associated with traditional network reinforcements, it is first necessary to understand how the network operation and infrastructure is paid for by all users of the electricity system. The total reinforcement costs are composed of Connection Charges and Use of System (UoS) Charges. These charges are applied at both transmission and distribution level, and user costs will depend on the geographical location of the connection. In addition to this, there are also costs for system balancing, known as Balancing Service Use of System (BSUoS) charges. The following subsections describe these costs in order to provide a background to potential methods of recovering the cost of ANM systems.

6.2.1 Transmission Connection and Use of System Charges

Connection charges cover the costs of installing and maintaining each user's connection assets. At transmission level these charges are made up of capital and non-capital components. Capital components will cover the cost of construction, engineering works, interest accumulated during construction, return element and liquidated damages premium where relevant.

The non-capital components include Site Specific Charges (SSF) and Transmission Running Costs (TC) which are calculated as a percentage of the Gross Asset Value (GAV). For the period 2010/11, the percentage value of SSF was 0.52% and TC was equal to 1.45% of capital costs for GB. Connection charges are paid on a monthly basis, and are one-twelfth of the annual charge.

Transmission Network Use of System (TNUoS) charges cover the cost of installing and maintaining the National Electricity Transmission System (NETS). The Maximum Allowed

Revenue (MAR) is set by Ofgem during the pricing control review for each TNO. The application of TNUoS revenue is split between generation and demand, 27% to 73% respectively.

Investment Cost Related Pricing (ICRP) is the model used to determine TNUoS marginal investment prices. This method is explained in detail in Section 6.2 of [104]. ICRP is used to provide an indication to developers of areas where more generation is needed. It assumes that the impact on transmission cost of an extra generator or demand at a particular connection point can be represented by an average reinforcement cost e.g. the marginal cost is estimated in terms of increases or decreases in units of kilometres (km) of transmission system for a 1 MW increase in generation on the system.

The current TNUoS tariff is made up of two separate parts. The first is a locational varying element derived from the DC Load Flow Investment Cost Related Pricing (DCLF ICRP) transport model. DC Load Flow is used as it enables a load flow calculation to be performed on a network with a large number of buses. This reflects the costs of capital investment, operation and maintenance of the transmission system. This' zonal' price is based on the average nodal price in the area at peak time. The cost to the generator is based on maximum power generated or consumed over a year, and the charges are based on the long-run costs of electricity transmission infrastructure and notional reinforcements. The charges do not distinguish between different types of generation. The second part of the TNUoS tariff is a non-locational element related to the delivery of outstanding revenue recovery. The components which come together to make up the TNUoS charge are shown in Figure 6-1. Other charges included in TNUoS are one-off works charges, rental costs, and metering costs.

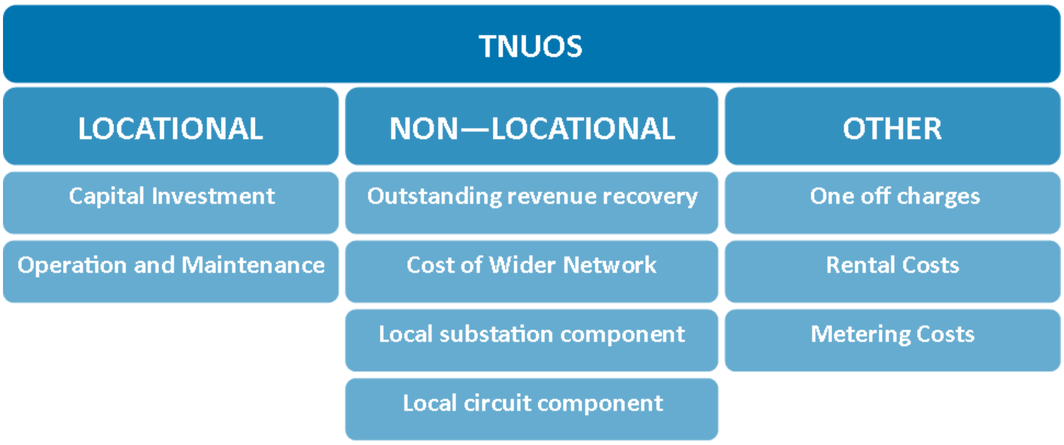

Figure 6-1 TNUoS charging schematic identifying the main components of the charges – locational, non-location and other.

For the period 2014/15, the TNUoS Charges [170] for generation connections in the North of Scotland – where renewable potential is at its greatest is £28/kW which compares to a charge of £10/kW in the North East of England, and a payment of £4/kW in Central London. The cost of connections in the west coast of Scotland, where many islands exist (Skye and Lochalsh region) is greatest, at £34/kW.

A recent review of Island Connections was produced by Xero Energy for the Scottish Government and DECC [171]. The document uses Orkney, Shetland and the Western Island as case study examples. Due to the nature of the connections i.e. lengthy, subsea cables the cost of connection is often difficult to forecast. The Scottish Government has promised a higher strike price for onshore wind projects connected in an Island region (£115/MWh compared with £90/MWh on mainland GB) however these prices are only set until 2018/19. The lengthy nature of building island connections can be in the region of four years, and the lack of long term price certainty is likely to discourage renewable investment where the resource is greatest. This is important as ANM schemes can have a significant impact on Island system as demonstrated by the Orkney and Shetland ANM schemes. It allows connections to be granted quicker when compared with timescales of traditional reinforcement.

6.2.2 Distribution Network Use of System (DNUoS) and Connection Charges

Each DNO has its own individual connection charging methodology, but they all follow a standard outline. SP Energy Networks has been used as a reference case [172] in this section to demonstrate the typical charges imposed at distribution level.

The Connection Charge can be split into three categories:

- Costs for providing the connection paid by connectees
- Costs for providing the connection split between DNO and connectees
- Costs to be paid by connectees in respect of work that has previously been constructed or are committed and are used to provide the connection

Costs paid by the connectee include shallow connection costs e.g. any additional assets which are required in order for a generator to connect into the network. If there is any reinforcement required on the shared distribution network, the cost of this reinforcements split between the DNO and the connectee. Reinforcement costs in excess of £200/kW will be charged to the connectee in full.

Costs which are shared between the connectee and DNO are calculated using Cost Apportionment Factors (CAFs). There are two variations of CAFs calculations, Security CAF and Fault Level CAF. The choice depends on the need for reinforcement.

Costs paid in full by the DNO include the costs of network reinforcements which are at a voltage level higher than the point of connection.

Similar to connection charges, each DNO has its own Use of System tariffs which follows the Common Distribution Charging Methodology. Tables which outline the individual DNUoS tariffs are available from respective DNO websites. An example of Scottish Power DNUoS charging table is shown in Figure 6-2. These tables include the list of all tariffs available for connection to the DNO and the charges applicable under these tariffs. The charges are split into two main categories – Non Half-Hourly (NHH) metered and Half Hourly (HH) metered users.

SP Distribution - Effective from 1 April 2014 - Final LV and HV charges

Time Bands for Half Hourly Metered Properties			
Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday (Including Bank Holidays) All Year	16.30 - 19.30		
Monday to Friday (Including Bank Holidays) All Year		08.00 - 16.30 19.30 - 22.30	
Monday to Friday (Including Bank Holidays) All Year			00.00 - 08.00 22.30 - 00.00
Saturday and Sunday All Year		16.00 - 20.00	00.00 - 16.00 20.00 - 00.00
Notes	All the above times are in UK Clock time		

Time Bands for Half Hourly Unmetered Properties			
	Black Time Band	Yellow Time Band	Green Time Band
Monday to Friday (Including Bank Holidays) June to August Inclusive		08.00 - 22.30	00.00 - 08.00 22.30 - 00.00
Monday to Friday (Including Bank Holidays) November to February Inclusive	16.30 - 19.30	08.00 - 16.30 19.30 - 22.30	00.00 - 08.00 22.30 - 00.00
Monday to Friday (Including Bank Holidays) March to May, and September to October, Inclusive		08.00 - 22.30	00.00 - 08.00 22.30 - 00.00
Saturday and Sunday		16.00 - 20.00	00.00 - 16.00 20.00 - 00.00
All other times			
Notes	All the above times are in UK Clock time		

	Open LLFCs	PCs	Unit rate 1 p/kWh (red/black)	Unit rate 2 p/kWh (amber/yellow)	Unit rate 3 p/kWh (green)	Fixed charge p/MPAN/day	Capacity charge p/kVA/day	Reactive power charge p/kVArh	Excess capacity charge p/kVA/day	Closed LLFCs
Domestic Unrestricted	100, 101, 110, 111, 160, 161	1	2.283			5.04				
Domestic Two Rate	114, 115, 118, 119, 120, 121, 162, 163	2	2.923	0.331		5.04				
Domestic Off Peak (related MPAN)	112, 113, 116, 117, 132, 133, 136, 137, 164, 165, 166	2	0.235							130, 134, 135
Small Non Domestic Unrestricted	201, 204	3	1.893			6.43				200, 202, 203, 205
Small Non Domestic Two Rate	221, 224, 260	3&4	2.615	0.355		6.43				220, 222
Small Non Domestic Off Peak (related MPAN)	225, 240, 241, 301, 302	4	0.775							223, 242, 243, 244, 245, 246
LV Medium Non-Domestic	400, 402	5-8	1.677	0.259		30.80				
LV Sub Medium Non-Domestic	404	5-8	1.252	0.173		0.00				
LV HH Metered	500, 504	0	9.220	0.746	0.136	25.34	2.42	0.267	2.42	

Overview | Annex 1 LV and HV charges | Annex 2 EHV charges | Annex 2a Import | Annex 2b Export | Annex 3 Preserved charges | Annex 4 LDNO charges | Anr ...

Figure 6-2 Example of Distribution Charging Methodology – Scottish Power Distribution [173]

The charges for NHH are applied on the basis of Line Loss Factor Classes (LLFCs) and the units of power consumed within the time periods specified. The charges can be split into the following components:

- A fixed charge (pence/MPAN/day) – there is only one fixed charged applied to each Metering Point Administration Number (MPAN)
- Unit charges (p/kWh) based on active consumption or production provided through Settlement. More than one kWh charge may be applied

Charges for HH metered users is composed of the following components:

- Fixed charge (p/MPAN/day)
- Capacity charge (p/kVA/day) for an agreed Maximum Import/Export Capacity
- Excess capacity charge (p/kVA/day) if Maximum Import or Export is exceeded
- Unit charges (p/kWh) for the transport of electricity over the system
- Excess reactive power charge (p/kVAr/h) – applies when reactive power exceeds 33% of total active power (equivalent of 0.95 power factor)

6.2.3 Balancing Service Use of System (BSUoS)

The principle of BSUoS charging is to allow the National Grid to recover the costs incurred in balancing the transmission system i.e. ensuring safe and secure supply to end users. National Grid is incentivised by Ofgem to accrue these balancing services in a cost effective manner. Figure 6-3 shows the external system operation costs since 2006. In recent years the cost of balancing the system has increased sharply. This can be explained by the increase in renewable generation and the work being carried out to upgrade the transmission infrastructure. The constraints caused by upgrade work will lead to an increase in balancing services required.

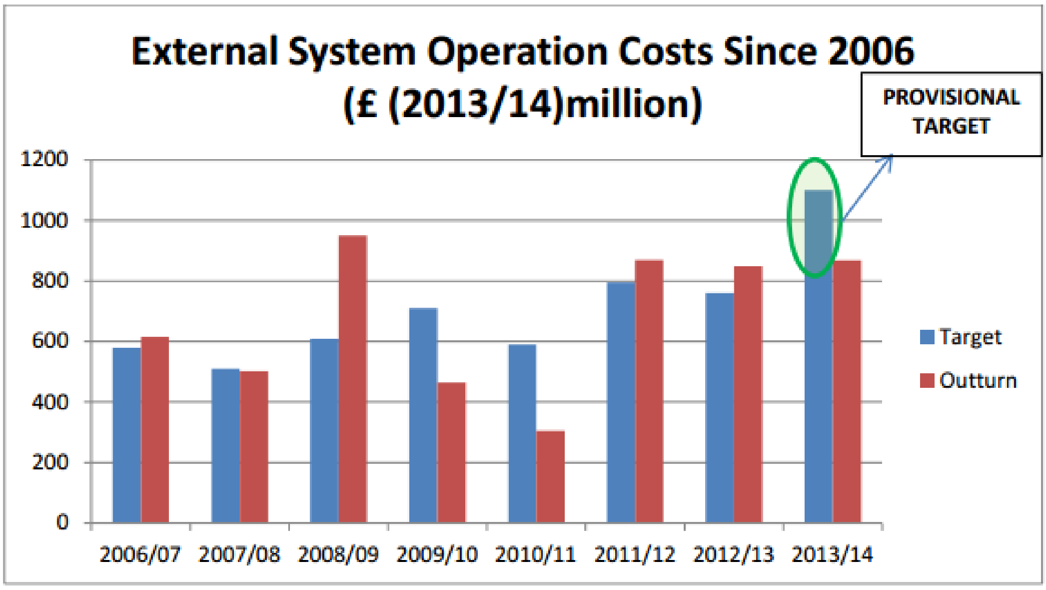

Figure 6-3 External system operation costs from 2006 to 2014 [174]

BSUoS charges include the following costs:

- The total costs of the balancing mechanism (BM)
- Total balancing services contract costs
- Payments/receipts from National Grid incentive schemes
- Internal costs of operating the system
- Costs associated with contracting and developing balancing services

The Daily BSUoS charge for each party consists of the sum of BM Unit Metered Volume for all BM Units owned and summed over all the settlement periods on a particular settlement day. Transmission losses are taken into account in this calculation. The Total BSUoS Charge applicable for each settlement period is composed of two parts: an External and Internal Charge.

The external charge is calculated by taking the cash flow and variable costs for each settlement period and is allocated on a per MWh basis for each settlement period in a day. The external charge also considers the external incentive payment which is calculated as the difference between the new total incentive payment and the incentive payment that has been made to date for previous days.

The internal charge for each settlement period is calculated by taking the incentives and non-incentivised system operator internal costs for each settlement day allocated on a MWh basis across each settlement period in a day. Similarly to the external charge, an internal incentive payment is included in this calculation. There is further inclusion of a daily cost of Manifest errors and Special Provisions which accounts for any compensation which National Grid must pay to balancing service participants.

6.2.4 Consumer Energy Bill

In order to explain how the network and system charges described above are transferred to a domestic energy customer, a breakdown of a standard electricity bill is shown in Figure 6-4. The network charges discussed in Section 6.2 equates to around one fifth of a domestic energy customers energy bill. All decisions network owners make regarding transmission upgrades and reinforcements must be justified to Ofgem to ensure consumers get a fair deal.

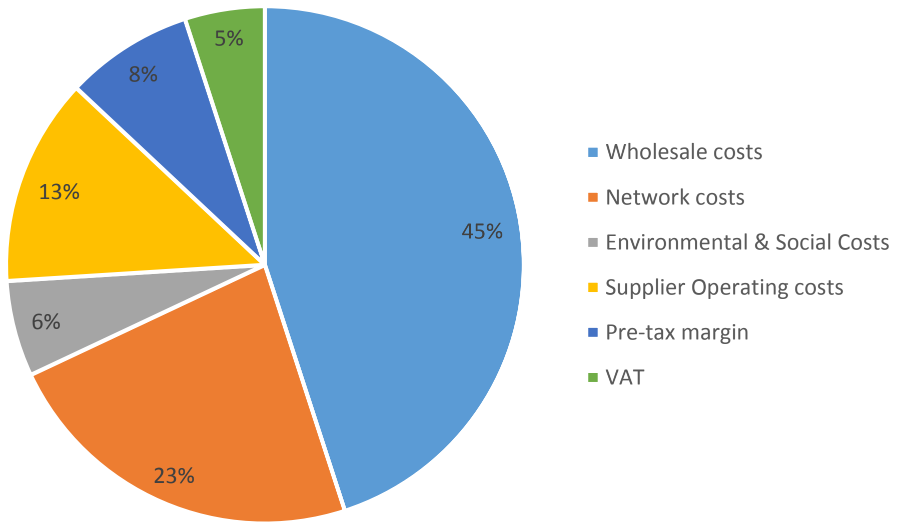

Figure 6-4 Breakdown of customer energy bill [175]

Energy suppliers are responsible for meeting the demand of domestic consumers by purchasing electricity on the energy market. In doing so, energy suppliers make use of the transmission and distribution network in order to 'transport' this electricity to customers homes and are therefore required to pay 'Use of System' charging.

The consumer pays the energy supplier e.g. N-Power, Scottish Power, E-On etc. according to a tariff agreed between the consumer and energy supplier. The tariff may include pass-through costs, e.g. a cost that is charged to the energy supplier, but is then 'passed through' directly to the consumer. The elements in a typical consumer electricity bill are explained below. Transmission and distribution charging has already been explained in previous sections of this chapter, this section focuses on the calculation of the remaining charges for domestic customers.

6.2.4.1 Half Hourly and Non Half Hourly Customers

Consumers of electricity are split into two categories: half-hourly metered (HH) and non-half-hourly metered (NHH). Customers whose peak demand is 100kW or greater in any single half hour period are obliged to have a HH meter, which takes a meter reading every 30 minutes. This is typically industrial customers.

Domestic energy customers typically have NHH meters, although the option to install a HH meter is possible. Under a standard NHH customer model, a representative from the supply company is required to visit each property to read the meter and determine the energy use. The energy bill is then an estimate of energy use. Currently, the UK Government is overseeing a UK wide roll-out of Smart Meters [176]. This will improve billing accuracy for domestic energy customers when compared with typically NHH customers. Giving customers the power to monitor their own energy use, and be aware of the price of energy at certain times of the day. The roll out is scheduled to take place between 2015 and 2020.

The TNUoS charges for HH customers is their demand during the triad periods multiplied by the tariff for their zone. The Triad refers to three half-hour settlement periods with the highest system demand between November and February separated by at least 10 days. TNUoS charges levied on NHH metered customers is the sum of their total consumption between 16:00 and 19:00 every day over a year multiplied by the relevant tariff linked to the geographical zone they are connected in. The following charges make up the remainder of the customer bill:

- A Climate Change Levy is a p/kWh tax on certain electricity use. Exempt suppliers include domestic supplies and suppliers using less than the De Minimis threshold of 1,000 kWh / month
- Settlement charge
- A data collection charge is paid to the Data Collector for determining the energy consumption of the supply
- A meter operation charge - The fee paid to the meter operator for installing and maintaining the meter

- VAT is payable at the standard rate unless the supply meets certain conditions (e.g. domestic supplies, or supplies that use less than 1000 kWh per month) in which case they are charged at the reduced rate

6.2.4.2 Retail Market Review

At the time of writing, Energy Suppliers are undergoing a retail market review by Ofgem [177]. Due to rising energy prices in recent years, and the domination of the energy market by 'The Big Six' energy suppliers it has been requested that a formal review of the energy market is carried out in order to determine if charges for energy customers are fair. Solutions already implemented include the removal of complex tariffs from the market and an obligation for suppliers to ensure customers are on the lowest priced tariff to suit their needs. This review is currently on going.

6.3 Summary of Charges within the Electricity Market

The schematic in Figure 6-5 illustrates how these charges are organised within the electricity market and how the flow of money and electricity is passed between different stakeholders. A description to accompany the diagram is given below.

1. Generators pay the transmission network owner in exchange for connection to the network. Generators can then transfer energy to the transmission network. Generators who wish to connect at distribution level can apply directly to the DNO for connection.
2. The DNO pays the transmission network UoS charges in exchange for transferring energy from the generators via the transmission system and into the distribution network.
3. Energy suppliers pay TNUoS and DNUoS for the transport of energy through both network systems.
4. Energy is then passed on to Domestic and Industrial customers who pay the energy supplier for this. This payment is made up of the price of the energy, taxes, TNUoS and DNUoS changes, the cost of balancing the system.
5. The system operator balances the system and can request help from generators at any time.

6. Generators can also enter in to 'bilateral contracts' with energy suppliers where a long term agreement is made. A price is set in advance of delivery for a total volume of energy. This is how the majority of energy on the system is contracted.

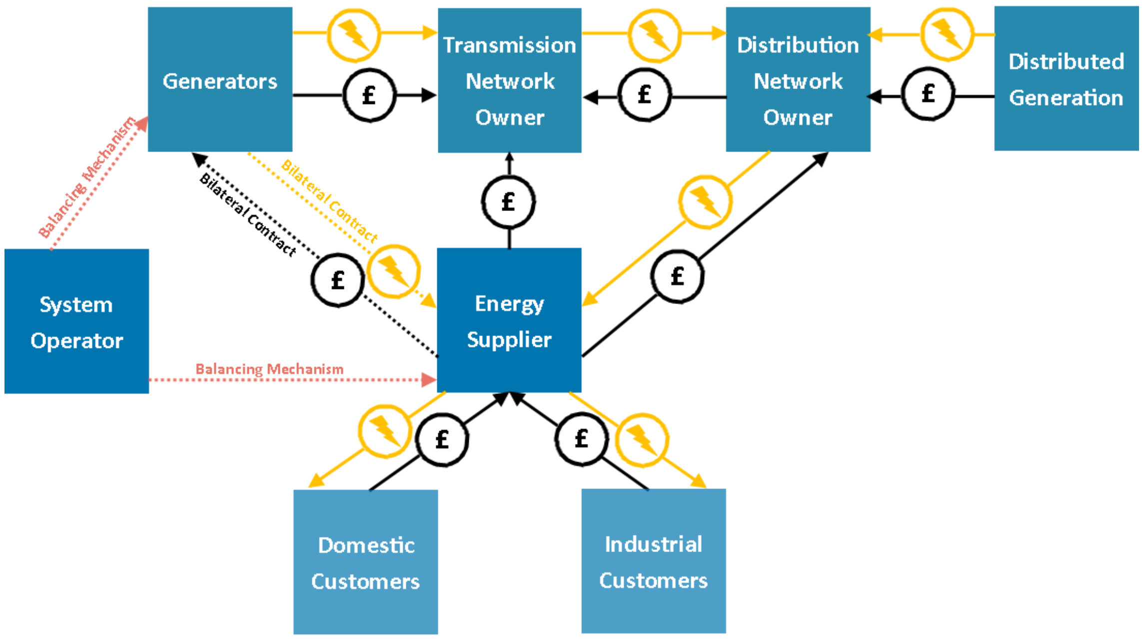

Figure 6-5 Schematic diagram of electricity industry stakeholders

6.4 The Cost of ANM Schemes vs Traditional Reinforcements

Section 6.2 has illustrated the method of cost recovery for the traditional means of maintaining and upgrading the transmission and distribution infrastructure, and also how these costs are passed on to users of the system. ANM presents a new method of not only operating the distribution network, but also a new set of costs and maintenance routines. This section compares the costs of traditional reinforcements (i.e. increase existing capacity of transmission lines, creating new transmission lines etc.) against the cost of ANM schemes.

Similar to traditional reinforcements, when installing an ANM scheme, the DNO may be required to invest in additional network management equipment. This may include:

- Communications
- Controllers - for individual users of the network – both generator and demand, and at domestic and commercial level
- Additional Operation and Maintenance costs
- Staff – either additional staff, or training existing staff

Using some of the case studies presented in Chapter Two, the funding received for the development and installation of the ANM schemes in those cases are presented below in comparison with the traditional reinforcements. The DNO must justify any expenditure to the regulator as the costs of reinforcements are passed on to customers. The generators will benefit from the lower shallow charges for connections, and all users of the network should benefit from lower charges for deeper reinforcement costs. A summary of the funding granted for ANM schemes is given in Table 6-1.

Table 6-1 Summary of ANM vs traditional reinforcement costs

	Additional Wind	ANM Funding	Traditional Reinforcement costs
Orkney	25 MW	£500k	£30million
Shetland NINES	10-15 MW*	£33.54million	£300million
FPP	24.2 MW	£6.7million	£15.3million
ARC		£3 million	£20 million

*The NINES scheme also includes a battery, a district heating system and domestic demand side management scheme.

The funding of the Orkney ANM scheme was £500k [80] compared with the £30 million cost of an additional subsea cable to increase network capacity. Orkney is already connected to the mainland GB grid via two subsea cables; however the firm capacity of generation on the network had already been reached. With the creation of an ANM scheme, an additional 25 MW of wind was connected. In 2012, the network reached maximum capacity and SHEPD issued a moratorium on the connection of renewables to the distribution network. At the time of writing, a consultation is in progress as to whether to increase the capacity of the network [178], with three options proposed:

1. A new transmission connection at the cost of £300 million
2. A new distribution connection at an estimated cost of £30 million
3. Maintaining the status quo until the increase in more developed renewable technologies such as onshore wind increases significantly enough to justify the expenditure of options 1 or 2

The funding of the NINES scheme in Shetland is approximately £33.5 million. This funding includes the ANM scheme, a large battery, a district heating system and a domestic demand side management scheme. All of these proposed solutions will work together to ensure reduced reliance on conventional generation and increased facilitation of wind generation connections. The alternative solution is to install a £300 million subsea cable to connect Shetland to mainland GB network. The installation of the subsea cable is currently subject to discussion [179]. Regardless of the outcome, there is still the need for Shetland to be able to operate as an islanded network, as a failure in the subsea cable could lead to lengthy outages.

The cost of the FPP ANM scheme is approx. £6.7 million (total funding awarded by Ofgem) which compares to reinforcement costs i.e. upgrading the transformer, of £15.3 million [90]. The difference in individual generator connection costs is shown in Table 6-2.

The connection cost savings are in the region of 50%-90%. The high traditional reinforcement costs are a result of generators having to pay to connect to a grid supply point at a location further away from the preferred GSP which is currently at capacity.

Table 6-2 Table of FPP connection costs vs. typical connection costs [10]

Project	Capacity	Typical Connection Offer	FPP Budget Estimate	Savings (%)
Gen A	5 MW	£1.2 m	£570 k	53%
Gen B	0.5 MW	£1.9 m	£400 k	79%
Gen C	10 MW	£4.8 m	£500 k	90%
Gen D	7.2 MW	£3.5 m	£700 k	80%
Gen E	2.5 MW	£1.9 m	£170 k	91%
Gen F	1 MW	£2 m	£300 k	85%

The ARC project is estimated to cost £3 million for the installation of the ANM scheme and new connections for renewables will be granted by March 2015. An alternative option is £20 million of upgrades to the GSP causing constraints, with delays to connections until 2020 [180]. There is no current information available regarding the capacity that the ANM solutions will enable. Without ANM or other alternatives, there is no more available capacity on the ARC networks for new generators to connect. Stakeholder engagement as part of the consultation suggested that ANM should only be used as a short term solution and that the necessary upgrades to the network infrastructure should be carried out in future to assure firm capacity [181]. This raises the question as to how the firm capacity upgrades should be paid for and will be discussed later in this chapter.

It is clear from the values presented in Table 6-1 and Table 6-2 that ANM offers a solution to facilitating large volumes of renewable connections to distribution networks. The costs are significantly lower than investing in traditional reinforcement strategies and ANM schemes also take a shorter time to install and implement on the network. However there is an argument to suggest that ANM solutions are short term and that network owners will eventually invest in traditional reinforcement, as demonstrated by the Orkney example.

During a meeting of the Smart Grid Forum in August 2014, the minutes of the meeting [182] note that a framework was presented for DNOs to assess the costs of network reinforcement and identify alternative actions they could take. The presentation was with reference to energy efficiency measures and it was suggested that DNOs should make reinforcement choices based on the implications for customers in fuel poverty. Under current regulatory framework, DNOs are already incentivised to minimise reinforcement costs and therefore use alternative solutions, however the use of the framework could help DNOs to make the best choices for consumers. Further information regarding this framework was due September 2014, however at the time of writing there was no update as to the progress of this framework.

While it is clear from these examples that the cost of ANM schemes are lower than traditional reinforcements, it is not clear through which of the typical cost recovery mechanisms the ANM scheme is paid for. Generators pay for connections to the network as sole use assets. Reinforcements are calculated on a per generator basis and the costs shared across all network users. This following section will discuss how it may be possible to recover the cost of an ANM scheme which essentially requires the network operator to pay for the reinforcement before it has connected any generators. Two business models are proposed as to how DNOs might recover the cost of ANM schemes in the UK.

6.5 Business as Usual

The success of ANM schemes in recent years has provided a drive for DNOs to offer ANM solutions alongside traditional connection agreements.

As discussed in Section 6.4 the capital costs of ANM schemes have been shown to be lower than traditional network reinforcements. Currently, the costs of network reinforcements are recovered through a combination of connection and use of system charging depending on the voltage level of the connection [183]. To date, the cost of ANM schemes have received funding through network research and development funds, and schemes such as Registered Power Zone (RPZ) [184] and LCNF [185] as discussed in Chapter Two. As ANM schemes become a BaU option, a mechanism by which the network can recover the costs of installing, operating and maintaining an ANM system must be established. This section will outline two potential business models for the BaU deployment of ANM schemes.

SSEPD is the first company to propose ANM as BaU and has created a number of use cases and business process which describe the way in which the ANM system is both operated and maintained [186]. SSEPD propose that an annual subscription fee is paid by each non-firm generator to cover the costs of installing and maintaining an ANM system. This is paid to the DNO when the generator connects, and then each year on the anniversary of the connection. While the DNO pays for the majority of the ANM equipment, the non-firm generator is responsible for installing the communications link between the ANM system and the generation site.

One way of demonstrating a complex business model is by using a visual aid. SSEPD have done this through the use of 'Enterprise Architecture Models' which uses the Business Process Modelling Notation [187], an example of which is shown in Figure 6-6 below. The model outlines the main process in each stage of the ANM business process and how these processes are carried out with the main stakeholders.

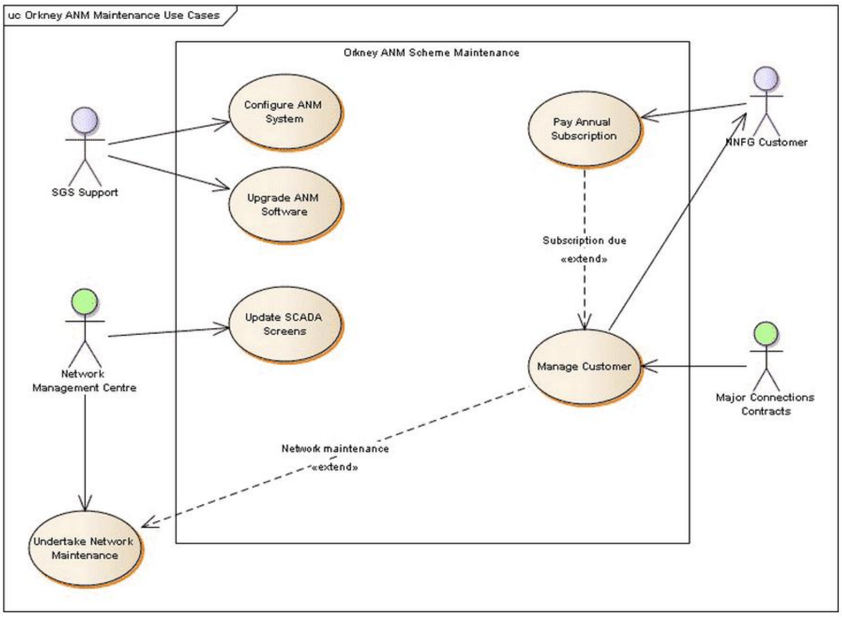

Figure 6-6 SSEPD diagram explaining Orkney ANM maintenance use cases [186]

Another form of visually representing business models was developed by The Environmental Change Institute [12]. The models demonstrate the flow of money, services, assets and information between actors in the business model, as well as highlight complexities and critical relationships. This format has been used in this thesis to create two business models, one for a market PoA and one for a non-market PoA. These models propose how costs of ANM might be recovered as well as compare an ANM system to a standard distribution network that is not using 'smart' technologies or alternative management techniques. The models suggest one method of recovering the costs of an ANM scheme; however, there are many variations which could be determined as best practice for different DNO and ANM schemes. The models are compared to a base case scenario. In this base case scenario, there are no smart technologies in use and domestic electricity users obtain electricity via vertically-integrated suppliers and large decentralised generators. A version of this model and the related discussion is published in [188].

The legend for the business models is presented in Figure 6-7. The top half of the legend contains diagrams representing actors or stakeholders in the ANM process. Most of these actors are self-explanatory. The wind generator actor could be used to describe all renewable generation, however in this case the focus is on the curtailment of wind in particular. The 'outside of system' actor represents those who are involved outside of the ANM/Distribution system. The ANM operator refers to the body in charge of operating and installing the ANM system. This could be split in to two separate entities but for simplification is left as a single stakeholder in this case.

The bottom half of the legend is split in to two parts. The diagrams on the left are types of flow on the graph i.e. whether electricity, a physical object, money or non-monetary object is passed between ANM actors. The diagrams on the right are used to further describe the flows of goods are services. Recurring events are objects which are transferred more than once, i.e. a recurring payment such as a monthly or annual fee. In contrast, some objects are 'one-time' events i.e. a single lump sum payment. The plus and minus signs indicate whether the object is more than or less than the base case scenario. For example, ANM allows a great volume of renewable electricity to flow when compared with a standard distribution network with no ANM technologies installed. This is because the ANM has facilitated the connection of more renewable generation on the distribution network.

Finally, the shaded rectangles provide a comparison between flows in each strand of processes. If there are two or three flows of electricity side by side, these icons are used to rank them in order or magnitude.

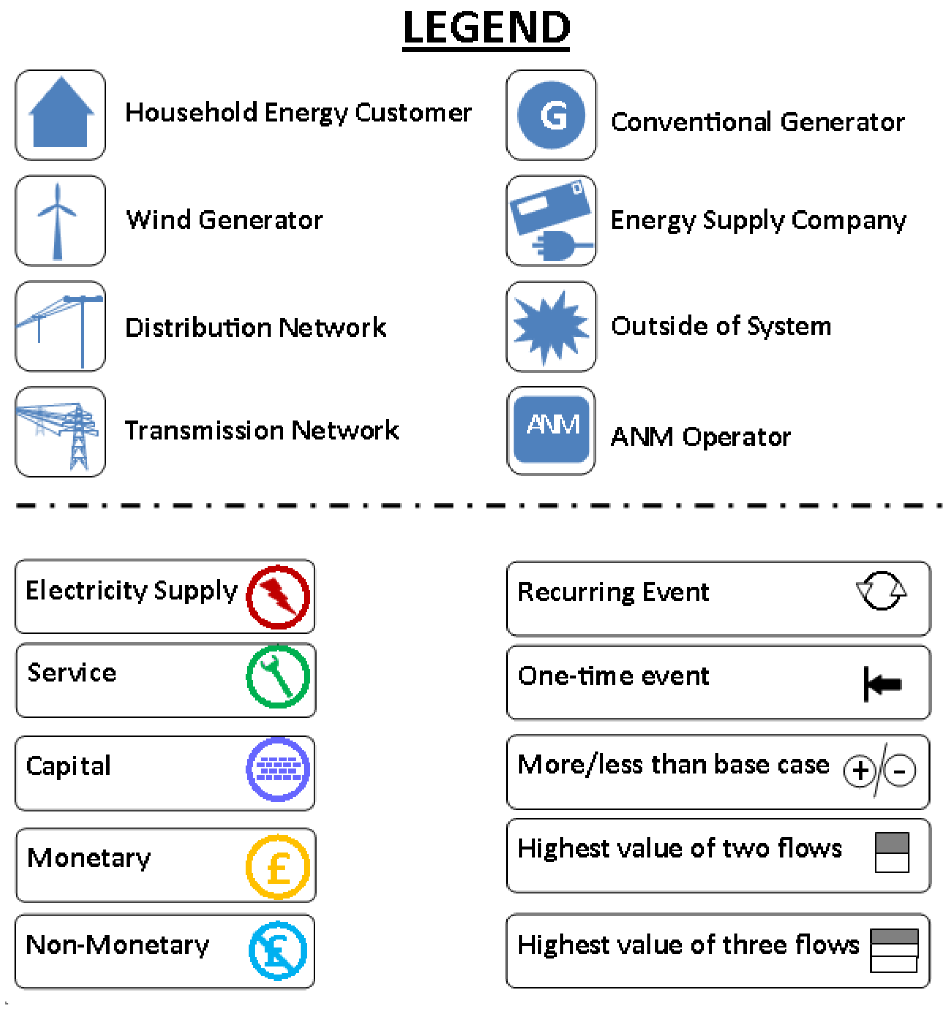

Figure 6-7 Legend for business models in Figure 6-8 and Figure 6-10

6.5.1 Business model proposed for a Non-Market PoA

The model shown in Figure 6-8 demonstrates the flow of money and services between key stakeholders in an ANM scheme applying a non-market PoA. It proposes that the cost of ANM management and installation of shared network equipment be recovered through Distribution Network Use of System (DNUoS) charges, similar to the way in which network reinforcements are recovered. This is different from the method used by SSEPD, which will cover the cost of ANM via an 'ANM Fee' for the current ANM schemes.

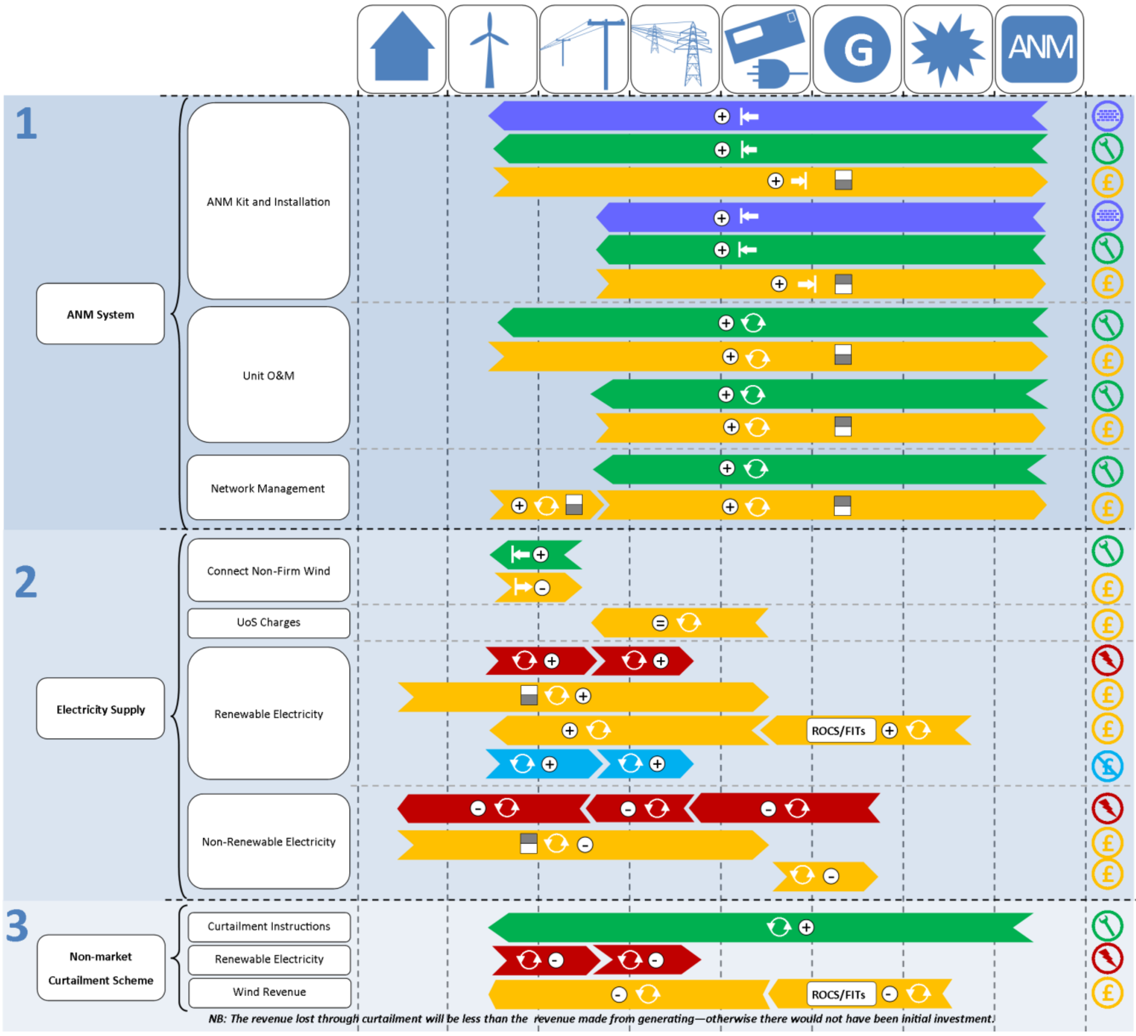

Figure 6-8 Business model of ANM Scheme operating non-market PoA (Based on models developed by SuperGen HiDEF Distributed Energy Modelling project [12]

There are three sections in each business model, referred to as 'Strands'. Each Strand represents a different part of business processes, and makes it easier to read the diagram.

Strand One of Figure 6-8 encapsulates the installation of the ANM system. The ANM equipment is provided and installed by the ANM operator. They are also responsible for the operation and maintenance (O&M) of the ANM tools. The generator pays for the equipment installed locally, and the DNO pays for any centralised ANM equipment. The payment made by the non-firm generator for the connection to the network and ANM equipment is lower than the connection charge under a traditional arrangement, which would include both shallow and a proportion of deep connection upgrade work.

Strand Two highlights the changes in electricity supply and how this is passed on to customers through DNUoS charging. The installation of an ANM scheme on the network allows more generation to connect to the network under a non-firm connection. Use of System charges are still passed on to the DNO via the energy supplier.

For example, the following steps will explain the activity in the 'Electricity Supply' of renewable electricity in Strand Two.

- There is an increase in the electricity produced by the wind generator, which is passed to the DNO, and then on to the transmission network.
- This leads to the energy user paying the supplier for the renewable energy.
- ROCs or FIT subsidies are passed to the supplier, and then on to the generator.
- Finally, this results in reputational benefits for the DNO and TNO who can report on carbon reduction for the network.

The volume of renewable electricity on the system increases, more of the customer's energy bill goes to paying for the renewables and there is more subsidies paid to renewables via the energy supplier. The social repercussions are also noted – in keeping to the UK carbon reduction targets, DNOs are keen to promote that they support renewable energy schemes. For example, a screen shot of SSEPD website in Figure 6-9, where reference is made to the number of renewable connections made by the DNO [189]

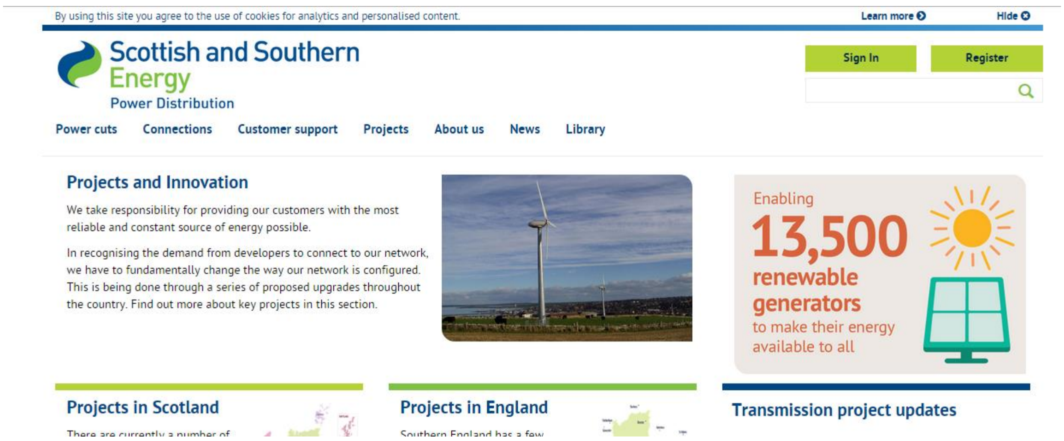

Figure 6-9 SSEPD Project and Innovation website, showcasing the number of renewable generators connected [189]

The volume of non-renewable electricity is reduced because it has been replaced by renewable sources. This reduces the amount consumers spend on non-renewable electricity, and the profits non-renewable generators receive.

Finally, Strand Three deals with the curtailment of non-firm generators. This is managed by the ANM Operator. As a result of curtailment, there is a reduction in export of renewable energy, and therefore a reduction in revenue and profit made by generators from ROCs or FITs when compared with firm connected generation.

In summary, the BaU process for a DNO running an ANM scheme with a non-market PoA is as follows

1. ANM equipment is installed and maintained by the ANM operator. The cost of any equipment is paid for by the non-firm generator and the DNO to the ANM operator, depending on where the equipment is installed. The architecture of the ANM system might lead to different shares of the equipment costs between the DNO and generator.
2. ANM allows more renewable generation on the network, improving the customer service delivery and reputation of the DNO, not to mention meeting the DNO license conditions relating to offering least cost connections to customers. Customers now contribute a larger percentage of their energy bill towards renewables than when compared with conventional generation. Use of System charges are similar to the standard model, and are now used to cover the cost of ANM as opposed to the cost of traditional reinforcements. Generators contribute towards to cost of ANM through UoS charges, however the connection charge is lower to reflect the 'non-firm' aspect.
3. A non-market PoA is applied and the ANM operator issues to curtailment instructions to the non-firm generator. The generator is then required to reduce output which means a reduction in income.

6.5.2 Business Model Proposed for a Market PoA

Similar to Figure 6-8, the business model proposed in Figure 6-10 demonstrates the flow of money and services between stakeholders in an ANM scheme applying a market PoA e.g. where generators submit bids and are curtailed based on the value of the submitted bid. The first two strands of Figure 6-10 match those of Figure 6-8 therefore the same logic and processes apply.

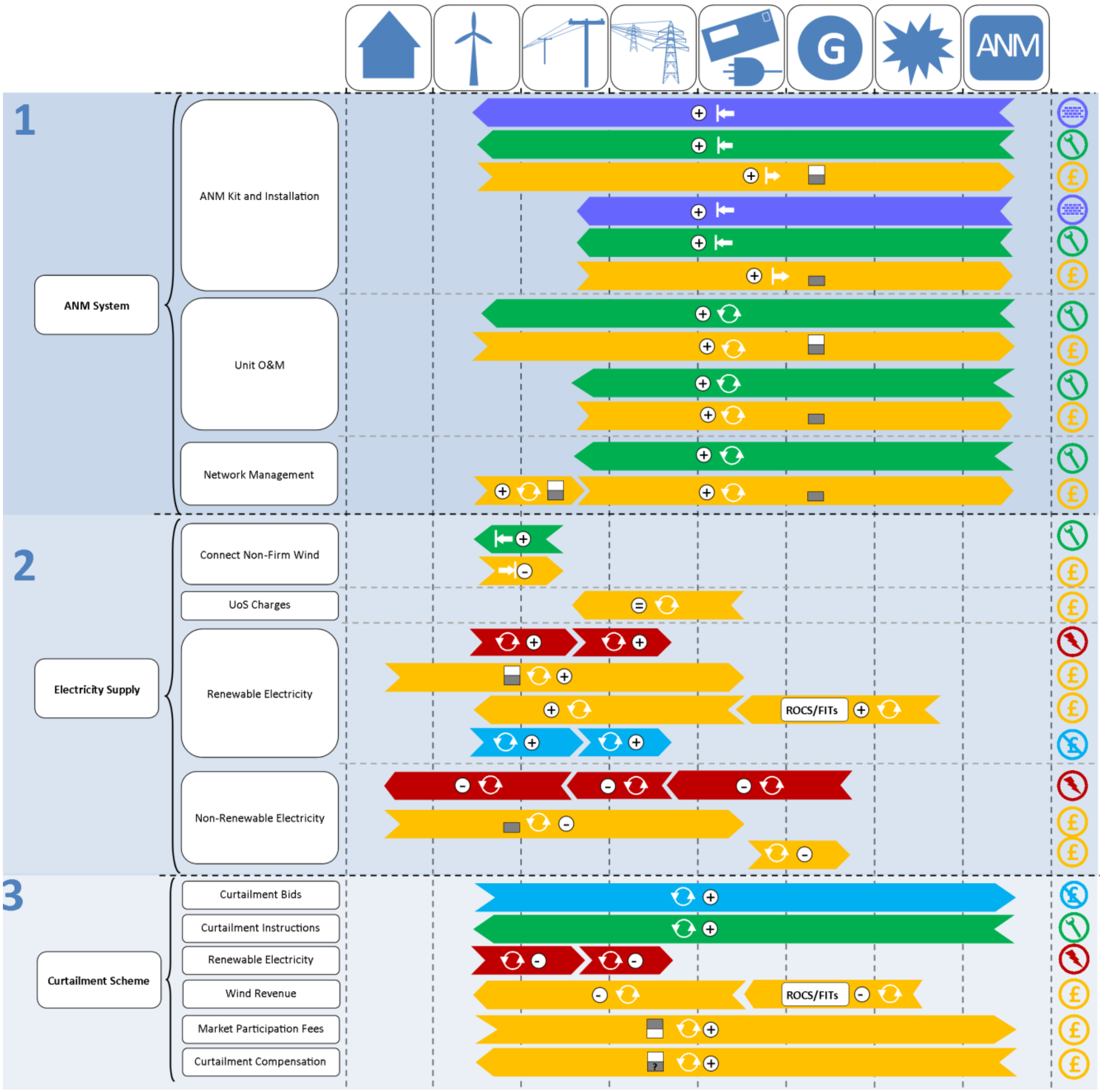

Figure 6-10 Business model of ANM scheme operating a Market PoA (Based on models developed by ECI [12]

In Strand Three of Figure 6-10, the diagram proposes a method of recovering the cost of running a curtailment market. The non-firm generators submit curtailment bids to the system on a regular basis, which could be hourly, daily, monthly or annually – depending on system operator preference. This model assumes that the ANM operator deals with individual non-firm generators directly however, it is possible that an Aggregator may act as a 'middle man' between ANM Operator and non-firm generators. This is similar to the VPP examples discussed in Chapter Two, and could also incorporate the Demand Side Management (DSM) users. This would allow small wind farms who are perhaps not experienced enough, or capable of dealing directly with a market system to benefit from the market ANM scheme. The bid value (£/MWh) gives an indication of the desire to be curtailed. This value is likely to reflect the value of lost ROCs or FITS and possibly additional running costs such as O&M and repayment interest.

Use of System charging can still be used to cover the cost of ANM installations; however any compensation to be paid to generators for reducing output will come from the curtailment market fund. This will be funded by charging a market participation fee. The market participation fee may take a form similar to BSUoS charges applied at to participants in the wholesale market at Transmission level in GB. [190]

It is unknown if the level of compensation received by the wind farms will be more, less or equal to that previously received through incentive schemes such as ROCs and FITs. This will depend on market competition, choice of compensation payment and will change over time.

In addition to the basic recovery of costs for the construction, operation and maintenance of the ANM scheme, there is the option to create ancillary services by incentivising domestic Demand Side Management (DDSM). The installation of storage devices in the homes of domestic customers is being trialled by Scottish & Southern Energy (SSE) for the Northern Isles New Energy Solutions (NINES) project [2]. As part of this project, SSE are also required to develop a sustainable business model to incentivise the uptake of storage devices in the homes of domestic customers and a mechanism through which to distribute the incentive.

6.6 The Wider Impacts of ANM

A study by Baringa and Smarter Grid Solutions Ltd for Elexon [169][8] in June 2014 discussed some of the issues regarding the impact of Active Network Management on wider system operation.

As the number of ANM schemes grow, so does the volume of distributed generation connected in each area. The current transmission system is built to facilitate flows from decentralised generation down through voltage levels to demand customers. As the number of centralised, local generation increases there is change in the pattern of electricity flows on the network. This may result in less demand at each GSP and even the potential for power to flow from distribution level up to transmission level.

[8] This report is private to Elexon however a copy of the report can be requested by contacting Elexon directly.

The report acknowledges the growth of ANM schemes, and predicts a marked increase in the number of ANM schemes at the end of the coming RIIO ED1 price control period (April 2015 – March 2023) as they become a key part of DNO business plans.

The issue with the growth of ANM schemes is that currently, the TSO is unaware of curtailment actions which take place at distribution level. While the volume of ANM connected DG is small, these imbalances have a low impact on wider system and market operation. As volumes of DG increase, accurate economic signals and local balancing becomes important for the efficiency of the whole system operation. A method of incorporating DG balancing into transmission balancing is required.

Two methods are proposed by Elexon to manage the growth of DG. The first is 'price based curtailment' similar to the market based arrangements discussed in this thesis. This method would see the Generator paying an 'additional charge' in return for curtailment compensation, and the compensation price would be capped. This value would be agreed during the connection application process. This can be compared to the 'market fee' proposed in Section 6.5.2.

The second method is an Integrated Local Balancing system. In this arrangement, the generator submits bids and offers for curtailment. A location specific increment to the DNUoS is paid by the generator to account for the ANM/balancing mechanism (similar to that proposed in the business models in Section 6.5). The TSO interacts with the Distribution System Operator (DSO) and the DSO can submit its own bids to the National Balancing Mechanism. The Settlement process takes in to account both local and National balancing actions.

The publication of this report highlights the importance of the topics addressed in this thesis, and the impact that ANM is having on the wider energy system. The number of distribution connected generation is growing and the industry has noticed that current non-market arrangements will not be suitable for long term network operation. A move towards market arrangements, and eventually a fully integrated balancing mechanism will allow safe and secure network operation while allowing further renewables to connect to the system.

These models were presented to Work Stream 6 of the Smart Grid Forum in June 2014 [191]. The group proposed that the models should be added to their own report (working documents can be found [192]) and it was strongly recommended that these models would need to be trialled as soon as possible in order to test the concepts and feasibility of proposed models. Baringa proposed a number of 'Innovation' options for these trials, including:

- Improving existing ANM through data visibility and transparency
- Simple market models to incentivise efficiency by creating a price for curtailment
- Testing the concept of a local balancing mechanism

All three of which will lead to further understanding of more complex management of distribution systems and how they can be better utilised to improve overall system operation.

6.7 Conclusions

This chapter has discussed the cost of traditional reinforcements and ANM schemes in the UK. As Ofgem encourages DNOs to move towards BAU for ANM schemes, there is a need to determine how network owners and operators will recover costs associated with ANM schemes. There are a number of different ways in which network operators could recover costs and a qualitative analysis of the options led to the development of the business models presented in Figure 6-8 and Figure 6-10. The development of new BAU cases will depend on a number of factors, including regulation changes, distribution code changes, market configurations, etc. The more changes required by any proposed business model, then the more difficult it may be to implement these within a reasonable time frame.

In the long run, markets can result in improved return on investment for generators and a more efficient electricity system operation however there are still a large number of issues to consider with regards to curtailment markets and wider ANM roll out. The inclusion of such technical difficulties, mean that the initial benefits of market PoA are not always apparent.

For centralised ANM equipment i.e. the central controller, there are uncertainties as to how the cost of such large, shared equipment will be recovered. One option is to charge the initial group of non-firm generators connecting to the scheme through cost apportionment i.e. the cost is distributed based on capacity of generators. A second option, and the one which is proposed in Figure 6-8 and Figure 6-10, is to recover the cost of shared ANM equipment through DNUoS charging. This would result in some of the cost being passed on to demand customers and the DNO would have to justify this additional cost to the regulator.

Curtailment of wind generation will result in a reduced profit for the wind farm owners from ROCs or FITs – however this could be compensated through use of a market curtailment scheme. Depending on the size of market participants, and number of competitors, the level of compensation will vary. It is unknown if this will be higher or lower than ROC/FIT levels. A fixed price of compensation could be agreed in advance of the curtailment actions which would give developers a method of estimating the impact on income.

The two business models proposed in Section 6.5.1 and 6.5.2 present just one method of recovering the costs of ANM schemes under a BaU practice. It is under the discretion of the DNO how they choose to fund their ANM schemes. In the future, questions may arise as to what should happen when network reinforcements are eventually required. These questions include who should pay for reinforcements and what might happen to existing non-firm connections that are currently in place.

UKPN have raised this issue of future reinforcements as part of the FPP project [193] however there is no obvious solution to the problem of who pays for reinforcements. UKPN has set out two options: mandatory or voluntary reinforcements. Under mandatory reinforcements, an agreement would be placed in to the connection arrangement wereby generators would be obliged to fund reinforcements at a pre-agreed price. Under a voluntary reinforcement arrangement, generators would be given the option to fund reinforcements in exchange for a firm connection. If they declined this option, they would remain as non-firm generators and subject to potential curtailment. There is an uncertainty under the voluntary arrangement that none of the existing generators would be willing to fund reinforcements. In this case the cost would most likely fall to the new generators wishing to connect to the network, and the existing generators will still be subjected to the non-firm connection arrangements prior to reinforcements.

In addition to the issues surrounding reinforcement, there could be a case for changing the PoA when a capacity cap is reached. FPP have proposed a pro rata arrangement up to 35 MW, after which any new generation connecting to the scheme will be entered into a LIFO arrangement. This arrangement is agreed as part of the connection agreement however the method of curtailment could be changed, assuming the change would not have a negative impact on existing connection arrangements. An example of changes to connection agreement is demonstrated on the Irish transmission system [59], as discussed in Section

2.4.3.9. The decision to remove compensation payments from wind generators was viewed as controversial as this could have an impact on the return on investment for developers.

PoA and non-firm connections are still very much in the early stages of development and there are many issues yet to be address by DNO and regulators. DNO innovation and trials are an essential part of developing this area of the industry and are required to move towards the best way of managing the energy system as a whole.

The next, and final chapter will bring together all of the key arguments and knowledge contributions discussed in this thesis and discuss any further work which may be related to this thesis.

7 Conclusions

7.1 Chapter Summary

This chapter begins with a review of the main conclusions presented in this thesis. The contributions to knowledge are then identified and discussed and the chapter concludes with possible future work.

7.2 Conclusions

Each chapter of this thesis has contributed to the learning in the research field of Principles of Access (PoA) in Active Network Management (ANM) systems, and provided discussion on the topic of PoA and whether there are more suitable alternatives to the LIFO approach.

Renewable Energy Grid Integration Issues

The literature review highlighted the issues, described below, concerning network owners, operators and generation developers. There are three sets of issues which can result in delays to the connection of renewable generators:

- Network issues which focus on local issues such as lack of capacity on the network to enable new connections, and also control of voltage and reactive power levels on the network.
- System issues which can include security of supply, back up reserve and system balancing. Systems which are overloaded with new generation may have difficulty in balancing generation and demand.
- Market issues such as subsidies, compensation for curtailment, use of system charging and electricity pricing.

These issues have been dealt with at transmission level by fast-tracking renewable connections ahead of transmission upgrades and paying compensation to generators when they are not able to export energy to the transmission network as a result of network constraints. The issues are also prevalent at distribution level however the method of management of constraints is different from that at transmission. The introduction of ANM schemes at distribution level has allowed distribution networks to operate in a manner similar to transmission networks – with active management of power flow and voltage levels. Current knowledge of renewable grid integration issues shows that network constraints are a real issue, with fewer options being promoted in distribution networks but with ANM being identified as a highly promising development. Utilising ANM schemes, the distribution network owner can now offer reduced cost connections to renewable generators in exchange for reduction in output during times when the network is at capacity.

Conclusions from the review of Principles of Access

PoA are used to define the rules and relationships between the generation, demand and network constraints. They define the order in which generation will be curtailed. The literature review has presented a number of PoA which have been utilised in ANM schemes in the UK, and others which have not yet been utilised but which have the potential for further study. PoA for distribution level has been discussed in the literature, but not to any significant detail. The majority of examples come from transmission level.

To better assess PoA, methods were split into two categories; market and non-market PoA. Non-market PoA were defined as those which have rules defined by the DNO and which do not grant compensation to generators during each curtailment event. Market arrangements can be defined as those which have compensation arrangements defined by the DNOs, and which require the creation of a curtailment market at distribution level in order to determine the order of curtailment for generators on the network.

Further assessment of curtailment market design was undertaken in order to better understand the implications of market PoA and to determine the way in which a market PoA might operate at distribution level. In order to critically assess the PoA, an assessment criteria was used to score each of the PoA. The highest scoring PoA when qualitatively assessed against the criteria were selected for further study and are:

- Non-market PoA

    - Last In First Off
    - Pro Rata
    - Rota
- Market PoA
    - Market with pay-as-bid compensation mechanism
    - Market with system price compensation mechanism
    - Market with a fixed price compensation mechanism

The review of PoA shows that this is an important area of network access arrangements in distribution networks and a key enabler for ANM. The literature yielded various options for PoA and these are used as the starting point for the research presented in this thesis.

The Optimal Power Flow modelling approach

The OPF approach to quantitatively asses PoA presented in Chapter Four demonstrates a method of applying curtailment scenarios to network case studies while ensuring safe and secure network operation is maintained during curtailment of generation.

This method can be used to apply PoA to both non-market and market arrangements. To apply non-market principles of access, the cost function of the non-firm generator is set relative to the other firm and non-firm generators and a curtailment order is created. For example, the most expensive generator will be curtailed first. The key parameter is the cost gradient of each generation unit, as it is the rate of change which determines the curtailment order via the OPF solver. When a share of curtailment is required, e.g. under a Pro Rata PoA, additional constraint equations can be applied to the OPF to ensure the correct curtailment agenda is adhered to.

While there are simplifications applied to the market modelling which does not necessarily capture all of the behavioural effects which might impact upon market bidding procedures, the curtailment of the generators is applied using the same OPF method and therefore capacity factors and network losses can be compared directly.

Sensitivity studies presented in Chapter Four and Chapter Five highlight the impact of network losses on the curtailment of generation. When the costs of all generators are set equal, i.e. they have the same priority in the curtailment stack, the OPF will curtail the generator which will minimise the losses on the network. Based on the results presented in this thesis, it has been concluded that the OPF solver will select the generators located furthest away from the constraint, to clear the constraint. In this particular example, these generators also have the largest capacity when compared with the other generators and so it is assumed by reducing their output, the losses on the network are significantly reduced without having to request curtailment from the other generators.

Comparison of market and non-market Principles of Access

The simple case study results presented in Chapter Four demonstrate some of the key characteristics of the PoA proposed in this thesis:

- A LIFO PoA results in relatively low capacity factors for the last generator connected to the network
- Pro Rata and Rota arrangements provide a fairer, more balanced range of capacity factors across all of the non-firm generators
- Market arrangements demonstrate that costs of curtailment could be lowered if a market for curtailment were introduced, based on indicative costs for non-market arrangements which provides an indication of lost revenue

Key results from the base case are presented in Table 7-1**.**

Table 7-1 Capacity factor results from the base case model studied in Chapter Four

	LIFO	Pro Rata	Rota	PAB	CMCP
Gen A	0.59	0.42	0.5	0.59	0.59
Gen B	0.59	0.42	0.45	0.18	0.18
Gen C	0.47	0.42	0.36	0.59	0.59
Gen D	0.18	0.42	0.33	0.59	0.59
Gen E	0.11	0.42	0.41	0.59	0.59
Avg.	0.39	0.42	0.41	0.51	0.51

Using different network topologies has allowed these characteristics to be compared thoroughly and a validation of the model using spreadsheet calculations grants confidence in the model for use in more complex network topologies.

The Orkney Case Study results presented in Chapter Five focus on the impact of PoA in a real network case study, and the first serious deployment of ANM in the UK. This study has highlighted the impact of curtailment arrangement on network losses and therefore overall required curtailment. While the capacity factors and losses are particular to this network study, the key results will apply to any network utilising PoA. The key results from the study of non-market arrangements are as follows:

- Applying a LIFO arrangement will result in smaller capacity factors for those generators at the bottom of the priority stack when compared with arrangements such as Pro Rata and Rota. For example, the last generator in the stack has a minimum capacity factor of 0.33 compared with a minimum of 0.44 under a Pro Rata arrangement, or 0.43 under a Rota arrangement.
- The losses on the network are linked to the size and location of generation in relation to the constraint. Neither LIFO, Pro Rata nor Rota arrangements can guarantee the minimisation of losses on the network. The LIFO PoA results in a 2 GWh increase in annual system losses when compared with the Technical Best arrangement.
- A Rota arrangement can give a balance of curtailment across a long time period e.g. upwards of a year, however this will depend on the levels of constraint on the network and the frequency of rotation. The capacity factors experience under a Rota PoA range of 0.43 to 0.46 which compares to a LIFO range of 0.33 to 0.51.
- A Pro Rata arrangement ensures a fair share of the curtailment across all generation connected to the network. All generators have a capacity factor of 0.44. The Pro Rata arrangement leads to a higher minimum capacity factor when compared with LIFO, leading to the conclusions that the DNO could connect more generation under a Pro Rata arrangement than under a LIFO arrangement while ensuring an economically viable capacity factor.

Comparison of market arrangements has provided an initial study of distribution network markets. The simple method proposed in this thesis gives an indication of behaviours and expected outcomes. The key results are as follows:

- When basing bids on assumed lost revenue, smaller generators are entitled to more FIT subsidies and will initially place higher bids when compared with larger generators. Wind generators less than 1.5 MW are entitled to £107/MWh, wind generators between 1.5 MW and 5 MW only receive £50.5/MWh based on 2012 prices.

- When basing bids on assumed lost revenue, the bidding behaviour will be divided into groups based on the level of subsidies each generation size is entitled to. Depending on size these groups may be distinctly separate.
- The Curtailment Market Clearing Price (CMCP) arrangement will result in higher overall costs of curtailment in networks where many generators are required to clear the constraint, perhaps during highly constrained periods – as the highest bid price will then be paid to all generation. This is classical market behaviour of abnormal prices in a short market. This could guide investment decisions to resolve such high costs.
- The design of the market PoA are fairly standard and are based on examples from the literature. The Pay-as-bid (PAB) market model is used in the GB electricity market currently and the Curtailment Market Clearing Price (CMCP) model is also used in the GB electricity market to determine the system buy and sell price as part of the balancing mechanism.
- The methods used to model bid behaviour are simple logic commands. More in depth methods such as Agent Based Modelling or Swarm Optimization may provide an additional level of insight in to the behaviour of generators bidding in to curtailment markets.

The sensitivity studies presented in Chapter Four and Chapter Five provide conclusions on alternative network configurations, curtailment stack configurations and market manipulation. The key conclusions from the sensitivity studies are as follows:

- The sensitivity studies performed on the case studies have demonstrated the importance of generation mix, both in terms of technology and capacity. For the LIFO arrangement, larger generators at the bottom of the priority stack will result in fewer generators being affected by curtailment. This opens up a possible opportunity for larger generators being signed up for ANM in order to reduce the complexity and scale of the ANM system however this may only be feasible when there are suitable compensation mechanisms in place. In the technical best arrangement the generators further away from the constraint are used to solve the network constraints due to losses sensitivity. Similarly under a market PoA, the larger generators are used to clear the constraints due to low bid prices. In this particular case study, the generators located furthest from the constraint are also the largest generators. Both PoA results in a reduction in system losses. This result supports the conclusion that a market scenario could provide a more efficient network operation when compared with a LIFO arrangement. This would depend on the particular network topology and generation mix and technology in question.

- In the market studies, when more generators are added to the generation mix, the costs and system prices are affected due to the change in bid groups i.e. swapping a large generator with a low pre-curtailment cost for multiple small generators with higher pre-curtailment costs. A curtailment market with a large number of small generators would results in a high price curtailment market based on the cost methodology used in this thesis. This result suggests that DNOs would not be willing to facilitate a market on a network with multiple small generators. The cost of curtailment would be high, and it may also be an unattractive option for smaller generators who do not have the experience or capability to participate in a market environment.
- Changing pre-curtailment profit levels does not have a significant impact on the curtailment behaviour of the market PoA due to the cost methodology used i.e. all generators have the same pre-curtailment profit levels, with the only variation being the FIT or ROC subsidy level each generator is entitled to. By applying 5-10% increases and decreases to the FIT or ROC subsidy level there is little impact on the curtailment behaviour because the bid levels do not vary significantly. Should other parts of the cost calculation vary in addition to varying the FIT or ROC subsidy payment, then a wider range of results may be achieved. This could also be influenced by a more diverse mix of generation which would almost certainly result in a wider range of pre-curtailment profit levels.
- The effect of changing the bid step change (from a set value of 0 or 5, to a random value between 0 and 10) does not have a significant impact on the curtailment behaviour over a period of time.
- When gaming occurs in the market i.e. one or more generators submit bids much higher than the assumed pre-curtailment profit level, this has an impact on total system costs and in particular, when there are instances of high curtailment and all generation is required to curtail. This affect is seen more significantly in the CMCP market model with larger spikes for the system price. Game theory is a major consideration for any market participant and this could result in adverse outcomes

for smaller generators if they do not anticipate all market bid strategies, or have the ability to learn and adapt bid techniques over time.

The results of the modelling provide evidence to support alternative PoA to the LIFO arrangement which has been the arrangement selected by the majority of DNOs to date. Definitively there are other more attractive alternatives to LIFO on the basis of improved average capacity factors for generators connected to ANM system, and in terms of system efficiency and losses minimisation.

Pro Rata and Rota arrangements present an option to allow increased capacity factors for those generators who might experience unattractive low capacity factors under a LIFO arrangement. The market arrangements present an option for distribution curtailment in the future. While the establishment of any such market at distribution level would be a lengthy process that would not only require changes to the grid and distribution codes but also time and supporting infrastructure investment from the DNO. The market arrangement may reflect a more accurate description of curtailment and ANM schemes in the future as the growth of ANM at distribution system operation starts to impact on transmission system balancing. Fixed price compensation would be a suitable stepping stone between non-market arrangements such as LIFO, towards a full curtailment market at distribution level and this fixed price could be in some way linked to system prices at Transmission level in a bid to link distribution better to transmission.

Business As Usual application of Principles of Access in Active Network Management Schemes.

As DNOs move towards BaU for ANM schemes, there is a need to determine how network owners and operators will recover costs associated with ANM schemes. There are a number of different ways in which network operators could recover costs and a qualitative analysis of the options led to the development of the business models presented in Figure 6-8 and Figure 6-10. These models provide a visual demonstration of the flow of goods and services between stakeholders involved in an ANM scheme. The cost recovery methodology is based on the current method of recovering traditional network reinforcement i.e. via Use of System charging.

The development of new BAU cases will depend on a number of factors, including regulation changes, distribution code changes, market configurations, etc. The more changes required by any proposed business model, then the more difficult it may be to implement these within a reasonable time frame.

For centralised ANM equipment e.g. the central controller, there are uncertainties as to how the cost of such large, shared equipment will be recovered. The method for recovering costs of ANM proposed in this thesis is to recover the cost of shared ANM equipment through Use of System charging. This would require initial upfront investment from the DNO, and charges recovered through the standard Use of System charging methodologies as is current practice for standard reinforcement costs.

Curtailment of wind generation will result in a reduced profit for the wind farm owners from ROCs or FITs – however this could be compensated through use of a market curtailment scheme. Depending on the size of market participants, and number of competitors, the level of compensation will vary. It is unknown if this will be higher or lower than ROC/FIT levels. A fixed price of compensation could be agreed in advance of the curtailment actions which would give developers a method of estimating the impact on income.

Overall Conclusions

Based on current UK distribution network activity, ANM is growing in importance. Different technologies have been trialled and are now beginning to be rolled out and international interest in ANM schemes is increasing. Commercial issues have always been evident in the field of Smart Grids but are now growing in interest and importance in parallel with technological advances. PoA have material implications for generator viability, network investment and charging, and overall system economic efficiency. This work has pointed the way towards adopting alternative PoA to the common LIFO method. Adoption of alternative PoA during network innovation trials will increase the knowledge and learning available to distribution network owners and operators. There is potential to increase the volume of generation which can connect to a network and still have a feasible return on investment by adopting alternative PoA.

The results of the case studies show that using alternatives to a LIFO arrangement can result in an increase of capacity factor for wind generation under non-firm arrangements when connected to an ANM scheme. A Pro Rata or Rota arrangement can give a balance of curtailment between all generators connected to the ANM scheme however neither LIFO, Pro Rata nor Rota PoA can guarantee the minimisation of losses on the network.

Market arrangements grant more control to the generator with regards to when and how much they are curtailed by and compensation is paid thus reducing the loss of income. When basing compensation on lost revenue, smaller generators will place higher bids when compared with larger generators. This will also result in groups of bids determined by generator size. The CMCP arrangement results in high overall costs of curtailment due to high system prices during periods of high curtailment on the network.

Non-market arrangements are better suited for application under current network codes and standards, however market arrangements may be better suited to future network scenarios. Fixed price compensation would be a suitable stepping stone between the two in a bid to better link transmission and distribution system operation better.

The electricity system and market are both going through a period of change. The last five years have resulted in a large amount of innovation and new methods of system operation and commercial arrangements have been developed. However, the transfer from innovation to BaU is still to take place. This applies both to the network operators and to the regulatory framework. The next twenty years will involve a fundamental shift in the way network owners and operators run the system and it will move further away from the tradition passive model, in to a more integrated and active system. This will require the regulator to change and adapt accordingly in order to ensure that this process is incentivised in the right manner and to continue to encourage network owners and operators to manage the system in the best fashion while ensuring value for money for energy consumers.

7.3 Contributions to Knowledge

The conclusions presented in the previous section highlight the way in which this thesis has attempted to answer the research question “Are there suitable alternatives to LIFO for non-firm wind generators connected to Active Network Management schemes?” The following statements provide details on the contributions to knowledge made in this research area throughout this thesis.

Provide further definition of PoA

Chapter Two provides an extensive background review of the motivation behind the growth of ANM schemes in the UK, the GB Electricity Market and Regulation within which DNOs must create and manage ANM schemes. This work identifies the key issues associated with the implementation of PoA, which are similar to the general network access issues applicable to all generators operating at both distribution and transmission level.

Provide a qualitative assessment of PoA based on PoA models in the literature

In Chapter Three, an extensive review of PoA is provided. A selection criterion is used to compare different PoA and discuss the advantages and disadvantages of each. These criteria have been used in previous reviews of existing regulation and network codes and is therefore appropriate to apply this to the assessment of PoA. This qualitative discussion identifies six PoA for further quantitative analysis, and the chapter provides a reference point for future studies and discussions regarding PoA.

Provide a quantitative analysis of PoA based on wind power capacity factors under curtailment action

A quantitative assessment of both market and non-market PoA is presented in Chapters Four and Five. The OPF method is first defined in Chapter Four. Generator cost functions are used to apply the curtailment order, additional constraint equations can be added as required and the method can also be adapted to apply market PoA through the application of simple logic controls to change the generator cost functions, and therefore curtailment order. Key aspects of different PoA are first demonstrated on a simple four bus network example. This then follows on to a more complex, real life network example based on the Orkney distribution network. A number of sensitivity studies are carried out to explore different factors which affect the outcome on capacity factors of different PoA. The novel contribution is the use of an OPF method to quantitatively assess both market and non-market PoA. The results include a comparison of the impact on curtailment, as well as the cost of curtailment under all six PoA proposed in this thesis. This provides valuable reference material for future PoA studies and ANM scheme developments.

Assessment of the potential for a curtailment market at distribution level

Currently in the UK, non-market PoA have been adopted. This thesis presents a discussion on the move of distribution networks towards market curtailment scenarios in the future. This discussion is presented across a number of chapters. The design of curtailment markets is discussed in Chapter Three, the impacts of Market PoA are modelling in Chapters Four and Five using an OPF methodology, and the business model of a market PoA is presented in Chapter Six. This thesis provides a valuable starting point in to the research area of curtailment markets at generation level. This is an area of research which is expected to become more prevalent as the number of ANM schemes, and therefore the capacity of generation connection at distribution levels, increases and begins to impact on wider transmission system balancing.

Assess ANM Business As Usual implications for DNOs

DNOs are beginning to offer non-firm connections alongside standard firm connections. This will require a change to DNOs BaU operations. This work proposes that DNOs might recover the costs of ANM schemes through the use of system charging methodologies that are currently used to recover the cost of traditional reinforcements. A visual aid to demonstrate the benefits and to illustrate the flows of goods and services within an ANM scheme is presented. This method can be used to demonstrate a number of alternative cost models for ANM schemes in the future.

7.4 Further Work

The main objective of this work was to explore alternative PoA in ANM schemes than those currently being utilised by DNOs. Whilst this thesis has demonstrated a number of alternative PoA, and compared the impact of each of these PoA on the curtailment of wind generation, there are several strands of further work which could be undertaken to better understand PoA and their implications.

Different ways to assess market based PoA

The market based PoA presented in this thesis were assessed using an OPF method, however a more detailed analysis of a curtailment market using agent based modelling or similar, would present further results on the behaviour of market participants and the effect a number of external factors may have on the bids and offers of generators. In relation to this, a more detailed analysis of curtailment market design could be carried out.

Exploration of PoA and voltage constraints

This work has focused on the curtailment of wind generation based on thermal constraints, but voltage constraints have equal bearing in terms of importance and concern for network operators. This will be particularly relevant in network areas with high volumes of PV generation connected to the network. Voltage constraints are more complex and further thinking is required in terms of how to apply curtailment rules to generation in networks with single or multiple voltage constraints.

Optimal ANM configurations based on technical/PoA considerations

Further work could be done to determine a framework for designing the optimal ANM configuration and PoA for a particular network, based on certain characteristics. Factors which this work has shown to influence PoA performance includes generation mix, generation capacity, network topology and compensation levels. By developing decision making techniques and processes, this research would enable DNOs to consider all the factors which were particular to their network, and select the optimal ANM configuration and the PoA which would meet their desired aims. This could be to minimise network losses, to connect as much renewable generation as possible or to ensure a particular capacity factor for all non-firm generation.

The wider impact of ANM on transmission operation

The wider impact of ANM is discussed briefly in Chapter Six, however further studies could be presented on the impact of ANM growth on transmission behaviour. The growth of distributed connection generation is inevitable given the current market support, it would therefore be an important research area to consider how balancing at distribution level may in future, impact on the balancing actions at transmission level. This could lead to development of new ANM techniques and solutions, in addition to further study of PoA.

Investment strategy

As ANM becomes a standard option for DNOs, a further study in to the investment cost strategy would provide significant contribution to the research field. While the costs of traditional reinforcements are widely available, the costs of ANM systems are at present, tied up within incentive funding mechanisms. Standardisation of ANM systems will lead to fixed costs which can then be directly compared with traditional reinforcement costs. 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.

Implications for PoA/ANM for non-wind renewables and non-renewable generation

This work has focused on the implications of alternative PoA on the capacity factor of wind generation. This is due to the high volume of wind connection to ANM schemes in the UK. However, there is value to be gained from addressing the impact of different PoA on the curtailment of other renewable generation, and non-renewable generation. The introduction in this thesis of a market PoA would allow non-renewable generation to feasibly participate in a curtailment scheme due to the compensation for reduced output during times of constraint. This type of study would also highlight the impact of ANM operation when there is a diverse mix of generation as opposed to a single dominant energy resource i.e. all wind or all PV.

PoA applied to storage or demand response.

There is currently a growth in the number of storage devices connected to ANM schemes in the UK. The use of battery and demand response is ideally suited to networks with a high percentage of intermittent generation. There storage devices and demand response could be contractually linked to other generators in the system and when said generator was curtailed, they could utilise the storage devices to prevent spilled energy. Alternatively, new PoA could be developed and applied to storage devices separately on the network. This could be expanded to look at the implications of whether a storage device is better utilised as a network asset to relieve constraints, or whether it is better connected to the network under a contract similar to the other non-firm generation on the system.

8 References

[1] Scottish and Southern Energy Power Distribution, “Orkney Smart Grid,” 2012. [Online]. Available: http://www.ssepd.co.uk/OrkneySmartGrid/ProjectInformation/.

[2] Scottish and Southern Energy Power Distribution, “Northern Isles New Energy Solutions (NINES),” 2012. [Online]. Available: http://www.ssepd.co.uk/News/NINES/.

[3] UK Power Networks, “Flexible Plug and Play.” [Online]. Available: http://www.ukpowernetworks.co.uk/internet/en/innovation/fpp/. [Accessed: 03-Apr-2013].

[4] Ofgem, “Low Carbon Network Fund,” 2014. [Online]. Available: https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund. [Accessed: 29-May-2014].

[5] National Grid, “Connect and Manage,” 2014. [Online]. Available: http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/connect-and-manage/. [Accessed: 30-Jun-2014].

[6] CIGRE Working Group C6.11, “Development and Operation of Active Distribution Networks,” 2011.

[7] R. A. F. Currie, G. W. Ault, C. E. T. Foote, N. M. McNeill, and A. K. Gooding, “Smarter ways to provide grid connections for renewable generators,” in *Power and Energy Society General Meeting, 2010 IEEE*, 2010, pp. 1–6.

[8] B. O’Neill, C. Foote, R. Macdonald, M. J. D. Member, S. Gill, and G. Milne, “Active Network Management on Islanded Systems : The Shetland Experience,” in *Innovative Smart Grid Technologies (ISGT Europe), 2013, 4th IEEE PES International Conference and Exhibition on*, 2013.

[9] J. Currie, R A F., O’Neill, B., Foote, C., Gooding, A., Ferris, R., Douglas, “Commercial Arrangements to facilitate active network management,” in *CIRED 21st International Conference on Electricity Distribution*, 2011.

[10] Baringa Partners and UK Power Networks, “Flexible Plug and Play Principles of Access Report,” 2012. [Online]. Available: http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/Project-Documents/FPP_Principles_of_Access_report_final.pdf.

[11] Scottish and Southern Energy, “Facilitate Generation Connections on Orkney By Automatic Distribution Network Management,” 2004.

[12] Environmental Change Institute at University of Oxford, “Supergen HiDEF Distributed Energy Business Modeling,” 2011. [Online]. Available: http://distributed-energy.ouce.ox.ac.uk/debmvefsplash.php#.

[13] UNFCC, “Kyoto Protocol to the United Nations Framework convention on climate change,” 1998.

[14] Ofgem, “RIIO: A new way to regulate energy networks,” 2010. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/51870/decision-doc.pdf.

[15] The European Parliament and the Council of the European Parliament, “Directive 2009/28/EC of the European Parliament on the promotion of the use of energy from renewable sources and amending and subsequetly repealing Directives 2001/77/EC and 2003/30/EC.” 2009.

[16] HM Government, “The UK Low Carbon Transition Plan - National Strategy for Climate and Energy,” 2009. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/228752/9780108508394.pdf.

[17] Scottish Government, “2020 Routemap for Renewable Energy in Scotland,” 2011. [Online]. Available: http://www.scotland.gov.uk/Publications/2011/08/04110353/0. [Accessed: 09-Apr-2013].

[18] UKWED, “UK Wind Energy Database,” 2014. [Online]. Available: http://www.renewableuk.com/en/renewable-energy/wind-energy/uk-wind-energy-database/index.cfm. [Accessed: 17-Jun-2014].

[19] Department of Energy and Climate Change, “UK Renewable Energy Roadmap Update 2013,” 2013.

[20] National Grid, “2014 Electricity Ten Year Statement,” 2014. [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/.

[21] National Grid, “Future Energy Scenarios,” 2014. [Online]. Available: http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/.

[22] Ofgem, “Ofgem,” 2014. [Online]. Available: https://www.ofgem.gov.uk/about-us. [Accessed: 16-Jun-2014].

[23] Elexon, “What we do,” 2014. [Online]. Available: http://www.elexon.co.uk/about/what-we-do/. [Accessed: 16-Jun-2014].

[24] National Grid, “Balancing Services,” 2014. [Online]. Available: http://www2.nationalgrid.com/uk/services/balancing-services/. [Accessed: 16-Jun-2014].

[25] Ofgem, “RIIO-T1 : Final Proposals for National Grid Electricity Transmission and National Grid Gas Final decision – Overview document,” 2012. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/53599/1riiot1fpoverviewdec12.pdf.

[26] Ofgem, “RIIO-T1 : Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd Final decision – Overview document Associated documents,” 2012. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/53746/sptshetlfp.pdf.

[27] UK Power Networks, “UK Power Networks Business Plan (2015 - 2023) Executive Summary,” 2014. [Online]. Available: http://library.ukpowernetworks.co.uk/library/en/RIIO/Main_Business_Plan_Documents_and_Annexes/UKPN_Overall_Executive_Summary.pdf.

[28] Northern Power Grid, “Our Business Plan 2015-23,” 2014. [Online]. Available: http://www.yourpowergridplan.com/#!

[29] Electricity North West, “Well Justified Business Plan 2015-2023,” 2014. [Online]. Available: http://www.enwl.co.uk/about-us/well-justified-business-plan-2015-2023/WJBPhome.

[30] Scottish and Southern Energy Power Distribution, “Business Plan Update,” 2014. [Online]. Available: http://www.yourfutureenergynetwork.co.uk/wp-content/uploads/2014/03/SSEPD-March-2014-Business-Plan-Update2.pdf.

[31] Scottish Power Energy Networks, “SP Energy Networks 2015 – 2023 Business Plan,” 2015. .

[32] Ofgem, “Feed-in Tariff Scheme,” 2013. [Online]. Available: http://www.ofgem.gov.uk/Sustainability/Environment/fits/Pages/fits.aspx. [Accessed: 09-Apr-2013].

[33] Ofgem, “Renewables Obligation,” 2013. [Online]. Available: http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Pages/RenewablObl.aspx. [Accessed: 09-Apr-2012].

[34] N. Cornwall and S. Littlechild, “Offtake arrangements and market access for small-scale distributed energy generators A Report for Ofgem,” 2008. [Online]. Available: https://www.ofgem.gov.uk/publications-and-updates/offtake-arrangements-and-market-access-small-scale-distributed-energy-generators.

[35] Department of Energy and Climate Change and Ofgem, “Calculating Renewable Obligation Certificates (ROCs),” 2013. [Online]. Available: https://www.gov.uk/calculating-renewable-obligation-certificates-rocs. [Accessed: 09-Apr-2013].

[36] e-ROC, “Track Record,” 2013. [Online]. Available: http://www.epowerauctions.co.uk/erocrecord.htm. [Accessed: 09-Apr-2013].

[37] Ofgem, “Renewables Obligation : Guidance for Generators,” 2014. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/87997/renewablesobligation-guidanceforgenerators1june2014.pdf.

[38] Ofgem, “Feed-in Tariff Payment Rate Table for Non-Photovoltaic Eligible Installations for FIT Year 5 (1 April 2014 to 31 March 2015),” 2014. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/87074/rpiadjustedtariffsnon-pvapril2014.pdf.

[39] Ofgem, “Feed-in Tariff Payment Rate Table for Photovoltaic Eligible Installations for FIT Year 5 (2014 / 15),” 2014. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/87468/fitpaymentratetableforpublication1july2014pvtariffs.pdf.

[40] Ofgem, “Feed-in Tariff Payment Rate Table for Photovoltaic Eligible Installations for FIT (1 April 2014 – 30 September 2014),” 2014. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/87468/fitpaymentratetableforpublication1july2014pvtariffs.pdf.

[41] C. Foote, R. Johnston, F. Watson, D. Macleman, and A. Urquhart, “Second Generation Active Network Management On Orkney,” in *22nd International Conference on Electricity Distribution, Stockholm*, 2013, no. 0659, pp. 10–13.

[42] TNEI Services Ltd, “Lincolnshire Low Carbon Hub,” 2013. [Online]. Available: https://www.lincolnshirelowcarbonhub.co.uk/. [Accessed: 27-May-2014].

[43] ENA, “Smarter Networks Portal,” 2014. [Online]. Available: http://www.smarternetworks.org/site.aspx. [Accessed: 29-May-2014].

[44] Ofgem, “Network innovation,” 2014. [Online]. Available: https://www.ofgem.gov.uk/network-regulation-?-riio-model/network-innovation. [Accessed: 29-May-2014].

[45] UK Government, “Electricity Market Reform,” 2014. [Online]. Available: https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform. [Accessed: 17-Jun-2014].

[46] Energy and Climate Change Select Comittee, “Draft Energy Bill: Pre-legislative Scrutiny,” 2012. [Online]. Available: http://www.publications.parliament.uk/pa/cm201213/cmselect/cmenergy/275/27502.htm.

[47] Department of Energy and Climate Change, “Electricity market reform : policy overview,” 2012. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48371/5349-electricity-market-reform-policy-overview.pdf.

[48] Department of Energy and Climate Change, “Planning our electric future: a White Paper for secure, affordable and low carbon electricity,” 2011.

[49] Department of Energy and Climate Change, "Electricity Market Reform Delivery Plan," 2013. [Online]. Available: https://www.gov.uk/government/publications/electricity-market-reform-delivery-plan.

[50] Committee on Climate Change, "Next steps on Electricity Market Reform – securing the benefits of low-carbon investment," 2013. [Online]. Available: http://www.theccc.org.uk/wp-content/uploads/2013/05/1720_EMR_report_web.pdf.

[51] National Grid, "Outturn Interim Report on the Connect and Manage Regime," 2013. [Online]. Available: http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/connect-and-manage/.

[52] CIGRE Working Group C5.04, "Congestion Management in Liberalized Market Environment," CIRGE, 2006.

[53] P. Higgins and A. M. Foley, "A methodology to analyse the impact of offshore wind forecasting error on electricity markets," *Environ. Electr. Eng. (EEEIC), 2013 12th Int. Conf.*, pp. 584–588, 2013.

[54] S. Fink, C. Mudd, K. Porter, and B. Morgenstern, "Wind Energy Curtailment Case Studies," 2009. [Online]. Available: http://www.nrel.gov/docs/fy10osti/48737.pdf.

[55] S. Sharma, C. D'Annunzio, S. Badri, S.-H. Huang, N. D. R. Sarma, I. Flores, B. Blevins, and R. Surendran, "ERCOT tools used to handle wind generation," *Power Energy Soc. Gen. Meet. 2012 IEEE*, pp. 1–7, 2012.

[56] EirGrid, "All Island TSO Facilitation of Renewables Studies," 2010. [Online]. Available: http://www.eirgrid.com/media/FacilitationRenewablesFinalStudyReport.pdf.

[57] I. M. Dudurych, J. O'Sullivan, a. Rogers, D. Bell, S. Rourke, and N. Kamaluddin, "Tools for handling high amounts of wind generation in National Control Centre in Ireland," *Power Energy Soc. Gen. Meet. 2012 IEEE*, pp. 1–8, Jul. 2012.

[58] EirGrid, "Wind Farm Controllability Categorisation Policy," 2012. [Online]. Available: http://www.eirgrid.com/media/Wind Farm Controllability Categorisation Policy.pdf.

[59] Single Electricity Market, "Treatment of Curtailment in Tie-break situations," 2013. [Online]. Available: http://www.allislandproject.org/en/transmission_current_consultations.aspx?article=2ac7b907-d8bf-4451-b111-34704b99d0c2.

[60] National Grid, "Getting more connected," 2014. [Online]. Available: http://www2.nationalgrid.com/About-us/European-business-development/Interconnectors/.

[61] Moyle Interconnector Ltd, "Moyle Interconnector Access Rules," 2012. [Online]. Available: https://www.ofgem.gov.uk/publications-and-updates/approval-moyle-interconnector-access-rules.

[62] Single Electricity Market Committee, "Curtailment Approach on SEM Interconnectors," 2013. [Online]. Available: http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=7ef81e9f-949e-474e-848c-45934650fa48.

[63] Ofgem, "BritNed Access Rules," 2012. [Online]. Available: http://www.ofgem.gov.uk/Europe/Documents1/BritNed Access Rules.pdf.

[64] Network Rail, "Our Routes," 2014. [Online]. Available: http://www.networkrail.co.uk/structure-and-governance/our-routes/. [Accessed: 19-Jun-2014].

[65] Office of Rail Regulation, "Home Page," 2014. [Online]. Available: http://www.orr.gov.uk. [Accessed: 19-Jun-2014].

[66] Office of Rail Regulation, "Access Options - Final Conclusions," 2008. [Online]. Available: http://orr.gov.uk/__data/assets/pdf_file/0013/2065/349.pdf.

[67] National Grid, "Shipper Interconnectors," 2014. [Online]. Available: http://www2.nationalgrid.com/uk/services/gas-transmission-connections/shipper/shipper-interconnector/. [Accessed: 19-Jun-2014].

[68] National Grid, "Application to Offer," 2014. [Online]. Available: http://www2.nationalgrid.com/UK/Services/Gas-transmission-connections/Connect/Application-to-offer/. [Accessed: 19-Jun-2014].

[69] National Grid, "Prevailing View," 2014. [Online]. Available: http://marketinformation.natgrid.co.uk/gas/frmPrevalingView.aspx. [Accessed: 19-Jun-2014].

[70] National Grid, "Service Reports," 2014. [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Services-Reports/. [Accessed: 18-Jun-2014].

[71] The Carbon Brief, "Why windfarms get paid to switch off," 2013. [Online]. Available: http://www.carbonbrief.org/blog/2013/03/why-windfarms-get-paid-to-switch-off. [Accessed: 18-Jun-2014].

[72] National Grid, "March 2014 Monthly Balancing Services Summary," 2014. [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Services-Reports/.

[73] Embedded Generation Working Group, "Report into Network Access Issues," 2001. [Online]. Available: http://webarchive.nationalarchives.gov.uk/20100919181607/http:/www.ensg.gov.uk/assets/21_10_2002_main_report.pdf.

[74] Ofgem, "Ofgem's Response to the Embedded Generation Working Group Report on Network Access Issues," 2001. [Online]. Available:

https://www.ofgem.gov.uk/publications-and-updates/ofgems-response-embedded-generation-working-group-report-network-access-issues.

[75] R. A. F. Currie, G. W. Ault, C. E. T. Foote, and J. R. McDonald, "Active power-flow management utilising operating margins for the increased connection of distributed generation," *Gener. Transm. Distrib. IET*, vol. 1, no. 1, pp. 197–202, 2007.

[76] R. MacDonald, R. A. F. Currie, and G. W. Ault, "Project Report: Active Networks Deployment Register," 2008. [Online]. Available: http://webarchive.nationalarchives.gov.uk/20100919181607/http:/www.ensg.gov.uk/index.php?article=95.

[77] R. A. F. Currie, G. W. Ault, C. E. T. Foote, G. M. Burt, and J. R. McDonald, "Fundamental research challenges for active management of distribution networks with high levels of renewable generation," in *Universities Power Engineering Conference, 2004. UPEC 2004. 39th International*, 2004, vol. 3, pp. 1024–1028 vol. 2.

[78] R. A. F. Currie, G. W. Ault, and J. R. McDonald, "Methodology for determination of economic connection capacity for renewable generator connections to distribution networks optimised by active power flow management," *Gener. Transm. Distrib. IEE Proceedings-*, vol. 153, no. 4, pp. 456–462, 2006.

[79] SSEPD, "SSEPD ANM Status," 2013. [Online]. Available: http://anm.ssepd.co.uk/ANMGen.aspx. [Accessed: 20-Aug-2013].

[80] KEMA, "Smart Grid Strategic Review: The Orkney Islands Active Network Management Scheme," 2012.

[81] A. Urquhart and D. MacLeman, "LCNF Tier 1 Close-Down Report Orkney Energy Storage Park," 2013. [Online]. Available: http://www.ssepd.co.uk/WorkArea/DownloadAsset.aspx?id=2157.

[82] SSE plc, "Orkney Energy Storage Park Official Opening," 2013. [Online]. Available: http://www.youtube.com/watch?v=O437QqgcBTI. [Accessed: 20-Jun-2014].

[83] S. Gill, G. W. Ault, I. Kockar, C. Foote, and S. Reid, "Operating A Wind Farm In The Future Smart Grid - Lessons From Designing and Deploying A Smart Grid On Shetland," in *European Wind Energy Association (EWEA) Conference, Vienna 2013*, 2013.

[84] I. Elders, "Additional Wind Generation Connection to the Shetland Power System," 2006.

[85] M. J. Dolan, G. W. Ault, D. F. Frame, S. Gill, I. Kockar, O. Anaya-Lara, S. Galloway, B. O'Neill, C. Foote, and A. Svalovs, "Northern Isles New Energy Solutions: Active network management stability limits," *Innovative Smart Grid Technologies (ISGT Europe), 2012 3rd IEEE PES International Conference and Exhibition on*. pp. 1–9, 2012.

[86] Ofgem, "Decision to approve changes to Scottish Hydro Electric Power Distribution (SHEPD) plc's Norther Isles New Energy Solutions (NINES) project," *Vasa*, 2013.

[Online]. Available: https://www.ofgem.gov.uk/publications-and-updates/decision-approve-changes-scottish-hydro-electric-power-distribution-shepd-plc%E2%80%99s-%E2%80%93-northern-isles-new-energy-solutions-nines-project?docid=740&refer=Networks/ElecDist/Policy&utm_source=Ofgem Website Mailing List&utm_campaign=2f5a0e0617-Ofgem_Email_Alert5_28_2013&utm_medium=email&utm_term=0_a9e586c268-2f5a0e0617-376768341. [Accessed: 16-Aug-2013].

[87] TNEI Services Limited, "Assessment of the Grid Connection Options for the Scottish Islands Highlands and Islands," 2007.

[88] Scottish and Southern Energy Power Distribution, "Shetland Energy," 2015. [Online]. Available: https://www.ssepd.co.uk/ShetlandEnergy/. [Accessed: 18-Jan-2015].

[89] Eon, "Innovation in Central Networks' Registered Power Zone," 2005. [Online]. Available: http://www.eon-uk.com/CentralNetworksRPZ1406.pdf.

[90] UK Power Networks, "Flexible Plug and Play Low Carbon Networks Second Project Progress," 2012. [Online]. Available: http://www.ofgem.gov.uk/Networks/ElecDist/lcnf/stlcnp/year2/flexible-plug-and-play/Documents1/Flexible_Plug_Play_Project_Progress_Report_Dec2012.pdf.

[91] G. Manhangwe, C. Marantes, and S. Georgiopoulos, "Flexible plug and play low carbon networks: Quadrature Booster trial at 33 kV," *Electricity Distribution (CIRED 2013), 22nd International Conference and Exhibition on*. pp. 1–4, 2013.

[92] Scottish Power Distribution, "Low Carbon Networks Fund Full Submission Pro-forma," 2013. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/46065/arcresubmissioncombined.pdf.

[93] A. R. Ahmadi, C. Foote, G. Ault, R. Johnston, and A. Gooding, "Technical and Commercial Impacts of Active Network Management on Transmission System Operation," in *CIRED Workshop - Rome, 11-12 June 2014*, 2014, no. 0161, pp. 11–12.

[94] Scottish Power Ltd, "Connection Opportunities," 2014. [Online]. Available: http://www.spenergynetworks.co.uk/pages/connection_opportunities.asp. [Accessed: 27-May-2014].

[95] Scottish Power, "SPD DG Heat Maps," 2014. [Online]. Available: http://www.spenergynetworks.co.uk/pages/connection_opportunities.asp.

[96] Western Power Distribution, "Lincolnshire Low Carbon Hub." [Online]. Available: http://www.westernpowerinnovation.co.uk/Lincolnshire-Low-Carbon-Hub.aspx. [Accessed: 27-May-2014].

[97] P. Bale, "Six monthly progress report six Reporting period: June 2013 to November 2013," 2013. [Online]. Available: http://www.westernpowerinnovation.co.uk/Documents/Project-Progress-Report-Nov-2013-LLCH.aspx.

[98] Fenix Project, “Fenix Project,” 2009. [Online]. Available: http://www.fenix-project.org/.

[99] I. Kuzle, M. Zdrilic, and H. Pandzic, “Virtual power plant dispatch optimization using linear programming,” in *Environment and Electrical Engineering (EEEIC), 2011 10th International Conference on*, 2011, pp. 1–4.

[100] K. E. Bakari and W. L. Kling, “Fitting distributed generation in future power markets through virtual power plants,” in *European Energy Market (EEM), 2012 9th International Conference on the*, 2012, pp. 1–7.

[101] EU EcoGrid, “EU EcoGrid,” 2014. [Online]. Available: www.eu-ecogrid.net. [Accessed: 23-Jun-2014].

[102] EU EcoGrid, “EcoGrid EU : From Design to Implementation,” 2013. [Online]. Available: http://www.eu-ecogrid.net/documents-and-downloads.

[103] ESB National Grid, “Options for Operational Rules to Curtail Wind Generation,” 2004.

[104] Keith Bell, Richard Green, Ivana Kockar, Graham Ault, Jim McDonald, and Gas and Electricity Markets Authority, “Project TransmiT: Academic Review of Transmission Charging Arrangements,” University of Strathclyde & University of Birmingham , 2011.

[105] National Grid, “The Grid Code,” 2014. [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/.

[106] CIGRE Working Group C6.09, “Demand Side Integration,” CIGRE, 2011.

[107] B. Kuri and F. Li, “Effective design for competitive electricity markets,” *Universities Power Engineering Conference, 2004. UPEC 2004. 39th International*, vol. 3. pp. 1034–1038 vol. 2, 2004.

[108] G. Thomas, “Electricity market design and creation in the Asia Pacific region.,” *Power Econ.*, vol. 5, no. 6, p. 24, Jun. 2001.

[109] P. Cramton, “Electricity market design: the good, the bad, and the ugly,” *System Sciences, 2003. Proceedings of the 36th Annual Hawaii International Conference on*. p. 8 pp., 2003.

[110] H. Zhou, Z. Tu, S. Talukdar, and K. C. Marshall, “Wholesale electricity market failure and the new market design,” *Power Engineering Society General Meeting, 2005. IEEE*. pp. 503–508 Vol. 1, 2005.

[111] L. Maurer and L. Barroso, “Electricity Auctions,” 25-Jul-2011. [Online]. Available: http://elibrary.worldbank.org/content/book/9780821388228.

[112] S. Stoft, “Market Structure,” in *Power System Economics: Designing Markets for Electricity*, Wiley-IEEE Press, 2002, pp. 74–81.

[113] SEMO, "SEMO," 2013. [Online]. Available: http://www.sem-o.com/Pages/default.aspx. [Accessed: 09-Sep-2013].

[114] A. Wang and B. Ramsay, "Prediction of system marginal price in the UK Power Pool using neural networks," *Neural Networks,1997., International Conference on*, vol. 4. pp. 2116–2120 vol.4, 1997.

[115] C. K. Simoglou, P. N. Biskas, and A. G. Bakirtzis, "Effect of increased RES penetration on the system marginal price of the Greek electricity market," *Energy Market (EEM), 2010 7th International Conference on the European*. pp. 1–6, 2010.

[116] Y. Chen, X. Xiao, and Y. Song, "The Short-term Forecast of System Marginal Price Based on Artificial Neural Network," *Industrial and Information Systems, 2009. IIS '09. International Conference on*. pp. 70–73, 2009.

[117] Q. Ding, J. Tang, and J. Liu, "Application of new FCMAC neural network in power system marginal price forecasting," *Power Engineering Conference, 2005. IPEC 2005. The 7th International*. pp. 1–57, 2005.

[118] B. Kim, J. P. Velas, J. Lee, J. Park, J. Shin, and K. Y. Lee, "Short-Term System Marginal Price Forecasting Using System-Type Neural Network Architecture," *Power Systems Conference and Exposition, 2006. PSCE '06. 2006 IEEE PES*. pp. 1753–1758, 2006.

[119] J. Saebi, H. Taheri, J. Mohammadi, and S. S. Nayer, "Demand bidding/buyback modeling and its impact on market clearing price," *Energy Conference and Exhibition (EnergyCon), 2010 IEEE International*. pp. 791–796, 2010.

[120] D. S. Kirschen and G. Strbac, *Fundamentals of Power System Economics*. Wiley-Blackwell, 2004, p. 296.

[121] F. Careri, C. Genesi, S. Member, P. Marannino, M. Montagna, and S. Rossi, "Bidding Strategies in Day-Ahead Energy Markets : System Marginal Price vs . Pay as Bid," in *Energy Market (EEM), 2010 7th International Conference on the European*, 2010, no. March, pp. 1–7.

[122] A. Mozdawar and B. Khaki, "Strategic bidding in pay as bid power market by combined probabilistic and game theory procedures," *PowerTech, 2009 IEEE Bucharest*. pp. 1–6, 2009.

[123] Y. Ren and F. D. Galiana, "Pay-as-bid versus marginal pricing-part I:Strategic generator offers," *Power Systems, IEEE Transactions on*, vol. 19, no. 4. pp. 1771–1776, 2004.

[124] Y. Ren and F. D. Galiana, "Pay-as-bid versus marginal pricing-part II: market behavior under strategic Generator offers," *Power Systems, IEEE Transactions on*, vol. 19, no. 4. pp. 1777–1783, 2004.

[125] A. E. Kahn, P. C. Cramton, R. H. Porter, and R. D. Tabors, "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?," 2001.

[126] F. Stacke and P. Cuervo, “Integrated Pool/Bilateral/Reserve market operation under pay-as-bid pricing,” *Electricity Market, 2008. EEM 2008. 5th International Conference on European*. pp. 1–8, 2008.

[127] F. Milano, “Power system modelling and scripting,” *Power Systems*. Springer, London, 2010.

[128] Q. Zhifeng, G. Deconinck, and R. Belmans, “A literature survey of Optimal Power Flow problems in the electricity market context,” in *Power Systems Conference and Exposition, 2009. PSCE ’09. IEEE/PES*, 2009, pp. 1–6.

[129] M. J. Dolan, E. M. Davidson, I. Kockar, G. W. Ault, and S. D. J. McArthur, “Distribution Power Flow Management Utilizing an Online Optimal Power Flow Technique,” *Power Syst. IEEE Trans.*, vol. PP, no. 99, p. 1, 2012.

[130] M. J. Dolan, E. M. Davidson, G. W. Ault, F. Coffele, I. Kockar, and J. R. McDonald, “Using optimal power flow for management of power flows in active distribution networks within thermal constraints,” in *Universities Power Engineering Conference (UPEC), 2009 Proceedings of the 44th International*, 2009, pp. 1–5.

[131] T. Boehme, G. P. Harrison, and A. R. Wallace, “Assessment of distribution network limits for non-firm connection of renewable generation,” *Renew. Power Gener. IET*, vol. 4, no. 1, pp. 64–74, 2010.

[132] Z. Guoqiang, Z. Boming, S. Hongbin, and W. Wenchuan, “Ultra-short term probabilistic transmission congestion forecasting considering wind power integration,” in *Advances in Power System Control, Operation and Management (APSCOM 2009), 8th International Conference on*, 2009, pp. 1–6.

[133] A. Dimitrovski and K. Tomsovic, “Boundary load flow solutions,” *Power Syst. IEEE Trans.*, vol. 19, no. 1, pp. 348–355, 2004.

[134] X. Wang, Y. H. Song, and Q. Lu, “Primal-dual interior point linear programming optimal power flow for real-time congestion management,” in *Power Engineering Society Winter Meeting, 2000. IEEE*, 2000, vol. 3, pp. 1643–1649 vol.3.

[135] X. Wang, Y. H. Song, and Q. Lu, “Lagrangian decomposition approach to active power congestion management across interconnected regions,” *Gener. Transm. Distrib. IEE Proceedings-*, vol. 148, no. 5, pp. 497–503, 2001.

[136] B. Singh, R. Mahanty, and S. P. Singh, “A decentralized congestion management using interior point method,” in *Power and Energy Society General Meeting, 2011 IEEE*, 2011, pp. 1–7.

[137] J. Hazra and D. P. Seetharam, “A network congestion management approach considering the risk of cascading failures,” in *Power Electronics, Drives and Energy Systems (PEDES) & 2010 Power India, 2010 Joint International Conference on*, 2010, pp. 1–7.

[138] J. Hazra, A. K. Sinha, and Y. Phulpin, “Congestion management using generation rescheduling and/or load shedding of sensitive buses,” in *Power Systems, 2009. ICPS ’09. International Conference on*, 2009, pp. 1–5.

[139] Z. Wang, C. W. Yu, A. K. David, C. Y. Chung, and C. T. Tse, “Transmission congestion management in restructured electricity supply system,” in *Advances in Power System Control, Operation and Management, 2000. APSCOM-00. 2000 International Conference on*, 2000, vol. 1, pp. 215–219 vol.1.

[140] M. Moghaddam, H. Abdi, and M. Javidi, “Transmission Expansion Planning in Competitive Electricity Markets Using AC OPF,” *2006 IEEE PES Power Syst. Conf. Expo.*, pp. 1507–1512, 2006.

[141] D. Chattopadhyay and J. Momoh, “A multiobjective operations planning model with unit commitment and transmission constraints,” *Power Systems, IEEE Transactions on*, vol. 14, no. 3. pp. 1078–1084, 1999.

[142] S. W. Alnaser and L. F. Ochoa, “Distribution network management system: An AC OPF approach,” *Power and Energy Society General Meeting (PES), 2013 IEEE*. pp. 1–5, 2013.

[143] E. Naderi, H. Seifi, and M. S. Sepasian, “A Dynamic Approach for Distribution System Planning Considering Distributed Generation,” *Power Delivery, IEEE Transactions on*, vol. 27, no. 3. pp. 1313–1322, 2012.

[144] L. F. Ochoa, C. J. Dent, and G. P. Harrison, “Distribution Network Capacity Assessment: Variable DG and Active Networks,” *Power Syst. IEEE Trans.*, vol. 25, no. 1, pp. 87–95, 2010.

[145] A. Keane, L. F. Ochoa, C. L. T. Borges, G. W. Ault, A. D. Alarcon-Rodriguez, R. A. F. Currie, F. Pilo, C. Dent, and G. P. Harrison, “State-of-the-Art Techniques and Challenges Ahead for Distributed Generation Planning and Optimization,” *Power Systems, IEEE Transactions on*, vol. 28, no. 2. pp. 1493–1502, 2013.

[146] P. N. Vovos, G. P. Harrison, A. R. Wallace, J. W. Bialek, and A. Definitions, “Optimal Power Flow as a Tool for Fault Level-Constrained Network Capacity Analysis,” vol. 20, no. 2, pp. 734–741, 2005.

[147] C. J. Dent, L. F. Ochoa, and G. P. Harrison, “Network Distributed Generation Capacity Analysis Using OPF With Voltage Step Constraints,” *Power Systems, IEEE Transactions on*, vol. 25, no. 1. pp. 296–304, 2010.

[148] H. Wei, H. Sasaki, J. Kubokawa, and R. Yokoyama, “Large scale hydrothermal optimal power flow problems based on interior point nonlinear programming,” *Power Systems, IEEE Transactions on*, vol. 15, no. 1. pp. 396–403, 2000.

[149] S. Gill, I. Kockar, and G. W. Ault, “Dynamic Optimal Power Flow for Active Distribution Networks,” *Power Systems, IEEE Transactions on*, vol. 29, no. 1. pp. 121–131, 2014.

[150] A. Castillo and D. F. Gayme, "Profit maximizing storage allocation in power grids," *Decision and Control (CDC), 2013 IEEE 52nd Annual Conference on*. pp. 429–435, 2013.

[151] A. L. Costa and A. S. Costa, "Energy and ancillary service dispatch through dynamic optimal power flow," *Power Tech Conference Proceedings, 2003 IEEE Bologna*, vol. 4. p. 7 pp. Vol.4, 2003.

[152] L. B. Cunningham, R. Baldick, and M. L. Baughman, "An empirical study of applied game theory: transmission constrained Cournot behavior," *Power Syst. IEEE Trans.*, vol. 17, no. 1, pp. 166–172, 2002.

[153] T. Pinto, Z. A. Vale, H. Morais, I. Praca, and C. Ramos, "Multi-agent based electricity market simulator with VPP: Conceptual and implementation issues," in *Power & Energy Society General Meeting, 2009. PES '09. IEEE*, 2009, pp. 1–9.

[154] I. Praca, C. Ramos, Z. Vale, and M. Cordeiro, "MASCEM: a multiagent system that simulates competitive electricity markets," *Intell. Syst. IEEE*, vol. 18, no. 6, pp. 54–60, 2003.

[155] R. D. Zimmerman, "PowerWeb," 2004. [Online]. Available: http://www.pserc.cornell.edu:8082/powerweb/.

[156] R. D. Zimmerman, C. E. Murillo-Sánchez, and R. J. Thomas, "MATPOWER: Steady-State Operations, Planning, and Analysis Tools for Power Systems Research and Education," *Power Syst. IEEE Trans.*, vol. 26, no. 1, pp. 12–19, 2011.

[157] MATLAB, "MATLAB." The MathWorkds Inc., Natick, Massachusetts, 2013.

[158] F. Milano, "PSAT," 2011. [Online]. Available: http://faraday1.ucd.ie/psat.html. [Accessed: 04-May-2015].

[159] PowerWorld Corporation, "PowerWorld Simulator," 2012. [Online]. Available: http://www.powerworld.com/products/simulator.asp.

[160] Siemens, "PSS/E Product Suite," 2012. [Online]. Available: http://www.energy.siemens.com/us/en/services/power-transmission-distribution/power-technologies-international/software-solutions/pss-e.htm.

[161] Ofgem, "Feed-in Tariff Payment Rate Table for Non-Photovoltaic Eligible Installations for FIT Year 4 (1 April 2013 to 31 March 2014)," 2013. [Online]. Available: http://www.ofgem.gov.uk/Sustainability/Environment/fits/tariff-tables/Documents1/FIT Tariff Table 1 April 2013 Non-PV Only.pdf.

[162] Ofgem, "Climate Change Levy examption." [Online]. Available: https://www.ofgem.gov.uk/environmental-programmes/climate-change-levy-exemption. [Accessed: 07-May-2014].

[163] HMRC, "Climate Change Levy rates from 1 April 2014," 2014. [Online]. Available: http://customs.hmrc.gov.uk/channelsPortalWebApp/channelsPortalWebApp.portal

?_nfpb=true&_pageLabel=pageExcise_ShowContent&id=HMCE_PROD1_031183&propertyType=document. [Accessed: 07-May-2014].

[164] R. Macdonald and C. Foote, "Constraint Analysis Techniques for Active Networks," in *CIRED 22nd International Conference of Electricity Distribution*, 2013, no. 0614, pp. 10–13.

[165] L. Kane and G. Ault, "Evaluation of Wind Power Curtailment in Active Network Management Schemes," *IEEE Trans. Smart Grids*, p. 8.

[166] European Environment Agency, "Europe's onshore and offshore wind energy potential," 2009. [Online]. Available: http://www.eea.europa.eu/publications/europes-onshore-and-offshore-wind-energy-potential.

[167] EMEC, "EMEC - European Marine Energy Centre Ltd.," 2014. [Online]. Available: http://www.emec.org.uk/. [Accessed: 20-Aug-2014].

[168] RenewableUK, "UKWED Operational Wind Farms," 2011. [Online]. Available: http://www.bwea.com/ukwed/operational.asp.

[169] D. Sinclair, Y. Hills, E. C. Eyre, G. Ault, C. Foote, L. Kane, C. Allen, and E. Kearney, "Actively Managed Distribution and the BSC - Final Report," 2014.

[170] National Grid, "Transmission Network Use of System Charges," 2014. [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-network-use-of-system-charges/. [Accessed: 19-Oct-2014].

[171] H. Snodin, "Scottish Islands Renewable Project - Grid Access Study," 2014. [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/306497/REP_1374_001_001E_Islands_grid_access.pdf.

[172] SSEPD, "Scottish Hydro Electric Power Distribution plc Use of System Charging Statement Effective from 1st April 2013," 2013.

[173] Scottish Power Distribution, "Schedule of Final Charges and Other Tables April 14-15," 2014. [Online]. Available: http://www.scottishpower.com/pages/connections_use_of_system_and_metering_services.asp.

[174] Ofgem, "Electricity System Operator Incentives : Incentives from 2015," 2015. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/88216/extensionconsultationjune2014final.pdf.

[175] Ofgem, "Understanding Energy Bills," 2014. [Online]. Available: https://www.ofgem.gov.uk//information-consumers/domestic-consumers/understanding-energy-bills. [Accessed: 11-Oct-2014].

[176] Ofgem, “Transition to Smart Meters,” 2014. [Online]. Available: https://www.ofgem.gov.uk/electricity/retail-market/metering/transition-smart-meters. [Accessed: 11-Oct-2014].

[177] Ofgem, “Market Review,” 2014. [Online]. Available: https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/retail-market-review. [Accessed: 11-Oct-2014].

[178] SSEPD, “Connecting Orkney : Electricity Network Reinforcement Stakeholder Consultation,” 2014. [Online]. Available: http://news.ssepd.co.uk/media/109605/4275_sse_orkney_consultation_l10.pdf.

[179] SSEPD, “Shetland,” 2014. [Online]. Available: http://www.ssepd.co.uk/Shetland/. [Accessed: 11-Oct-2014].

[180] E. Norris, “Ofgem Low Carbon Network Fund Project Progress Report - Accelerating Renewable Connections,” 2013.

[181] E. Norris, “Ofgem Low Carbon Network Fund Project Progress Report,” 2014.

[182] Smart Grid Forum - Work Stream Six, “Minutes of Meeting 27,” 2014. [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/89678/070814ws6minutes.pdf.

[183] National Grid, “Connection and Use of System Code,” 2012. [Online]. Available: http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/.

[184] Ofgem, “Innovation,” 2012. [Online]. Available: http://www.ofgem.gov.uk/Networks/Techn/NetwrkSupp/Innovat/Pages/Innvtion.aspx.

[185] Ofgem, “Low Carbon Networks Fund,” 2012. [Online]. Available: http://www.ofgem.gov.uk/networks/elecdist/lcnf/pages/lcnf.aspx.

[186] SSEPD, “Orkney Active Network Management Scheme : Enterprise Architect Models,” 2012. [Online]. Available: www.ssepd.co.uk/WorkArea/DownloadAsset.aspx?id=993.

[187] Object Management Group Inc, “Business Process Modelling Notation,” 2014. [Online]. Available: http://www.omg.org/bpmn/.

[188] L. Kane and G. Ault, “A review and analysis of renewable energy curtailment schemes and Principles of Access: Transitioning towards business as usual,” *Energy Policy*, vol. 72, pp. 67–77, May 2014.

[189] SSEPD, “Projects and Innovation,” 2014. [Online]. Available: https://www.ssepd.co.uk/Innovation/.

[190] National Grid, “Balancing Services Contracts Information Pack,” 2012. [Online]. Available: http://www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/.

[191] Smart Grid Forum - Work Stream Six, “Minutes from Meeting 25 – Smart Grid Forum Work Stream Six,” 2014.

[192] Ofgem, “Working Documents - Work Stream Six,” 2014. [Online]. Available: https://www.ofgem.gov.uk/publications-and-updates/working-documents-work-stream-six. [Accessed: 11-Oct-2014].

[193] A. Laguna Estopier, S. Georgipolous, E. Crosthwaite Eyre, and C. Marantes, “Flexible Plug and Play Low Carbon Networks: Commercial Solutions For Active Network Management,” in *22nd International Conference on Electricity Distribution, Stockholm*, 2013, p. 4.