DEPARTMENT OF ELECTRONIC & ELECTRICAL ENGINEERING

University of Strathclyde Engineering

Maximising the benefit of distributed wind generation through intertemporal Active Network Management

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

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March 2014

To Sue…Sorry it's not a bike

Shetland

Acknowledgements

I would like to particularly acknowledge Graham Ault and Ivana Kockar for their excellent help as supervisors. The Centre for Doctoral Training in Wind Energy Systems has provided a fantastic environment in which to work. I would like to thank Bill Leithead, David Infield and Drew Smith for helping me complete my research, as well as other members of the CDT.

The work presented in Chapter 7 represents my contribution to the NINES Active Network Management project. I would like to thank members of the Strathclyde NINES team, particularly: Mike Dolan, Katalin Svehla, Laura Kane, Graeme Hawker, Keith Bell and Tom Houghton. I would also like to acknowledge both Scottish Hydro Electric Power Distribution and Smarter Grid Solutions for the use data and access to their expertise.

And thank you to Sue for all her support over the past three years.

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Abstract

The role of distribution networks is changing. There is a significant drive, influenced by climate change and security of supply issues, to move electricity generation towards renewable technologies. This is leading to an increase in demand for renewable generation connections at the distribution network level and putting pressure on distribution network operators to change the 'fit-and-forget' philosophy of network operation to include more active approaches. In the UK this is seen through the development of Active Network Management schemes which manage distributed generation in real-time, applying constraints when required to maintain network limits.

In parallel, technologies have been developed that are capable of providing intertemporal flexibility, of which two particular examples are energy storage and flexible demand.

The objective of the thesis is to answer the questions: How can energy storage and flexible demand be scheduled in a second-generation Active Network Management scheme? And how should they be operated to gain most benefit from distributed wind generation?

To answer these questions, the thesis develops and uses tools to study the optimisation of second-generation Active Network Management schemes including intertemporal technologies. The tools developed include a Dynamic Optimal Power Flow algorithm for management of energy storage and flexible demand. The thesis provides the first fully flexible model of energy storage in this context, the first implementation of principles-of-access in an optimal power flow, and the first detailed study of the role of energy storage and flexible demand in managing thermal limits and reducing curtailment of distributed wind generation.

The thesis also develops the theory of Dynamic Locational Marginal Pricing based on the economic information contained in an optimal solution to a Dynamic Optimal Power Flow. The thesis shows this to be a useful way of understanding the economic

impact of intertemporal flexibility and monetary flows in markets which contain them.

The thesis goes on to provide a detailed report of the application of Dynamic Optimal Power Flow and Dynamic Locational Marginal Pricing to an islanded Active Network Management scheme currently in deployment in the UK. This highlights the ability of the tools developed to contribute to future projects.

A conclusions of the thesis is that DOPF provides a useful method of scheduling flexible devices such as energy storage and power systems. It takes full account of network constraints and limitations, and as applied in this thesis, the most complete models of the intertemporal effects of energy storage and flexible demand to date.

The studies contained in the thesis show that energy storage and flexible demand can increase the benefit of distributed wind generation in Active Network Management by minimising curtailment and transferring generated electricity to periods during which the energy has greatest value in offsetting expensive, fossil fuel based generation. The thesis notes the importance of a useful definition of the 'benefit' of wind generation in terms of global objectives such as minimising emissions rather than interim objectives such as maximising generation from renewables.

The thesis discusses the importance of losses in energy storage, and the relationship of storage and network losses with curtailment of wind and the lost opportunity of generating electricity. In terms of losses, the extension of existing economic analysis methods leads to the result that flexibility will only operate between time-steps where the ratio of prices is greater than the round-trip losses of the store. Within this constraint, effective use of energy storage is shown to result from regular charging and discharging. The comparison between energy storage and flexible demand shows that where there are few losses associated with flexibility in demand it is significantly more successful than energy storage at mitigating the effects of variability in wind.

The final study of an islanded distribution network with wind curtailment, concludes that energy storage is less effective that flexible demand at reducing wind curtailment, but can provide benefit through management of peak demand. Flexible demand, in the form of flexible domestic electric heating, is shown to have the ability to provide a significant benefit in terms of reduced wind curtailment. This ability is further enhanced for island situations if demand has a frequency-responsive component.

Abbreviation list

ANM	Active Network Management
DDSM	Domestic Demand Side Management
DHN	District Heating Network
DLMP	Dynamic Locational Marginal Pricing
DMS	Dynamic Merchandising Surplus
DNO	Distribution Network Operator
DOPF	Dynamic Optimal Power Flow
FITS	Feed-in tariffs
LIFO	Last In First Out
LMP	Locational Marginal Pricing
LPS	Lerwick Power Station
NINES	Northern Isles New Energy Solutions
NPV	Net Present Value
OPF	Optimal Power Flow
ROCs	Renewable Obligation Certificates
SHEAP	Shetland Heat Energy And Power (Operator of the Lerwick district heating network)
SHEPD	Scottish Hydro Energy Power Distribution
SVT	Sullom Voe Terminal

Chapter 1: Introduction

SMART GRID is one of the most frequently used terms in the academic literature about power systems. During the period January 2010 – May 2013, 919 journal and magazine articles were published by the IEEE containing Smart Grid as a key word [1.1]. A specific journal, *IEEE Transactions on Smart Grids*, was launched in 2010 [1.2] and in the first edition's editorial the smart grid concept is described as follows:

> Smart grid represents a vision for digital upgrade of electric power systems. It optimizes grid operations, enhances grid security, and opens new markets for the utilization of sustainable energy. [1.3]

This description highlights the novelty of the techniques and technology required to operate the future grid. Smart Grid is predicated on the need for the power system to help achieve greater utilisation of sustainable energy sources whilst maintaining safe and secure operation of the grid. The concept of smart grid is about managing power systems to meet the energy needs of our future society.

1.1 The challenge of the future energy system

Any energy system should be designed to accomplish the energy goals set by the society which it serves. In many countries, the aims of their current energy policy combines aspects of three competing objectives which together lead towards sustainability: low-carbon generation; security of supply; and the lowering of costs.

These three have inherent tensions - and attempts to optimise the system according to one objective is often at the expense of meeting the other two. The tensions are illustrated by *the energy trilemma* [1.4] illustrated in Figure 1.

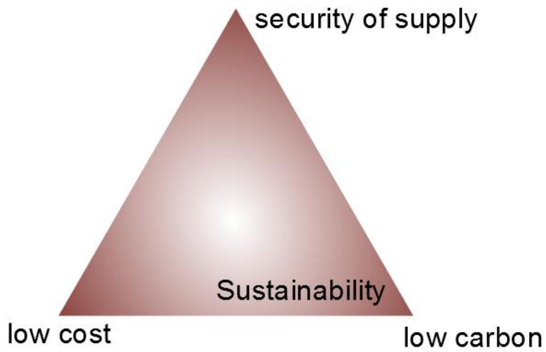

Figure 1 : The energy trilemma showing the three competing objectives of modem energy policy which lead towards a sustainable system (adapted from [1.4]).

Low-carbon technologies include wind generation, nuclear or fossil fuel generation fitted with carbon capture. The associated costs are higher than those of traditional carbon-intensive technologies: in the UK context the levelised cost of onshore and round three offshore wind generation is estimated at approximately £90/MWh and £113/MWh respectively; this compares with £85/MWh for closed-cycle gas turbines [1.5].

The third horn of the trilemma – security of supply – includes both the day-to-day operational security of energy infrastructure and longer term issues regarding fuel prices and availability. Wind generation, as an example of an intermittent renewable technology is likely to reduce the operational security of a power system due to the uncertainty of its operation. However, in the longer term the availability of wind generation in the UK is considerably more certain than the price or availability of fossil fuels and nuclear fuels purchased in the geopolitical market.

Finding a balance between the competing objectives of the energy trilemma is a challenge faced by energy policy makers in many countries. In most instances, renewable generation, particularly wind and solar generation, form a key part of those policies. The European Union has a target of generating 20% of energy from renewable sources by 2020 [1.6], which includes a 15% target for the UK [1.7]. As renewable electricity generation is more mature than renewable heat or transport, it is expected that this will provide the greatest contribution to meeting those targets. The UK Government expects that 30% of the UK's electricity will be generated by renewables by 2020, compared with 12% of heat and 10% of transport energy [1.7]. Within the UK, Scotland has put in place the most stringent renewable targets, aiming for 100% of electricity demand to be met by renewable energy when averaged across a year [1.8].

These targets highlight the important role that the electrical networks will play in connecting, distributing and facilitating the use of electricity from onshore wind generation. The UK Government's Renewable Energy Roadmap estimates that onshore wind capacity will increase to 13GW in 2020 [1.9]. The role of the electricity networks is to ensure that this energy is available to meet demand for electricity where and when it is required whilst maintaining safety.

1.2 Distribution networks and distributed wind generation

Traditionally, distribution networks have been designed to take power from the point of connection with the transmission network and deliver it to consumers - power flow has been outwards. This design formed part of a power system with a small number of large, centrally located and controllable generators.

The expansion of renewable generation changes both the character and the location of generation. Generation from wind farms is intermittent and significantly less controllable than conventional fossil fuel generation. In addition, a significant capacity of wind generation is connected to the distribution rather than the transmission network. Connecting wind generation as distributed generation (connected to the distribution network) is advantageous because it entails significantly lower costs for small-scale developments and in many locations it is the *only* power system infrastructure.

Figure 2 shows the wind resource of the UK. Areas of high wind resource are generally towards the northern and western fringes in Scotland, western England and Wales. These are the areas that are poorly served by the transmission network, and wind farms developed in these areas have no choice but to connect to the distribution network.

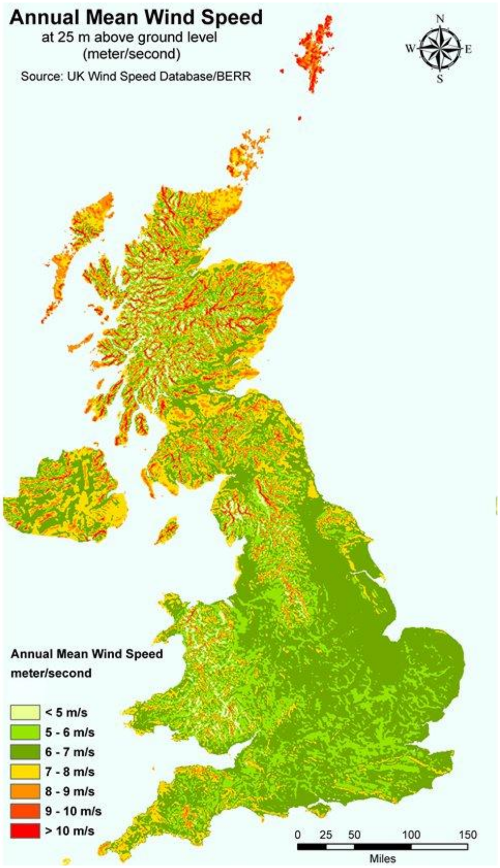

Figure 2: Wind resource map of the UK[1]

Whilst there is high demand for distribution-level connections for generation in these areas, capacity on distribution networks is limited. Passive operation of distribution networks has until recently been the norm, and this significantly limits the capacity of wind generation that can be connected. Distribution Network Operators (DNOs) define a *firm limit* on the capacity of distributed generation. This is calculated using

[1] Taken from: https://restats.decc.gov.uk/cms/annual-mean-wind-speed-map

the worst-case operating conditions for the network. Because distribution networks were designed to operate autonomously without direct control from the operator, it was considered important that distributed generation did not lead to the violation of either voltage or thermal limits at any demand level that might be expected on the distribution network. As such, DNOs identify the condition during which the least distributed generation is possible - and define this as the limit on the distributed *capacity* that they will connect. The worst-case scenario is usually the minimum demand [1.10, 1.11]. Figure 3 illustrates the flow of real power from a distributed generator (either to a local demand or up the distribution network towards the transmission network). The maximum allowable output of a distributed generator is equal to the local demand and the thermal limit on the distribution branch.

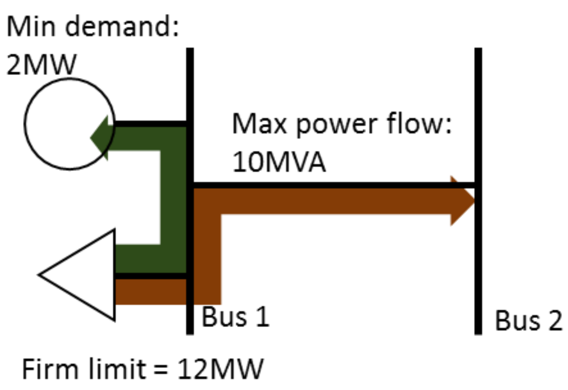

Figure 3: Definition of the firm limit on distributed generation capacity. As power flow limits are normally quoted in MVA to represent apparent power, it is assumed here that reactive power flows are negligible.

As well as thermal limits, the addition of distributed generation leads to a voltage rise effect, where voltage at the point of connection is increased so that power flows back up the distribution network. In some circumstances, again when local demand is low, voltage at the point of connection can reach its upper bound and act to limit capacity.

The firm limit is important for the secure operation of a passive distribution network, however with modern communications and control technology it is excessively rigid. The limit is binding only during the small fraction of a year where demand is close to its minimum, and only if all distributed generation is at its maximum output at the same time. The intermittency of wind generation further reduces the times that the firm limit is binding.

The move to *active* operation of distribution networks has been developed over the past decade in the UK through Active Network Management (ANM). This allows an increased capacity of distributed generation to connect under the condition that its output is curtailed when required, to maintain thermal and voltage limits. This new wind is connected under *non-firm* contracts which do not guarantee network access at all times. Curtailment schemes involving non-firm distributed generation have been deployed, or are in the process of being deployed, on a number of distribution networks across the UK.

The introduction of non-firm wind generation increases the capacity of renewable generation on the power system. But each unit of non-firm capacity provides less benefit because some of its potential output is curtailed. Gaining the greatest benefit from non-firm wind generation involves minimising curtailment. Two methods of achieving this are: time-shifting otherwise curtailed generation by using energy storage; and the use of flexible demand which can be scheduled to use otherwise curtailed generation.

Both these technologies are being rolled out on UK distribution networks during 2013. On the Orkney distribution network, the UK's first large-scale battery was commissioned during August 2013 [1.12]. On the Shetland Islands, a flexible electric heating project is underway with a local housing association [1.13].

Energy storage and flexible demand are both technologies which can be designated as *intertemporal*. That is, their operation needs to be planned across time, with decisions on how to operate at one point in time affecting the ability to operate at other points in time. For example, with energy storage, charging the store now reduces the ability to charge it later. Because management of these technologies needs advanced planning, ANM will need to move beyond the real-time monitor-and-control methods used in curtailment schemes. Schemes with intertemporal technologies will need to employ an element of scheduling (weather explicit or implicit) for those technologies, in advance of operation. The introduction of intertemporal technologies with the requirement of scheduling form part of a move identified in this thesis towards *second-generation ANM schemes.*

1.3 Focus of the thesis

This thesis focuses on the need to develop optimisation tools capable of modelling both the network effects and the intertemporal effects of second-generation ANM schemes. The focus is on the needs identified from existing and planned ANM schemes in the UK, particularly those on the Orkney and Shetland Islands. Energy storage and flexible demand are used as two examples of intertemporal flexibility. The methodological frameworks developed are general and can include many technologies relevant to ANM schemes; a subset of these technologies are modelled in the case studies, and the focus is on issues identified in the review of literature as requiring development. The case studies focus on: curtailment due to thermal constraints; the operation of non-firm wind; energy storage; and flexible demand. The role of other ANM technologies such as coordinated voltage control and reactive power dispatch, which are well developed by the existing literature, are also discussed.

1.4 Thesis objectives

The main question this thesis attempts to answer is:

- How can energy storage and flexible demand be scheduled in a second-generation ANM scheme? How should they be operated to gain the most benefit from distributed wind generation?

Answering this question requires the development of several tool and techniques which will model the optimisation of Active Network Management schemes. It also entails defining what is meant by 'benefit from distributed wind'. Finally these tools and techniques will be applied to a case study based on the ANM scheme currently in development on the Shetland Islands.

To answer the main thesis question, the following objectives are defined:

- Review the existing literature on ANM and active distribution networks; conclude on the likely future development trends.
- Review the optimisation methods currently used for operation of ANM, particularly those based on Optimal Power Flow. Identify the developments required for modelling second-generation ANM, including energy storage and flexible demand.
- Define the benefit delivered by distributed wind generation.
- Develop optimisation tools which can be applied to the operation of non-firm wind generation, energy storage and flexible demand in a distribution network.
- Develop a multi-time-step or Dynamic Optimal Power Flow (DOPF) framework suitable for modelling and optimising the operation of non-firm wind, energy storage and flexible demand.
- Benchmark the benefits provided by non-firm wind generation using the optimisation tools developed.
- Investigate the increase in benefit from distributed wind generation when energy storage and flexible demand are included in a distribution network with the optimisation tools developed.
- Identify the factors important for maximising the benefit provided by such ANM schemes.
- Demonstrate the application of DOPF to an industrial project developing a new ANM scheme.
- Extend the concept of Locational Marginal Prices (LMPs) and the economic signals from optimal power flow solutions to use the results of DOPF; develop a theory of Dynamic Locational Marginal Prices (DLMPs).
- Apply DLMPs to the industrial ANM case study to show how they can be used to analyse the benefits of an optimally-dispatched ANM scheme.

1.5 Contributions to knowledge

The thesis delivers a number of important contributions to engineering in terms of both knowledge and novel techniques:

1. It provides the first study of the effect of energy storage on the operation of an ANM scheme. This includes the effect of energy storage on other network participants, particularly how it affects the access to the network given to non-firm generators. It is also the first study to consider the influence of renewable subsidies on the siting and operation of energy storage (Chapter 4).
2. The development of a multi-time-step DOPF framework capable of modelling key second-generation Active Network Management technologies. The reframing of energy storage and flexible demand as branches within that network carrying out a similar role to electric circuits: transferring energy between network nodes with the nodes connected by these technologies separated by time rather than space (Chapter 5).
3. The realisation of full models of the following technologies within that framework: energy storage; flexible demand; principles-of-access for non-firm wind generation (Chapter 5).
4. The first fully flexible formulation of energy storage including:
   - The ability to set charging and discharging efficiencies separately at any value between 0 and 1 whilst at the same time removing the need to pre-define times for charging and discharging (Chapter 5).
5. The theory of Dynamic Locational Marginal Prices as an extension of the existing theory of Locational Marginal Prices, and an example of its application to an islanded distribution network (Chapters 6 and 7).
6. The presentation of an operational application of DOPF to an islanded distribution network. This includes extending the model to incorporate limits imposed due to frequency stability issues and modelling individual technical and heuristic operating principles of the distribution network operator (Chapter 7).

1.6 Publications arising from this thesis

Through the development of this thesis, the author has published the following journal articles as main author:

S. Gill, I. Kockar, G. Ault, Dynamic Optimal Power Flow for Active Distribution Networks, *Power Systems, IEEE Transactions on,* vol. 29, no. 1, pp, 121 – 131, Jan 2014.

S. Gill, E. Barbour, I. A. G. Wilson, D. Infield, "Maximising revenue for non-firm distributed wind generation with energy storage in an active management scheme", *Renewable Power Generation, IET,* vol. 7, no. 5, Sep 2013.

S. Gill, B. Stephen, S. Galloway, "Wind Turbine Condition Assessment Through Power Curve Copula Modeling", *Sustainable Energy, IEEE Transactions on*, vol.3, no.1, pp.94-101, Jan. 2012.

S. Gill, M. J. Dolan, D. Frame, G. Ault, "The role of electric heating and district heating networks in the integration of wind energy to island networks", *Distributed Energy Resources, International Journal of,* vol. 7, pp 245-262, July 2011.

The author has also contributed to the following conference papers either as main author or co-author:

B. O'Neill, C. Foot, R. MacDonald, M.J. Dolan, **S. Gill**, C. Mathieson, S. Reid, "Active Network Management on Islanded Systems: The Shetland Experience", *Innovative Smart Grid Technologies (ISGT Europe), 4th IEEE/PES,* Copenhagen, 2013.

I. Kockar, **S. Gill,** "Dynamic Optimal Power Flow for the improved integration of Distributed Energy Resources", *Power and Energy Society General Meeting,* Vancouver, 2013.

S. Gill, G. Ault, I. Kockar, "Using dynamic optimal power flow to inform the design and operation of active network management schemes", *CIRED,* Stockholm, June 2013.

M. J. Dolan, **S. Gill**, G. Ault, M. Barnacle, G. Bell, C. Foote, "Modelling and delivery of an active network management scheme for the Northern Isles new energy solutions project", *CIRED,* Stockholm, June 2013.

L. Kane, G. Ault, **S. Gill,** "An assessment of principles of access for wind generation curtailment in active network management schemes", *CIRED,* Stockholm, June 2013.

S. Gill, G. Ault, I. Kockar, S. Reid, C. Foot, "Operating a wind farm in the future smart grid - lessons from designing and deploying a smart grid on Shetland," *European Wind Energy Association, V*ienna, Jan. 2013.

M. J. Dolan, G. Ault, D. Frame, **S. Gill,** I. Kockar, O, Anaya-Lara, S. Galloway, B. O'Neill, C. Foote, C, 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, 14-17 Oct. 2012,* Berlin, 2012.

S. Gill, E. Barbour, I. A. G. Wilson, D, Infield, "Maximising revenue for non-firm distributed wind generation with energy storage in an active management scheme", *Renewable Power Generation (RPG 2011), IET Conference on, Sept. 2011,* Edinburgh, 2012.

S. Gill, G. Ault, I. Kockar, "The optimal operation of energy storage in a wind power curtailment scheme," *Power and Energy Society General Meeting, 2012 IEEE* , pp.1,8, San Diego, 2012.

A magazine article has also been published in which the author was main author:

S. Gill, L. Kane, D. Infield, B. Leithead, A. McDonald, "Training Tornado: An intensive, cross-curricular Ph.D. Program in Wind Engineering at the University of Strathclyde", *Power and Energy Magazine,* Vol. 11, no. 1, pp 51-57, Jan 2013.

1.7 Summary of the thesis

The structure of this thesis mirrors the development of the concepts – from initial scoping, through development of the underpinning theory, to deployment to a real project.

Chapter 2 provides a review of the academic literature and on-the-ground developments in ANM in the UK. It also discusses two international examples of active distribution networks. It identifies that whilst the first generation of ANM is becoming business-as-usual, a second-generation ANM concept can be identified which includes intertemporal technologies such as energy storage and flexible demand.

Chapter 3 reviews the use of optimal power flow to study active distribution networks, energy storage and flexible demand. It identifies the concept of DOPF – initially used for the problem of hydro-thermal coordination – as useful in the analysis of second-generation ANM schemes.

Chapter 4 is a simplified linear programming-based optimisation study of the operation of an ANM scheme containing energy storage. It discusses how the benefit of distributed wind generation will be defined in the thesis. It then studies a distribution network aggregated to a single-bus and linked to the transmission network by a thermally constrained circuit. The study identifies the role of energy storage in increasing the output of non-firm generation whilst acting to maximise its own revenue. The chapter investigates the benefit provided by energy storage, carries out a cost-benefit analysis, and outlines the effect that renewable subsidies will have on decisions regarding both its placement and efficiency.

Chapter 5 presents the full theoretical framework of DOPF for ANM schemes. It formulates a full model of energy storage and flexible demand. It then provides a simple small-scale case study to show its application to a distribution network.

Chapter 6 develops the theory of DLMP using the economic information from optimal DOPF solutions. DLMPs are defined in terms of the marginal cost of meeting demand at a particular location and a particular time. A simple 2-bus network is used to illustrate the concept.

Chapter 7 describes the adaptation and deployment of the DOPF formation to an industrial project developing an ANM scheme for an islanded network. It describes the Northern Isles New Energy Solutions project on Shetland and the role of DOPF within the project. The chapter goes on to give a detailed analysis of a year-long study into operation of non-firm generation, energy storage and flexible demand with the objective of minimising conventional generation on the Shetland Islands. Finally, the chapter extends the analysis to apply DLMPs to the operation of the Shetland network.

Chapter 8 concludes the thesis and brings together the learning from each chapter. It justifies the contributions to knowledge listed above and answers the key thesis question. Finally, important future work is identified.

1.8 References for Chapter 1

[1.1] IEEE, *Search Results for "Smart Grid" journal and magazine articles*, 2013, Available: http://ieeexplore.ieee.org/search/searchresult.jsp?ranges%3D2010_2012_p_Publication_Year%26queryText%3D%22smart+Grid%22&refinements=4291944246&pageNumber=1&resultAction=REFINE accessed: 10/09/2013.

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Chapter 2: Active Network Management and smart distribution networks

ACTIVE NETWORK MANAGEMENT is an instance of the smart grid. It relates to the infrastructure, technology and techniques needed to make electrical distribution networks both dynamic and able to respond to the challenge of distributed generation and changing demand patterns. It moves away from the paradigm of passive *fit-and-forget* distribution networks in which power flows from the transmission network out to the load. It is also a requirement if the capacity of distributed generation is to be increased beyond the firm limit and it is therefore important for the growth of distributed renewable generation, particularly on-shore wind power.

This chapter introduces the concepts and technologies of ANM and puts them within the wider context of the smart grid. It provides a summary of the key technologies and techniques required for ANM, before giving case studies of existing ANM and other smart distribution schemes in the UK and elsewhere.

This chapter also attempts to understand the role of ANM schemes in gaining the greatest benefit from wind generation. Firstly by allowing more distributed wind capacity onto the network, and secondly by managing that generation capacity and other components of smart distribution networks.

The chapter notes that ANM maintains a relatively centralised control infrastructure, with a central controller sending simple instructions to local controllers which are often privately owned. This can be contrasted with international developments in active distribution networks which include examples that take a more distributed approach to control, for example the Olympic Peninsula project's use of variable pricing in the USA [2.1].

Existing ANM schemes such as on the Orkney Islands that operate in real-time by continual monitoring and control of power flows and generator outputs. The chapter identifies that the introduction of intertemporal technologies such as energy storage and flexible demand requires that ANM controllers will need to include the ability to schedule devices ahead of real-time. Such ANM schemes are designated as *second-generation ANM*. This chapter justifies the need to develop tools and techniques suitable for analysing such second-generation ANM schemes.

2.1 Active Network Management: A definition

Distribution networks have traditionally been passively operated. That is, they have contained relatively few controllable devices and those that they do contain require no communications infrastructure. A key reason for this is reliability: a system with fewer complex parts is likely to have less to go wrong with it. Secondly, greater complexity was not required: the role of distribution networks was to transfer power from the transmission network to customers, with power flowing in one direction. Power system engineers, working on the assumption of one-way power flow, have been able to design simple and effective systems to meet this objective.

Active distribution networks by contrast must fulfil a more complex task and will have to be more complex to achieve their aims. Distribution networks can be defined as becoming active when 'DG [distributed generation] units are added to the distribution system leading to bidirectional power flows in the network' ([2.2], page 3). Networks which contain high capacities of distributed generation must be managed through ANM techniques; and these networks should "incorporate flexible and intelligent control with distributed intelligence leading to smart grid or microgrid networks" ([2.2], page 3). This is a change in philosophy for distribution network operation, away from a *fit-and-forget* strategy, where minimal control or intelligence is required for secure operation, towards a strategy of real-time *connect-and-manage* incorporating monitoring and control technologies. It is a requirement if we wish to make greater use of distribution networks for connecting renewable generation.

The term *Active Network Management* itself is regularly used in the UK, although it remains relatively vaguely defined. In [2.3] it is defined as "Pre-emptive operation… to maintain networks within accepted operating parameters".

This broad definition overlaps with network protection and other forms of network automation. It also disregards the fact that ANM should be actively facilitating the meeting of objectives rather than simply maintaining limits. There is a significant difference between ensuring that voltage stays within acceptable bounds, and actively manipulating voltage to ensure the greatest capacity of distributed generation can be connected.

In [2.4] an extended interim definition for ANM is presented. The key aspect is that "ANM is understood to mean systems that operate to take action automatically to maintain networks within their normal operating parameters" ([2.4], page 6). It goes on to specify the difference between protection and ANM: protection is specifically for fault conditions, whereas ANM involves pre-emptive action. The definition discusses the relevance of ANM to distributed generation but does not include it formally in its definition.

In [2.5], active networks are simply defined as a solution to the problems posed by reaching the levels of distributed generation "proposed over the coming years" ([2.5], page i).

Finally, a report on active distribution networks discussed definitions from respondents to a questionnaire [2.6]. From the 8 responses listed, an analysis leads to the following combined definition:

> "Active Distribution Networks (ADNs) have systems in place to control a combination of distributed energy resources (DERs), defined as generators, loads and storage. Distribution system operators (DSOs) have the possibility of managing the electricity using a flexible network topology. DERs take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement." (from [2.6], page 16)

The common factors of these definitions are: (a) the real-time or pre-emptive nature of ANM intervention; (b) the differentiation from protection systems; and (c) the management of constraints.

In this thesis these three common factors are used as a base of a definition but are extended to note explicitly the role that ANM systems can play in meeting network objectives, rather than simply maintaining limits. The initial working definition for current Active Network Management used in this thesis is given in box 1; the definition is revisited at the end of this chapter in light of the future developments of second-generation ANM discussed.

> Active Network Management means the use of any technology or technique applied to a distribution network that involves controlling the operation of network components in response to measurements in real-time to maintain limits and support wider network objectives.

Box 1: Initial Working Definition of Active Network Management used in this thesis.

The technologies used in ANM may vary and this definition is broad enough to ensure that ANM can be used in a range of situations to achieve a wide variety of goals, whether simply constraint management, or more complex goals such as optimisation of a network towards a particular objective. Figure 4 illustrates the position of ANM within the control hierarchy of a distribution network. It shows the overlap with both protection at the lower end and centralised control systems at the higher end (SCADA, Distribution Management System (DMS) or Energy Management Systems (EMS)). The ANM scheme is subordinate to the SCADA/DMS/EMS control system but the overarching ANM decisions are still made by a centralised controller. The control of individual elements is distributed to local controllers for example at the generators which responds to signals from the central controller. In addition, local controllers have fail-safe control actions to implement when communication are lost.

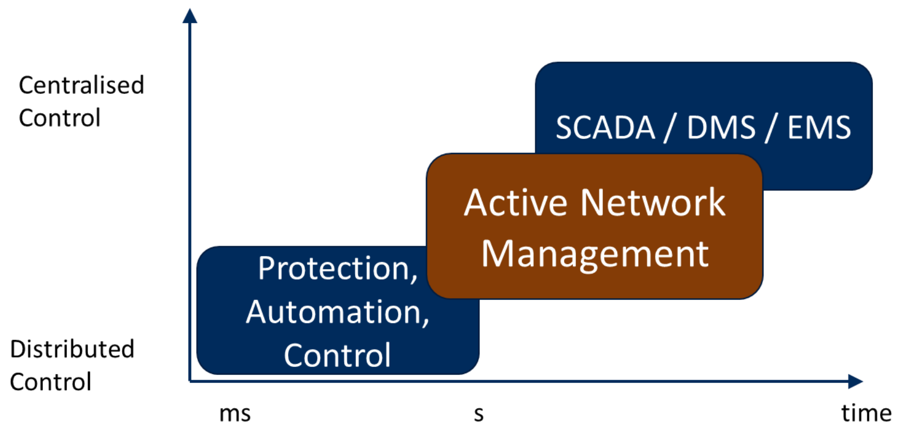

Figure 4: The place of ANM relative to other distribution network control systems (adapted from [2.7])

2.2 Technologies and techniques for Active Network Management

As with any engineering endeavour there is rarely one way to actively manage a network. A particular ANM solution may involve the installation of a specific piece of technology, such as reactive power compensation, a new way of operating an existing piece of hardware such as a transformer, or the introduction of a technique to manage other parts of the network, such as demand.

This section presents the key technologies and techniques that have so far been deployed or proposed, together with others that have the potential to support the ANM philosophy in the future. The techniques covered include: voltage management, generation curtailment, dynamic line ratings, energy storage, direct demand-side management and dynamic pricing. One way to categorise the techniques is as time-independent, and time-dependant. Time-independent techniques are those whose operation at one point in time does not affect operation at other times; conversely time-dependant techniques are those that cannot be operated at one time without consideration of operation at other times.

As noted in the working definition of ANM (Box 1, see section 2.1), schemes require measurement and control systems. Taking measurements across a geographically dispersed system and combining them also requires a robust communications system. These systems: control, measurements, and communication are prerequisites for the deployment of any of the techniques listed below, and are mirrored in other smart grid applications.

Figure 5 shows a generic layout for an ANM system as part of a distribution network. The ANM system combines local and central intelligence. It will control devices either directly or by sending commands to the privately owned control systems of devices connected to the network.

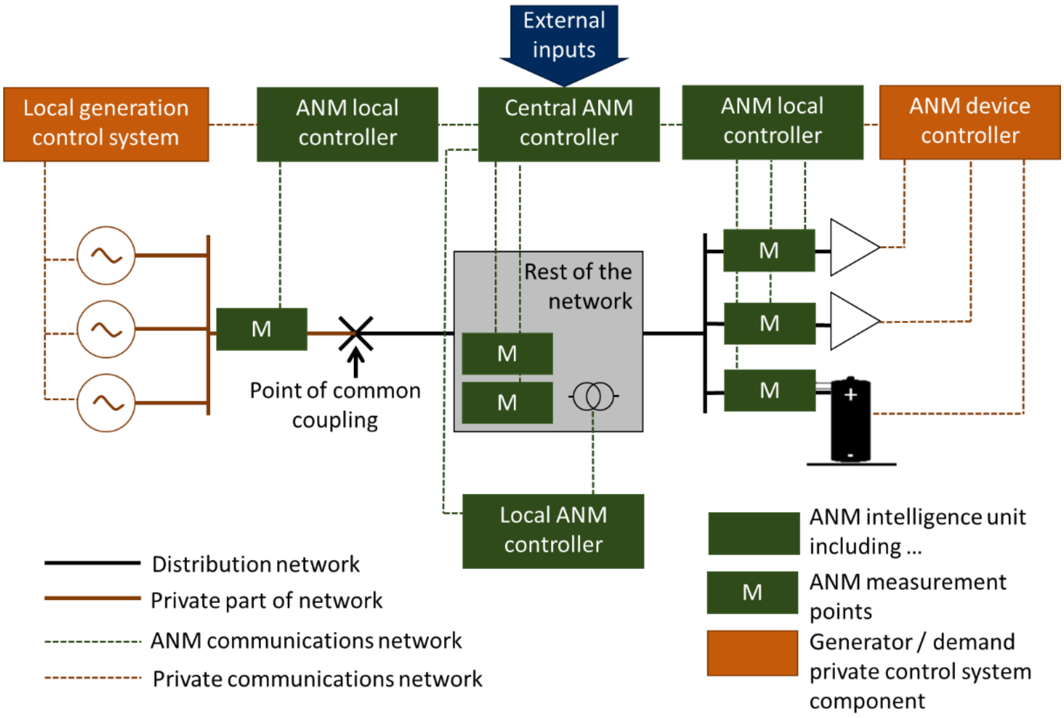

Figure 5: Schematic of the elements required for an ANM scheme as part of a distribution network.

2.2.1 Generation curtailment

Traditionally operated distribution networks have strictly limited capacities of distributed generation. This limit is defined by considering the ability of the distribution network to securely manage the output of all distributed generation *during the worst case scenario and with no intervention.* The worst case situation is generally low demand and full distributed generation output. During these situations two effects tend to limit distributed generation: thermal export limits from the distributed generator; and the voltage rise effect [2.8].

- **Thermal limits:** are created by the finite capacity of overhead lines, cables and transformers for transferring power. The problem is exacerbated by the fact that radial distribution feeders are often tapered, as the quantity of power transferred in a network without distributed generation reduces further along a feeder. This severely limits the capacity of distributed generation that can connect at the extremities.

- **Voltage rise effect:** Power flows from high voltage to low voltage. When built, the design of networks made use of this fact, with voltages set relatively high within the allowed limits in the centre and allowed to drop at the extremities. On load tap changing transformer and voltage regulators can be used to raise the voltage if it drops below the minimum limit at the extremes, however these devices generally have a fixed target voltage on the downstream side and are controlled to maintain this (again to allow outward power flow). Distributed generation leads to power flow up towards the centre, and therefore must raise the voltage at the extremes. Excess generation at the extremes can raise the voltage above allowed limits at the location of the generator, and the voltage rise problem can be made more severe by the action of transformers [2.8, 2.9].

The maximum capacity of firm generation on a distribution network - that is generation that is guaranteed network access at all times - is defined as the maximum injection of power that can be accommodated during minimum demand without breaching voltage and thermal limits. This limits the capacity by considering demand levels that may occur for only a few hours a year. The rest of the time, greater injections of power from distributed generators is possible. When the majority of distributed generation is from wind generation, for long periods the wind generators are not able to generate at full power due to a lack of wind. The average UK capacity factor for on-shore wind generation was 0.27 during 2011 [2.10].

This suggests that with adequate communications and control it may be possible to allow greater distributed generation capacity to be connected, assuming that this generation can be curtailed, if and when required, to maintain thermal and voltage limits.

The reality of implementing a generation curtailment system requires consideration of a variety of issues: communications latency, speed and reliability; speed of response from turbines; the uncontrolled rate of change of demand and generation; and failure to safe state [2.11-2.13].

2.2.1.1 Non-firm contracts and principles of access

The curtailment of distributed generation requires new operating principles. One method of implementing curtailment is through a contract referred to as *non-firm* as it is a contract which does not provide firm network access at all times [2.11]. With multiple non-firm generators, the rules defining which generators receive access to a constrained network must be laid out in a *principle-of-access* which defines the commercial arrangement [2.14].

A number of principles-of-access have been identified for non-firm generators in an ANM scheme, for example in [2.14]. However, only one has been implemented to date: priority order principle-of-access in the form of Last-In-First-Out (LIFO) [2.15]. In [2.16] the following principles for commercial arrangements are listed: they should be safe and secure; equitable and efficient; transparent; feasible and in line with the grid code, distribution codes, and relevant legislation. Some identified principles of access are:

- **Last-In-First-Out:** A priority order method based on the order in which generators connect to the network. Under all circumstances the highest priority generator (the first to connect) receives first access to the network capacity available; once their generation has been absorbed the second highest priority generation (the second to connect) receives access. The level of curtailment increases as priority decreases. There are significant operational benefits to the LIFO scheme: it is simple and transparent; and once connected, generators can be sure that later connecting generators will not affect their network access. However, as noted in [2.17] this method is unlikely to lead to the maximum capacity of distributed generation connecting as late connections will receive very restricted network capacity.

- **Shared Percentage:** A shared percentage scheme ensures that curtailment is equally shared between all generators contributing to a constraint. This has the advantage that no one generator is excessively constrained and it is more likely than LIFO to lead to the maximum viable capacity connecting. However as more generators connect, leading to increased curtailment, existing generators will find their curtailment levels rising. This uncertainty in future network access is likely to be a deterrent to investment.
- **Market-Based Methods:** Network capacity can be considered as an economic good of limited supply. Generators can be required to bid either for access to network (the right to generate) or alternatively to offer to be curtailed. Implementing a market mechanism is likely to find favour within the current climate of liberalised energy markets, however as noted in [2.14] it may be too complex to implement in relatively small scale distribution networks.
- **Technical Best:** A technical best principle-of-access will allow the distribution network operator to define the best way of dispatching the network functioning under the current conditions and to impose that solution on generators. The definition of technical best may include minimisation of losses or most secure operation. Such a principle-of-access has the advantage of providing strong signals to developers as to where to develop - as a generator connected in a location that is often 'technically bad' is likely to receive high levels of curtailment.

The Low Carbon Network Fund project *flexible plug and play* undertaken by UK Power Networks has recently reported on its investigation into principles of access for distributed generators in ANM schemes [2.18]. A number of schemes are studied under the principles that they should be efficient, certain, simple, fair and develop learning ([2.18], page 7). The project compares LIFO with shared percentage, it notes the difficulty created by the shared percentage method is the uncertainty over future curtailment levels, and discusses a number of possibilities for getting around this commercially. It recommends two implementations of shared percentage. Firstly to pre-define a maximum level of curtailment then allow generators to connect until curtailment for all non-firm generators reaches that limit. This limit is defined as the curtailment level at which the cost of curtailment outweighs the cost of network reinforcement. This highlights the role of ANM in deferring reinforcement cost. The second method is a capacity auction in which, once accepted for connection, generators bid for the annual level of curtailment they would be prepared to accept.

The report highlights the difficulty in maintaining the principles of fairness and simplicity and at the same time ensuring efficiency of network use.

2.2.2 Co-ordinated voltage control

Voltage management is a significant issue for all distribution networks. The main method of controlling voltage across a traditional passive distribution network is through on-load-tap-changing transformers which are controlled based on the local voltage. Local voltage control makes use of the assumption of one-way power flow. If this assumption is not valid it significantly reduces the usefulness of local voltage control; the fact that power flows, and therefore voltage ramps can be in either direction along a radial feeder means that using the local voltage to control on-load-tap-changing may no longer be feasible.

The addition of communications infrastructure which comes with an ANM scheme allows the control of transformers and voltage regulators in response to remote voltage or generator outputs. Such a scheme is known as co-ordinated voltage control.

In [2.19] a scheme is investigated which controls the on-load-tap-changing transformers using a remote voltage measurement. The scheme, known as area based co-ordinated voltage control, is combined with generation curtailment in an ANM scheme aiming to increase the level of distributed wind generation. The work shows that area based control can significantly decrease the curtailment required for non-firm generation. For example a 3MW wind farm would suffer 2500MWh of curtailment without voltage control, but this reduces to just 90MWh with area based control from a remote on-load-tap-changing transformer.

2.2.3 Reactive power dispatch of distributed generation

Distributed generation is usually treated only as a real power resource, so its reactive power capabilities are often ignored. In the early stages of development the design of wind turbines was based on induction generators, which operated at or near fixed power factors and had no control over reactive power. Induction generator based wind turbines operate at fixed rotational speed and therefore are not optimal at transforming wind energy into electricity. Developments over the past decade have led to most modern wind turbines operating as variable speed machines using either a Doubly -Fed Induction Generator or through back-to-back AC-DC-AC convertors [2.21]. Both technologies lead to a decoupling of the turbine (and its speed) from the grid: in the case of a doubly-fed induction machine the decoupling is partial; in the case of fully-rated convertors the decoupling is total [2.20]. By 2004, 73% of wind turbines were of variable, doubly -fed or fully rated convertor machines [2.21]. Figure 6 shows the three wind turbine design types.

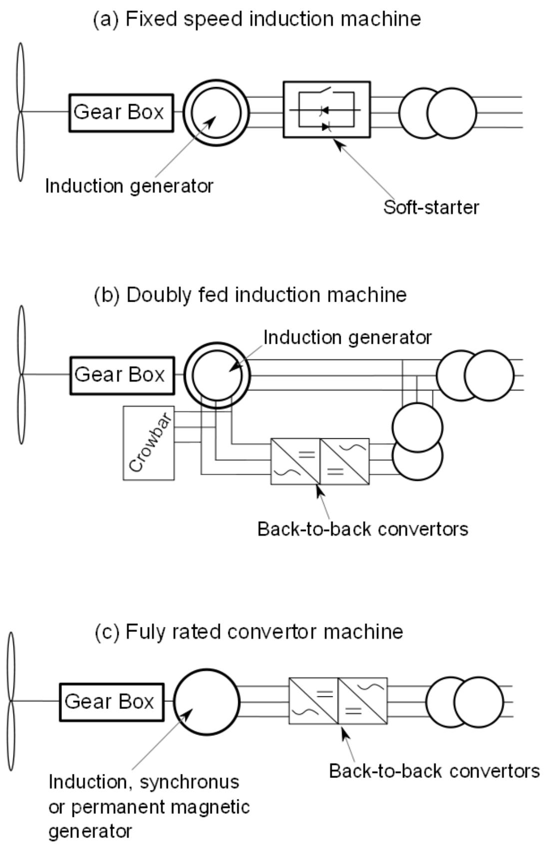

Figure 6: Summary of key wind turbine generator types. (Adapted from [2.22])

The inclusion of power electronic converters in doubly-fed induction or fully-rated machines allows for the dispatch of reactive power. A fully-rated convertor based machine can technically be able to provide full 4-quadent power control operating up to its rated apparent power at any power factor through the power electronic interface [2.23] and a doubly fed induction machine can provide between reactive power between 0.5 and 1 per unit depending on the real power output [2.21].

These developments in the design of wind turbines mean that modern wind turbines have the ability to work with the existing voltage control technologies on a distribution network to optimise the voltage profile to meet a particular objective.

Using reactive power dispatch, or power-factor control of wind turbines in an active network management context has been presented in a number of studies, see for example in [2.25-2.27]. Allowing centralised, or co-ordinated dispatch of reactive power from distributed generation, combined with centralised control of on-load tap-changing transformers and other reactive power devices can provide a powerful method of increasing the ability of a network to deal with voltages.

In [2.28] power factor control of distributed wind generation is studied in terms of its ability to increase the viable distributed wind capacity that can connect to a particular distribution network. The study is a multi-period optimal power flow study (see Chapter 3) which combines power-factor control of distributed wind generation, co-ordinated control of on-load tap-changing transformers and generation curtailment. If generation curtailment is not allowed, the combination of co-ordinated control of transformers and power factor control of distributed generation raises the viable capacity from 29.6MW (at the best fixed power factor) to 39.4MW, an increase of 33%.

2.2.4 Energy storage

Electricity is the ultimate perishable good. In most power systems its production and consumption must be matched near-perfectly on a second-by-second basis. This means balancing the conversion of the primary energy resource to the final energy demand across the network. Operating such a system securely leads to many additional costs beyond those associated with direct electricity generation: the cost of providing spinning reserve and ancillary services which hedge against faults and outages is a significant percentage of the total operating cost.

Further costs, either in monetary or emissions terms, arise from the fact that electricity from cheap generation cannot normally be transferred to other times. This is particularly apparent with variable output renewables such as wind power with very low marginal cost of generation but little correlation with demand.

Energy storage is able to reduce some of these costs by providing a method for storing energy from the electricity system and returning it later. Until recently the only technology capable of large-scale energy storage has been pumped-hydro. Today there are a range of developing technologies able to bulk time-shift energy with capacities of multiple MW and MWh. These include compressed air stores and battery technology (sodium sulphur, lead acid, lithium ion, nickel cadmium and flow-batteries) [2.29-2.32].

The first grid scale battery energy storage device connected to an ANM scheme was energised in mid-2013 on Orkney [2.33]. Over the coming year a battery is likely to be deployed in the ANM scheme being developed on the Shetland Islands [2.34].

2.2.5 Dynamic pricing and flexible demand

The concept of real-time pricing of electricity has been part of the wholesale electricity market since liberalised-electricity markets were introduced. However, small consumers have been excluded from this and are generally presented with fixed price or two-tier tariffs from electricity suppliers. This contributes to the almost complete inelasticity of demand for electricity seen in many power markets [2.35].

The introduction of dynamic pricing to distribution level customers has the potential to allow consumers to respond either manually or through automated smart meter control systems to price signals in close to real-time.

Variable pricing provides one example of flexible demand. Others include full centralised control of demand, centrally initiated interruptible demand, and other forms of hierarchical and distributed control. An overview is provided in [2.36].

Demand management is an example of an existing technological idea that is starting to be integrated into the ANM philosophy. A centralised demand management scheme is being deployed in the Shetland ANM scheme [2.34]. This scheme uses a central controller to send day ahead schedules out to storage heaters and electric hot water heating across the distribution network. The schedules can be varied each day to make greatest use of available wind generation. An interruptible load management trial has been applied to non-domestic demand for electricity in [2.37].

2.2.6 The wider energy system

The electrical network forms only a part of the energy system, other components include heat provision, transport and the gas network. The overall aim of energy policy is to balance the competing objectives of the *energy trilema* (see Chapter 1) across all aspects of energy. For example the EU 2020 targets for renewable generation is set as a percentage of total *energy demand* rather than total electrical demand [2.38]. The linkages between the electrical network and demand for heat and transport are likely to increase in the decades to come. This is partly due to the maturity of renewable electrical generation as opposed to other energy sectors: between 2004 and 2014 UK installed wind capacity rose from 809MW to over 10,00MW. [2.39, 2.40].

The link between electricity and heat systems is already apparent in areas with limited gas supply. In these areas, electrical heating is used in a significant fraction of houses – for example 28% in the Highlands of Scotland [2.41]. Storage heaters provide some level of flexible demand for electricity through the ability to store heat energy. As the technology is simply a resistive element, electric boilers are effectively 100% efficient at converting electricity to heat. Despite this, a significant improvement in the use of electricity can be achieved by using heat pumps.

As heat pumps use electricity to 'pump' heat from cool to warm areas they can output significantly higher quantities of useful heat than the quantity of electrical energy used. The ratio of useful heat energy out to electrical energy used is known as the coefficient of performance, and heat pumps can in some instances achieve coefficient of performance well in excess of unity [2.42]. In recent years heat-pump technologies have been used, notably in Scandinavian countries. Studies of the Danish power system have highlighted electric boilers and heat storage as low cost solutions in terms of managing fluctuating renewable energy sources [2.43]. Heat pumps are highlighted as the most effective method of reducing fuel used in a closed system.

However, electric boilers are 5 times cheaper than heat pumps per MW of heat output and provide an effective low cost option.

Another study of the Scandinavian power network [2.44] looked at the effect of heat pumps and electric boilers on wind-curtailment, power regulating costs and periods of low energy price. The results show that heat pumps produce significantly higher system benefits compared with electric boilers for the same installed heat output. However, the significantly lower cost associated with boilers lead to a higher ratio of benefits to costs.

A further way to integrate electricity and heat is through district heating networks. Whilst relatively rare in the UK, some countries have a high penetration of these. In Denmark for example, 46% of heat demand is met via district heating [2.45] often in conjunction with combined heat and power. Despite this already high baseline, studies have suggested that further expansion of district heating is one viable path towards a 100% renewable energy system [2.45, 2.46]. In a study of Ireland, a country with growing renewable energy production and very little district heating, the suggested scenario includes district heating networks providing heat to 55% of individuals [2.47]. Storage of heat is a simple technology when compared with storage of electricity, and management of the heat storage is important to ensure that wider energy-system goals are achieved. For example, under minimization of system costs, heat storage may lead to an increase in overall CO_2 emissions as cheap coal generation is substituted for expensive gas generation [2.48].

District heating is by its nature local, and can be directly connected to electrical distribution networks either via electric boilers, heat pumps or distributed combined heat and power plants. In the UK district heating is available in a number of locations including Lerwick on Shetland [2.49] and Sheffield city centre [2.50]. There has been interest recently in further developing district heating in the UK - the UK Government commissioned a report into the potential and costs of district heating [2.51]. This concludes that if district heating penetration is high it provides greater carbon savings compared to standalone renewable heat systems. The report does not include a comparison of wind-to-heat either as a standalone system or as part of a district heating network.

District heating networks provide an opportunity to efficiently link the electrical systems with the heat demand. There has been little work looking at the potential of combining a district heating network with an ANM scheme. One study, presented in [2.52] looks at linking a district heating scheme to an islanded distribution network through an electric boiler. The electric boiler provides a secondary heat supply to the district heating network from a waste incinerator. The study concludes that the availability of the electric boiler is beneficial to the electrical network in a number of ways: it can both manage periods of low electrical demand (a scenario noted as particularly problematic for an islanded distribution network) and increases the viable wind capacity that can connect to that network.

2.2.7 Other considerations for Active Network Management

As well as the technologies discussed above, there are a number of important design issues that ANM schemes must conform to. These are discussed here.

2.2.7.1 Fault Ride-Through

An important aspect of a grid with high penetrations of wind generation is to consider the response of those turbines during fault conditions. Grid codes have, over the past decade, enforced more stringent ride-through capability onto wind turbines. A detailed review of international grid code requirements for wind turbines is given in [2.53].

A key aspect of fault ride-through is the ability to ride-through voltage variations. Modern turbines are able to ride-through significant low voltage faults, including periods of zero voltage; examples include the Siemens full-convertor turbines [2.54] and Enercon [2.55]. In the UK today, distributed generation must meet requirements set by the distribution code and by Engineering Recommendations such as the G59 recommendations [2.56].

2.2.7.2 Fail-safe design

The design of ANM schemes must take into account how to respond to various failures within its systems. It is important that the failure of measurement devices, the communications system, control system or any other part of the ANM scheme does not lead to an insecure or dangerous situation developing. An example is the response of non-firm generation during a communication failure. As one role of ANM is to manage non-firm generation capacity, a failure of communications can be seen as a failure of ANM to perform this role. One way to ensure fail-safe design during the loss of communications is to ensure that the distributed intelligence at the non-firm generators is programmed to fully curtail the generator whilst communications are lost. In the case of ANM-controlled demand devices, the distribution network operator will have a requirement to maintain their supply of electricity despite a loss of ANM communications. In this situation it is important that a local mechanism is in place to ensure that consumers continue to have their requirements for electricity met.

2.3 A summary of Active Network Management schemes

All of the technologies discussed in Section 2.2 have been implemented on power networks. The role of ANM is to integrate the technologies with a recognisable and well-defined objective and co-ordinate their operation towards that goal.

In the UK a register of ANM schemes was compiled in 2008 which included pilots, trials and development / demonstration projects [2.57]. Analysis of the register, carried out in [2.58] suggests that the technical focus of projects at that time was towards communications and control systems, voltage control and power flow management. The majority of projects were at the research and development stage, with only 15% at full deployment stage.

Since 2010, the UK energy regulator Ofgem has provided funding for a number of distribution network projects via its Low Carbon Network Fund stream worth £500 million [2.59]. So far across the UK, 15 large-scale projects have been funded on distribution networks [2.60] and a range of smaller projects.

Beyond the UK, a number of electricity networks are trialling and deploying ANM-type solutions. For example, the Danish island of Bornholm [2.61, 2.62] is being used as a demonstration of a smart distribution network containing a high penetration of renewables and including energy storage and flexible demand. The Olympic peninsula in Washington State, USA [2.1], is a test bed for dynamic pricing and price responsive load.

This section presents a review of some ANM schemes currently in operation and planning.

2.3.1 Orkney Active Network Management scheme

Generation on the Orkney distribution network, shown in Figure 7, is managed by an ANM scheme and is one of the first fully deployed smart grids in the world. The concept of an active network management scheme was developed through a project funded by the Department of Trade and Industry in 2004 [2.63]. This project looked at the potential of increasing the penetration of renewable generation connected to the Orkney network beyond the firm limit of 26MW, which had been filled by 2004. It identified two tranches of additional generation which it defined as Non-Firm and New-Non-Firm generation. Together with firm generation these terms are defined as follows[2]:

[2] The terminology used for generation on Orkney differs from the terminology used elsewhere in this thesis. The definition of *non-firm generation* used in this thesis is equivalent to the definition of *Orkney new-non-firm generation*. *Orkney non-firm generation* forms part of the *firm generation* as defined in this thesis. The prefix 'Orkney' is added to the terms when using the nomenclature of the Orkney project to aid understanding.

- **Orkney Firm Generation:** This has guaranteed network access. Orkney is connected to the national grid via two undersea cables. The capacity of firm generation is set by the capacity of the smallest of these and the minimum demand on Orkney. This ensures that the loss of either cable on its own will not disrupt the operation of firm generation.
- **Orkney Non-Firm generation:** An additional 21MW of generation, which brings the total up to the combined capacity of both undersea cables plus minimum demand limit. Non-firm generation is tripped in the case of the outage of one of the undersea cables, and does not need to be compensated for the loss of network access during an outage.
- **Orkney New-Non-Firm Generation:** This generation will be subject to curtailment during normal (i.e. non-fault) operating conditions so as to maintain the power flow along the undersea cables within their limits. Other constraints may force the curtailment of generation: voltage limits (due to the voltage rise effect); and power-flow congestion at other parts of the network. Currently thermal limits are binding on Orkney.

The initial report noted that a total of 72MW of generation could be connected (26MW of Orkney firm, 21MW of Orkney non-firm and 25MW of Orkney new-non-firm generation); of the 25MW of Orkney new-non-firm it was expected that 15MW would be economically feasible. As of January 2013 the Orkney new-non-firm capacity that had connected was 18.46MW [2.13].

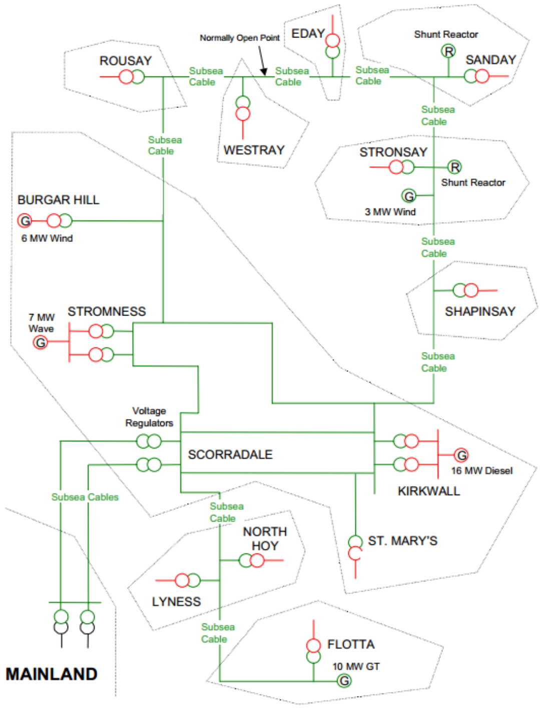

Figure 7: Outline of the Orkney Islands Distribution network (taken from [2.64])

The key components of the Orkney ANM control and communications systems are shown in Figure 8. The diagram shows the required redundancy in the systems, for example the requirement for two control hubs (SGCore) and two communications servers (CommsHub).

A key design feature of the Orkney ANM scheme has been its ability to fail to a safe state. This is true for the system as a whole and for particular elements. A key learning outcome of the project to date has been the importance of communication systems. It was noted that the reliability of the private-wire telecommunications links used by the generators was not as high as expected, with one link's availability dropping to 96.3% [2.64]. This has led to additional curtailment for generators as the fail-safe behaviour of the local controller is to fully curtail all generators when communications are lost [2.15].

Future developments planned for the Orkney ANM scheme include an energy storage park, dynamic line ratings and demand side management [2.65], and these are expected to be rolled out over the coming years.

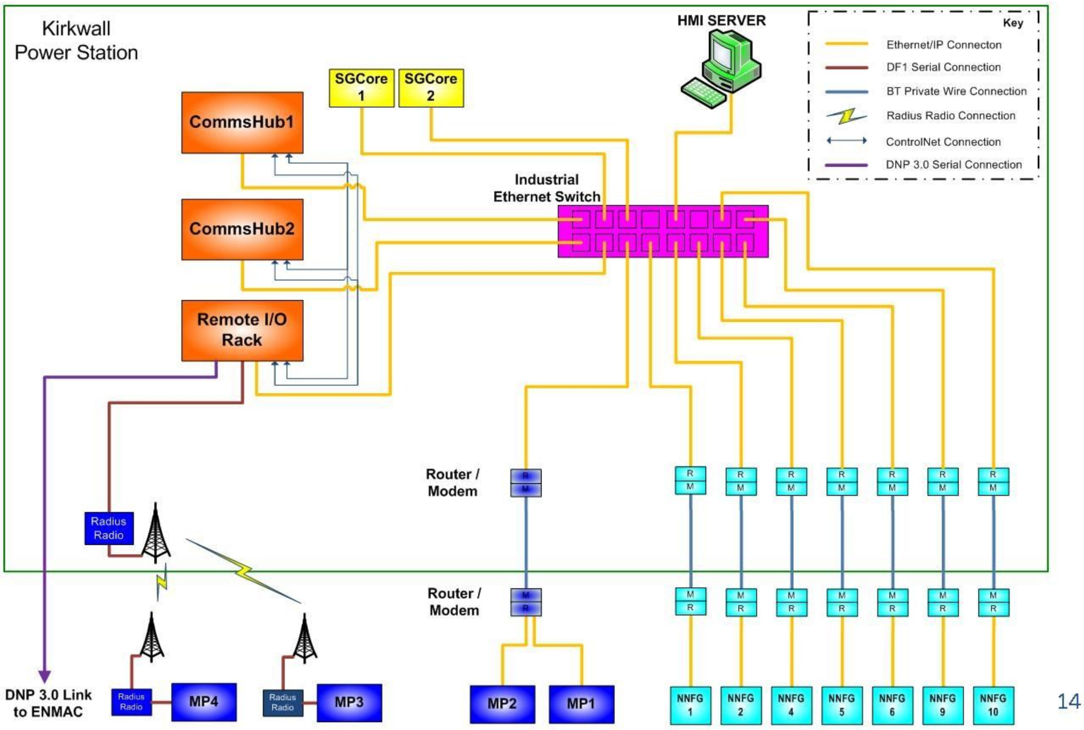

Figure 8: Communication and control infrastructure for the Orkney ANM scheme. SGCore is the commercial control packaged, communications are installed between measurement points (MP) Orkney new-non-firm generation (NNFG) and a Human Machine Interface (HMI) allows interaction with the system from the control room (taken from [2.64]).

2.3.2 *Shetland Active Network Management scheme*

The Shetland Islands lie approximately 100 miles north of the UK mainland and are home to a population of 22,000. Shetland is electrically islanded and has an incredibly good wind resource. Currently the 3.6MW Burradale Wind Farm is the only significant wind generation connected to the grid and has in the past achieved a capacity factor across a year in excess of 0.5 [2.66]. There are two other generation stations on Shetland: gas turbines at Sullom Voe Terminal and diesel engines at Lerwick Power Station. Figure 9 shows Shetland's network and geographical location.

As with other networks, distributed wind generation capacity on Shetland is limited by the worst case scenario, but unlike transmission connected distribution networks the limiting factor is not currently voltage and thermal limits but network stability. The islanded network has limited inertia and there is the possibility that wind fluctuations, or the simultaneous tripping of protection on all distributed wind generation could, under some circumstances, take the network outside its statutory frequency limits.

Whilst the constraints on Shetland have different technical causes compared with other distribution networks, the ability to use generation curtailment to increase capacity for wind generation can be achieved in a similar way. Network studies can identify maximum stable wind levels under various operating scenarios, and these limits can be maintained through real-time monitoring and control.

The ANM scheme on Shetland is part of the Northern Isles New Energy Solutions (NINES) project [2.34, 2.67], the aim of which is to raise the capacity of renewable generation that can connect to the islanded network and make the maximum use of the available renewable generation. This project involves an ANM scheme which will control not just wind generation but energy storage and flexible demand. The addition of these two components provides an additional layer of complexity to the control systems and central intelligence required. It is also expected that several of the ANM controlled devices – flexible demand and potentially the energy storage – will operate in a frequency-responsive mode. The components that are expected to form part of the ANM scheme are shown in Table 1.

A key objective of the NINES project is to define stable operating conditions in terms of the maximum instantaneous generation from wind for all expected operating conditions. This will depend on a number of factors including which conventional

(a) (b)

Map Data © 2013 Google

Figure 9: The Shetland Islands. (a) the islanded distribution network, and (b) the geographical location.

plant is on line, the current system demand, and the availability of frequency-response from the frequency-responsive demand devices.

The NINES project marks a significant increase in complexity for ANM schemes. Energy storage and flexible demand are both intertemporal technologies and they cannot be used to their optimal capacity simply by controlling in real-time. The addition of these devices is leading to the requirement to use forecast information and advanced scheduling algorithms within ANM schemes.

The Shetland ANM project forms the basis of the case study presented in Chapter 7 of this thesis. The research presented in this thesis has been deployed to assist in the design and deployment of ANM on Shetland.

Table 1: Devices potentially under ANM control in the NINES network

Component	Description	Expected Capacities
Non-Firm Wind	New wind generation under the control of the ANM scheme	10 – 15 MW
Energy Storage	A chemical battery	Initially 1MW, 0.5MWh Later 1MW, 3MWh
Central Controller	Tasked with scheduling energy storage and flexible demand on a day-ahead basis, monitoring NINES components in real-time and controlling non-firm wind in real-time	
Domestic Demand Side Managed Demand (DDSM)	Modern, efficient electric storage heaters and electric water heaters. Storage of heat allows flexibility in the timing of delivery of electrical energy. These components have the ability to provide frequency-response.	Initially 250 homes connected 2013 – 2014.
Large-scale industrial electric boiler	An electric boiler linking the electrical network to a district heating network via a large heat store. The electric boiler will take power only from wind generation. This component has the ability to provide frequency-response.	4MW with a 150MWh heat store.

2.3.3 Customer Led Network Revolution project

The Low Carbon Network Funded project *Customer Led Network Revolution* [2.68] links a number of technologies in a single smart grid. It involves a number of existing and developing ANM technologies at the distribution network level. The technologies include demand side management through consumer participation, real-time thermal ratings, distributed generation, electric vehicles and energy storage.

The project is concerned with developing flexibility in terms of consumers and the network and studying what the optimal solution should be. For consumers, a range of flexible demand tariffs are being trialled, including time-of-use, restricted hours and direct control.

The use of energy storage is being trialled at both the medium and low voltage distribution levels. In [2.69] the use of energy storage as one tool for voltage management is discussed. Energy storage is combined with flexible demand to give a method of maintaining voltage within static limits in the face of high penetration of distributed renewable generation.

The project highlights the integration of multiple technologies as an important challenge for distribution networks. The Orkney ANM scheme has demonstrated the effectiveness of monitoring and control of a single technology: generation curtailment. The Customer Led Network Revolution project is extending that concept to multiple technologies and extending the range of operation down to the low voltage (400V) network.

2.3.4 Other UK distribution network projects

Many Low Carbon Network Funded projects are providing a range of successful experiences on which UK distribution network operators can draw when designing future ANM schemes [2.70].

Other relevant projects in the UK include the following:

- The use of ANM to provided coordinated voltage control on an 11kV radial distribution feeder in north Wales that includes a hydro-generator with a non-firm contract. The concept will use voltage measurements at a number of locations on the feeder to calculate if additional non-firm generation capacity can be accepted in real-time, and control the release and subsequent trimming and tripping of that generation [2.71].
- The *Flexible Plug and Play* project in eastern England is looking to extend the concept of principles of access (See Section 2.2.1). Currently *last-in-first-out* is the only principle that has been applied to a real distribution network. The project aims to implement a shared percentage arrangement where each generator is curtailed as a proportion of its output. This will share the

curtailment equally amongst non-firm generators. The project has identified a meaningful limit on the capacity of wind generation that will be allowed to connect under the non-firm *pro rata* arrangement. This project again highlights the *benefit* of wind generation: carrying out an expensive network upgrade to relieve a small amount of curtailment is not a *valuable* investment however carrying out the upgrade to benefit a larger capacity may be a valuable investment if the costs of curtailment and upgrade are compared [2.72].

The projects described in Sections 2.3.1 to 2.3.4 highlight a definite focus on centralised and co-ordinated control structures as a feature of UK ANM projects. The projects distribute some level of intelligence, however this tends to be related to measurements and in the ability to respond in pre-defined ways to central control signals.

In contrast, a more distributed control philosophy can be achieved through the response of individual market participants to a price signal. The concept is similar to that which is applied to pool-based electricity markets at transmission level [2.35], and a number of international projects highlight the possibilities of using such a method at the distribution level.

2.3.5 International smart distribution networks

Two international projects are highlighted here to illustrate the possibilities of distributed control in the context of actively managed distribution networks. The first is in Europe and the second in the USA. Whilst there are many such projects these two relatively large projects highlight the potential role of distributed market-based mechanisms in smart distribution networks.

2.3.5.1 EcoGrid EU – A smart grid on the Island of Bornholm

The EcoGrid EU project [2.61, 2.62] based on the Danish island of Bornholm is taking a significantly different track to the UK ANM systems described above and provides a useful comparison with the direct control philosophy being adopted in the UK.

The objective of the project is 'to illustrate that modern information and communication technology… and innovative market solutions can enable the operation of a distribution power system with more than 50% renewable energy sources' [2.73]. The key difference between this and UK ANM is the incorporation of market mechanisms; this is the focus of the project.

The Bornholm smart grid market is based on a bid-less market system in which individuals decide in advance to respond to particular price levels and simply respond to the centrally controlled price a price set by an independent market operator with settlement periods of 5 minutes. Distributed resources, both generators and demand, can respond to the price signals by choosing to generate/consume at the current price. The concept allows market participants to engage with a regulating power market as well as a real-time power market. Finally, there is the ability to provide locationally-dependent price signals to manage distribution network congestion. The roll-out of the project is proposed in three stages: the provision of balancing services by distributed energy resources; stage two involves the addition of grid management technology and automation; and the final stage involves the introduction of the locational pricing aspect of the system.

The market concepts in the Bornholm smart grids partially map across to the central-control concepts of the UK ANM schemes described.

- **Real-time market:** the bidding of market participants assumes that they have made predictions about their likely generation/demand over the near future. Market mechanisms allow the market participants to make judgements on likely accuracy of forecasts, risk etc. In the Shetland ANM scheme, it is the role of the central ANM controller to receive and interpret forecasts before directing generators and other devices rather than leaving this to customers themselves. This highlights the current trend among UK networks to avoid market based mechanisms and rely on more deterministic methods.

- **Reserve markets:** In ANM schemes operational rules are defined through knowledge of the flexibility of various network components. Specific requirements are placed on particular participants, such as the ability to ramp at particular rates and respond to control signals in a particular time-span. The market mechanism provides a price-based incentive for market participants to do the same thing. Again, this removes the requirement for centralised control under the assumption that the market is able to provide the required flexibility at all times.
- **Locational pricing:** the objective is to use this on the Bornholm smart grid to manage network congestion. In ANM this role is carried out by the thermal and voltage limit rules and operating margins. As noted before, ANM relies on a centralised analysis of the network, whereas a market mechanism attempts to distribute the control to individual participants based on a price signal.

2.3.5.2 *Olympic Peninsula – Dynamic Pricing*

The concept of managing an electrical network through a price signal has been demonstrated on the Olympic peninsula, Washington State, USA. The area is part of the Bonneville Power Administration grid. The project, implemented by Pacific Northwest National Laboratory, introduced price-responsive control to a range of demands on a local distribution network, with the aim of managing congestion on a feeder, lowering peak demand and demonstrating the viability of implementing market mechanisms directly to small-scale customers [2.1]. As with other smart grid projects, the objectives include the important outcome of deferring investment in network upgrades.

The project creates a market for demand and some distributed generation with a 5-minute settlement period. Unlike the Bornholm model, participants must bid into the market for each settlement period and the market operator then balances the market.

The project forms one of the test beds for Pacific Northwest National Laboratories' GridWise concept. In [2.1] Grid Wise is described as a term 'coined at PNNL [Pacific Northwest National Laboratories] to describe the various smart grid management technologies based on real-time, electronic communication and intelligent devices' ([2.1], page v). As such it is a similar concept to ANM. Unlike ANM, a key aspect of GridWise implementations are expected to be the use of 'real-time' communications of market-like incentives' ([2.1], page 1.2).

Conclusions from the trial show that the dynamic pricing scheme was successful at managing congestion on the feeder and at lowering peak demand. When there was no congestion, the local price was almost the same as the wholesale price – that is the feeder itself effectively set the clearing price within the trial. When the feeder was congested, the price rose high enough to encourage enough load to defer its operation to a later time so that the congestion was removed. With high prices, additional distributed generation was encouraged to operate and therefore increase the load that could operate.

Unlike the UK examples discussed, the Olympic Peninsula project manages excessive demand (rather than excessive generation), although the same method can be applied to wind generation and curtailment. As with the Bornholm grid, the project distributes control to specific users and employs a market mechanism to ensure that constraints are maintained. The need for a market-clearing mechanism increases the need for centralised intelligence compared with Bornholm, but there is still more autonomy given to distributed intelligence compared with ANM.

2.3.5.3 Smart Grid – the international direction

These two smart grid projects illustrate the general direction internationally towards market based mechanisms. This differs from the strategy currently shown by the more centralised and deterministic control mechanisms introduced via ANM schemes to date.

The likelihood is that the ANM model will, over the coming decade, integrate some of the lessons currently being learned in market-based smart grid projects. The advantage of the centralised control model is that the distribution network operator is certain of retaining authority, with the ability to control network components. It allows simple deterministic rules to be followed which allow for participants in an ANM scheme to easily understand the system, and in the case of LIFO, curtailment has proven to be acceptable to banks.

However, development such as the Orkney Energy Park [2.65] show that the UK is beginning to consider market-based mechanisms to trickle down to distribution level. The role of market-based mechanisms for responsive demand must be seriously considered, as it allows consumers to maintain control of their demand, rather than ceding it to the network operator - as is happening in the Shetland NINES project [2.34].

Tools to analyse and provide efficient market mechanisms to the distribution network will be similar to those developed at transmission level. The ability to efficiently define prices signals that vary with time and location already exist in the form locational marginal pricing markets. Chapter 6 of this thesis extends these ideas to the results of Dynamic Optimal Power Flow (DOPF) and include energy storage and flexible demand. Such tools will be important for analysing the types of market suggested by Olympic Peninsular and Bornholm.

2.4 Research challenges for Active Network Management

In 2004 the main research challenges for active management of distribution networks were identified as: facilitating the economic analysis of generator connections; demonstrating the potential for increased renewable generation; and establishing the steps involved in the transition from passive to active management [2.74].

Nearly a decade later these three challenges still stand but in the new context of second-generation ANM. First generation ANM has been developed and successfully deployed and is becoming business-as-usual for distribution network operators as shown by the inclusion of ANM in business plans for all distribution network operators for the price control period 2015-22 [2.75]. Increases in renewable capacity have been achieved, and the economic viability of ANM has been shown in practice.

The new context for these three challenge as of 2013 can be summarised as:

- **Facilitate economic analysis of generator connections:** simple commercial arrangements in the form of LIFO have been implemented for ANM schemes. These are simple and transparent but less than optimal in terms of maximising the capacity of distributed wind generation. Principles-of-access will become more complicated in the interactions with energy storage and demand flexibility. A key challenge for research is to develop tools and perform analysis on a range of commercial arrangements for distributed generation to both the network and to intertemporal technologies such as energy storage, flexible demand and other technologies. This last challenge is highlighted by the results of optimisation studies in Chapter 5 of this thesis.
- **Demonstrate the potential for increased renewable generation:** research needs to develop tools which show how existing and developing ANM schemes which make use of generation curtailment can best utilise flexible technologies such as energy storage and flexible demand. They also need to characterise the *benefit* of renewable generation and how this varies over time.
- **Establish the steps involved in the transition from passive to active management:** a number of steps have not only been established but have been enacted leading to the current model of ANM becoming business as usual for distribution network operators. The introduction of intertemporal technologies is the next key stage and the next steps that research needs to develop are likely to involve forecasting, scheduling, and the integration of market mechanisms – the move from first to second-generation ANM schemes.

In Box 1, (section 2.1) a working definition of ANM based on the existing literature is given. This definition holds true for existing schemes, however intertemporal technologies requires an updated *second-generation ANM definition.* This chapter has discussed that this will extend the real-time monitoring and control philosophy to one that includes scheduling in advance of operation. Box 2 gives an updated working definition of second-generation ANM.

> Second-generation Active Network Management means the extension of ANM to include intertemporal technologies and the use of advanced scheduling of network components in response to real-time measurements and forecasts of future conditions.
>
> **Box 2:** A working definition of second-generation Active Network Management.

This extension is made concrete in the contributions the author has made to the schematic representation of the ANM scheme being developed on Shetland and to be detailed in subsequent chapters. In addition to the move to second-generation ANM there is evidence that future schemes will further distribute control.

Technologies expected to be included in ANM over the coming decade already exist as noted in [2.76], the challenge for ANM is to coordinate their operation to help achieve the overarching goals of power system operation. This thesis develops optimisation tools including DOPF to achieve these.

2.5 Conclusions

This chapter has reviewed the development of ANM to date in the UK in terms of technologies and projects. It has highlighted the strategy of ANM as one of moving towards real-time monitoring and control with a strong emphasis on centralised, coordinated control of distributed action. It has highlighted that the second-generation of ANM schemes will include both forward scheduling and the use of forecast information as the integration of greater capacities of distributed wind generation continues to drive the development of ANM schemes.

The ANM philosophy is contrasted with the move towards more distributed control via market-based mechanisms, which is happening outside of the UK. It is noted that market-based mechanisms are likely to become more acceptable in UK distribution networks over the coming decade.

The review shows that ANM is a successful mechanism for directly encouraging greater capacity of distributed wind generation, through the development of non-firm contracts for generation curtailment schemes. Intertemporal technologies such as energy storage and flexible demand are highlighted as being of importance to ensure greater use of installed non-firm generation capacity and also to reduce curtailments.

Finally, to achieve greater integration of wind generation in ANM schemes, the need for new analysis tools is highlighted, particularly ones that consider the overarching objectives of ANM schemes.

This thesis tackles these challenges by developing tools to analyse second-generation ANM schemes and assist with the scheduling of intertemporal technologies. The effect of intertemporal technologies can be studied in general using simplified models of distribution networks, and this is the approach taken in Chapter 4. However, it is important that the intertemporal and network effects are combined. The joining together of the two effects in a DOPF is the topic of Chapter 5. The potential role of varying prices by time and location as suggested by the international direction of travel towards market-based mechanisms is developed in Chapter 6 with the concept of Dynamic Locational Marginal Pricing. Finally, the tools developed are applied to the development of a real second-generation ANM scheme in Shetland and this is detailed in Chapter 7.

The next chapter reviews the optimal power flow based tools applied to distribution networks energy storage and flexible demand.

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Chapter 3: Optimising distribution networks using Optimal Power Flow

A POWER SYSTEM SHOULD be operated in a way that ensures it can achieve the objectives set out for it. As discussed in Chapter 1, the objectives defined for most power systems are based around low carbon operation, cheap generation and security of supply. The new technologies and techniques of Active Network Management (ANM) discussed in Chapter 2 needs to be directed towards those objectives. Wind power will be instrumental in reducing carbon emissions but its value can be limited by the difficulties its integration imposes on the network. Smart distribution networks operating with an ANM philosophy must try to extract benefit from distributed wind generation whilst managing the difficulties.

This chapter reviews the literature of optimising distribution networks, concentrating on the role of Optimal Power Flow (OPF). At transmission level, OPF has traditionally been used to dispatch a pre-defined set of generators to minimise either overall costs or system losses. At distribution level, a range of innovative methods have been used to apply the method to the specific problem of distribution network planning and operation. At both levels OPF is a tool for analysing the operation of a network at a snap-shot in time. This chapter notes that such optimisation strategies are not suitable for the optimisation of intertemporal technologies and identifies Dynamic Optimal Power Flow (DOPF) – initially used in hydro-thermal generation planning – as a tool to be developed.

The chapter concludes that many existing ANM techniques are well modelled by existing OPF formulations, including most non intertemporal technologies. Existing methods can study basic wind curtailment and coordinated voltage control. However, it identifies the need for tools which can combine both network and intertemporal effects in a single framework. DOPF is highlighted as a tool which can provide this, and this is a key gap in the literature that this thesis fills.

3.1 A Description of Optimal Power Flow

Optimal power flow was first developed in the 1960s [3.1] as a non-linear mathematical programming problem for power systems. In this initial formulation it was used to minimise operation costs or minimise system losses. The scope of an OPF is to minimise an objective function whilst taking full account of network power flow equations, generator limits, line limits and voltage limits at all buses. It therefore produces a solution which can be implemented on the real power system whilst maintaining realistic operational limits and taking account of both real and reactive power flows and network losses. A number of references provide an introduction to the concepts of OPF [3.2-3.4].

Mathematically an OPF problem can expressed as a general optimisation:

$$\min\{f(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{z})\} \tag{3.1}$$

Subject to:

$$\boldsymbol{g}(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{z}) = \boldsymbol{0} \tag{3.2}$$

$$\boldsymbol{h}(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{z}) \leq \boldsymbol{0} \tag{3.3}$$

Where f is the objective and is a function of control, fixed and derived variables $(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{z})$ respectively; see below for definitions); $\boldsymbol{g}(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{z})$ is the set of equality constraints and $\boldsymbol{h}(\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{z})$ is the set of inequality constraints.

Control variables ($\boldsymbol{x}$) for an OPF problem are those which can be adjusted, within certain ranges, whilst maintaining a *viable* solution to the power flow problem. The aim of the OPF process is to find the values of the control variables, $\boldsymbol{x} = \boldsymbol{x}^*$ which represents the optimal solution.

Fixed parameters ($\boldsymbol{y}$) include power injections at buses without controllable generation, for example buses with load only. For the purpose of a particular optimisation they are therefore constants and can be removed from equations 3.1 – 3.3.

Derived variables are the remaining unknown variables which are functions of control variables and fixed parameters. These variables include bus voltage magnitudes at all buses and voltage angles at all buses excepting one (designated as the reference bus).

Specifying the set of equality constraints for OPF problems requires forming the power flow equations. The power flow problem is based on two fundamental laws of physics: ohms law; and conservation of energy. The power flow problem can be formulated as:

$$V_k \sum_{n=1}^{N_B} Y_{kn} V_n cos\,(\delta_{kn} - \theta_{kn}) - P_{g,n} + P_{d,n} = 0 \tag{3.4}$$

for real power, and:

$$V_k \sum_{n=1}^{N_B} Y_{kn} V_n sin\,(\delta_{kn} - \theta_{kn}) - Q_{g,n} + Q_{d,n} = 0 \tag{3.5}$$

for reactive power. In these equations: V_k is the voltage magnitude at bus *k;* δ_{kn} is the difference in voltage angles between bus k and each bus *n;* $Y_{kn}$and θ_{kn} are the magnitude and argument respectively of the admittance between bus k and each bus *n;* $P_{g,n}$ and $P_{d,n}$ are the generated and demanded real power at bus *n;* and $Q_{g,n}$ and $Q_{d,n}$are the generated and demanded reactive power at bus *n.*

This set of *2N_b* equations form the equality constraints of the OPF problem and are in the form of energy balance equations: the energy flow as determined by the power flow equations are the first term, whilst the defined power generations and demand form the second and third terms respectively.

The inequality constraints defined by equation (3.3) in general represent the physical realities of the power system in question. They include minimum and maximum generation limits, line flow limits and voltage limits:

The solution of this optimisation can in many useful circumstances be found using non-linear programming techniques [3.5]. For this to be the case, the objective function and constraint functions must be smooth; that is continuous and differentiable at least twice. In addition they must also be convex to allow the application of the Kuhn-Tucker Theorem [3.6]. If these conditions are met, the local direction and magnitude of the function's gradient can be used to give information on the location of the global minimum of the function.

The Lagrangian function related to the OPF problem can be written as:

$$\mathcal{L}(\boldsymbol{x},\boldsymbol{z},\boldsymbol{\lambda},\boldsymbol{\mu}) = f(\boldsymbol{x},\boldsymbol{z}) + \boldsymbol{\lambda}^{\boldsymbol{T}}\, \boldsymbol{g}(\boldsymbol{x},\boldsymbol{z}) + \boldsymbol{\mu}^{\boldsymbol{T}} \boldsymbol{h}(\boldsymbol{x},\boldsymbol{z}) \tag{3.6}$$

where $\boldsymbol{\lambda}$ and $\boldsymbol{\mu}$ are vectors of multipliers associated with the equality and inequality constraints; and the vector of fixed parameters, $\boldsymbol{y}$, has been dropped. The Lagrangian multipliers, $\boldsymbol{\lambda}$ are a simple application of Lagrangian optimisation [3.0.1]. The multipliers $\boldsymbol{\mu}$ (sometimes known as the Kuhn-Tucker Multipliers) derive from the Kuhn-Tucker Theorem as presented in the appendix to [3.1].

The physical interpretation of the multipliers at the optimum are of interest in the solution. They represent the gradient of the objective function with respect to the constrained variables, or to put it more simply: they represent the marginal cost associated with that constraint. The vector $\boldsymbol{\lambda}$ therefore represents the *marginal cost* of increasing the supply of real and reactive power at each bus. The vector of $\boldsymbol{\mu}$ gives the shadow prices of the inequality constraints; that is the marginal cost or benefit associated with tightening or relaxing that constraint on the optimal value of the objective. If an inequality constraint is not binding, its associated μ is equal to 0 as the marginal effect of varying the limiting value is zero. A more detailed discussion of multipliers is given in Chapter 6.

3.2 Solution methodologies for Optimal Power Flow

The first methodology applied to solve OPF problems as a non-linear programming problem was Newton's method [3.1]. The problem is classed as non-linear due to the presents of a non-linear objective function or constrains functions. In OPF the power flow equations are sinusoidal, and the cost functions are often quadratic. A range of non-linear programming methods have been used, including gradient methods, Newton's method [3.1], interior point and decomposition methods such as the decomposition into separate real and reactive power problems [3.7].

The full AC OPF formulation is computationally expensive has historically been slow to solve. With modern computers this is unlikely to be a problem with standard OPF problems, however extensions of OPF such as the Dynamic Optimal Power Flow presented in chapter 6 of this thesis, computational time may become an issue. The use of the DC power flow equations or a fast decoupled power flow can produce a faster optimisation problem that are useful for application to transmission networks [3.8]. The use of DC OPF in transmission networks to solve real-time problems is common, but in distribution networks both the assumptions of equal voltage at all buses is unrealistic because of higher resistance/reactance ratios. As such full AC OPF is required for distribution networks.

During the 1980s a new mathematical programming technique called the Interior Point Method was developed, initially for linear programming problems [3.10] and later for non-linear programming problems. A discussion of the application of the Interior Point Method to non-linear problems is given in [3.11]. The method significantly outperforms other mathematical programming algorithms and are now used as the default solution methods in some power system analysis packages, for example Matpower [3.12]. Many of the modern applications of OPF use the interior point method due to its computational efficiency. The OPF carried out in this thesis makes use of interior point-based solvers.

As well as traditional mathematical programming techniques, the last decade has seen a wide range of heuristic optimisation techniques applied to OPF, for example: genetic algorithm [3.13]; particle swarm [3.14]; and tabu search [3.15]. In general, heuristic techniques have a number of advantages over mathematical programming [3.16]: they have no requirement that the functions are smooth, differentiable, convex or in some cases even analytic. Many heuristic methods can also carry out multi-objective analysis; true multi-objective analysis produces a pareto-front of optimality from which improvements in one objective are seen as traded off against deterioration in other objectives.

Whilst there are many advantages to heuristic optimisation, it has yet to find full acceptance within the power system industry. For example, a number of commercial packages such as PSS/E are accepted as industry standard by transmission and distribution system operators [3.17] and use classical optimisation techniques. In the near future it is therefore expected that new tools bases on classical optimisation are more likely to be acceptable to the industry. Heuristic methods can be computationally intensive to implement and are effectively directed random search processes which do not guarantee to find the true minimum, whereas in contrast classical techniques are deterministic and, assuming the conditions of convex continuous differential functions holds true, do guarantee to find the global minimum.

3.3 The application of Optimal Power Flow

The general formulation of optimal power flow has been applied to a wide range of objective functions. The initial formulation described OPF for minimising operating costs and minimising network losses [3.1] and a review of the literature from 1991 provides detail of the early applications of OPF methods [3.18].

The following general objectives and applications of standard OPF can be found in the literature.

Minimisation of fuel costs: presented in the original OPF formulation and representing a form of economic dispatch [3.3] that fully included network effects, the minimisation of fuel costs is the most studied early application of OPF [3.18]. It is similar to economic dispatch, with the addition of network effects and reactive power considerations.

In a deregulated electricity market such as that in the UK today, the cost curves of generators will not be known by the market operator. If the market is assumed to be efficient, the level of offers that a generator places to generate particular quantities of electricity should be the same as its marginal cost of production. In the case of an efficient market offer curves can replace cost curves directly.

Minimisation of losses: the minimisation of system losses can be achieved by forming an objective as the sum of all generator real power outputs. As total generation must equal total demand plus total losses, if total demand is fixed then minimising generation is equivalent to minimising losses [3.1].

Security-constrained OPF: solves a single optimisation problem for multiple topologies of a given power network. Each topology of the network includes a particular contingency event, for example the removal of a particular transmission line. Solving the security-constrained OPF provides an optimal solution that will remain viable after any of the incorporated contingency events [3.19].

Emissions based OPF: Including emissions in OPF can be achieved in two ways. Either emissions limits are enforced as additional constraints, or emissions can be formulated as part of the objective and minimised. The two methods are presented as part of economic dispatch and extended to an OPF formulation in [3.20]. In [3.21] the cost of NO_x emissions are minimised by combining an emissions function with fuel costs in the objective and placing limits on individual and overall emissions. The paper notes that minimising fuel costs and emissions are opposing objectives, and the method proposed approaches this by combining the two objectives using a weighting function.

This paper is interesting in that it extends the usual single-period OPF concept to cover an entire day by solving a larger problem consisting of the OPF problem at many time-steps throughout the day. There are no electrical linkages between the time-steps, each copy of the network is electrically islanded and therefore obeys the power flow equations independently. However there is an intertemporal constraint on total emissions output that limits the *total* emissions from each copy of the network.

The incorporation of CO_2 emissions into OPF is a more recent development. In [3.22] a cost model of CO_2 emissions is developed that models the output of CO_2 for different generation technologies with their power outputs and combines this with a unit price for CO_2.

Maximisation of social welfare: The standard costs minimisation OPF is a simplification of the more general *maximisation of social welfare model* that includes demand as well as generation flexibility. Most OPF formulations ignore demand flexibility, as the demand curve for electricity is assumed, at least in the short term, to be fully inelastic [3.23]. The ability for consumers to respond to price variations is a key driver of some aspects of *smart grid* and the incorporation of this into OPF is therefore an important consideration. Incorporating demand flexibility is investigated in [3.24] and [3.25], where the demand is modelled as decreasing with price. The concept is important for the market-based concepts of demand flexibility used in the Bornholm and Olympic Peninsula projects discussed in Chapter 2.

Maximise distance from voltage collapse: Avoiding voltage collapse is vital for any power system operator, as such the ability to schedule generation in a way which minimises its risk is useful. In [3.2] (page 138) an OPF with maximisation of distance from voltage collapse is described. It identifies the power flow conditions related to the maximum loading of the network as the critical point. A loading margin is defined and the method effectively maximises that loading margin.

3.3.1 Applying Optimal Power Flow to passive distribution networks

The application of OPF to distribution networks has had a different and more recent development to that of the general formulations discussed above. Until the advent of *smart grid* concepts such as ANM, distribution networks were operated almost entirely passively and had no scope for operational optimisation. Some control was provided by tap-changing transformers and other voltage control devices, but their operation was fixed in terms of maintaining a voltage within target ranges. In the context of passive distribution networks, OPF has been used to consider planning issues such as maximising capacities of distributed generation. The development of ANM and other *smart grid* concepts has allowed OPF to be used to consider operation as well.

Unlike transmission-based OPF the assumptions required to linearise the power flow equations are not applicable to distribution networks due to the high R/X ratio leading to greater losses and variable voltage levels.

This subsection reviews some of the applications of OPF to passive distribution networks and leads onto the application to active distribution networks in section 3.3.2.

The first applications of OPF to specific distribution network contexts was to study the problems of infrastructure investment. These problems included defining the best location of distributed generation or reactive compensation.

In 1994, a study [3.26] presented an OPF that minimises the power losses or some other measure of network performance by distributing a fixed-power injection optimally among a number of buses. The method works by optimising the power injection at a sub-set of all buses as control variables. The total power injection is constrained by an equality constraint ensuring that the total power injection is the same. The result is that the fixed total generation is optimally distributed across the available buses. The process presented considers a single load case and so can be used to estimate losses at the peak load, with DG producing at its capacity limit.

A similar technique is used in [3.27] to find the maximum headroom for distributed generation on a network consisting of transmission, sub-transmission and distribution. In this scenario there was no predefined injected power; instead an OPF is set up that maximises the capacity of distributed generation that can be connected for a given load level. The paper illustrates a number of important points:

- The contribution of distributed generation to the objective function is set as negative in the objective, therefore the optimum condition is to use as much distributed generation as possible.
- The OPF is run with DG set to different power factors which demonstrates the need to consider reactive power when optimising distribution networks. It is noted for example, that distribution networks are able to absorb greater injections from DG if they are operating at leading power factor. This helps to depress the voltage rise effect which otherwise limits the real power injection.
- Ideally transmission, sub-transmission and distribution systems must all be considered when attempting to optimise multiple distribution networks: the optimal solution for each individual distribution network when combined may lead to an infeasible solution for the overall system.

The problem of optimal location of distributed generation in a passive distribution network is extended in [3.28] to make use of the information contained in the Lagrangian multipliers of the optimal solution. This paper presents an approach that maximises the capacity of distributed generation in a similar manner to [3.27] discussed above. It then uses the vector of Lagrangian multipliers to identify which constraints, if marginally relaxed, would lead to the greatest increase in renewable generation capacity that could be added. This method can suggest where network investment should be targeted. A key point explored in the paper is that when using

Lagrangian multipliers, they give only the *marginal* effect of relaxing a constraint. The cost of the constraint as a function of the limit parameter will be, in general, non-linear and so the marginal effect will vary with the limit. The paper contrasts this with the 'lumpiness' of investment decisions. The value of the Lagrangian multiplier in the initial OPF solution should not be assumed to hold for the full range of the constraint relaxation.

This work on passive distribution networks deals with specified generation and demand conditions, and is relevant when considering firm wind connections. Firm generation is defined against pre-specified demand and generation conditions, namely low demand and high generation. Other situations which are not *worst case* are viable by default. The introduction of ANM, and particularly generation curtailment, invalidates this assumption. It allows an excess of generation capacity to be installed, and some of that capacity to be curtailed. This means that *generation* (rather than *capacity)* is limited by the *prevailing* conditions (rather than *worst case* conditions).

In reality wind power forms a significant proportion of distributed generation, and wind generation suffers from both low capacity factors and low correlation with demand. To fully analyse a wind energy scenario with non-firm distributed wind requires more than this single snapshot analysis.

One way to analysis wind generation and demand on a distribution network is through time-series analysis. Time-series analysis of power systems with distributed wind generation has been carried out in [3.29, 3.30] using power-flow analysis. These analyses aim to identify the duration curves for various network components and make use of these to identify particular curtailment levels, however they are not optimisation problems but simply apply power flow analysis to each time-step.

3.3.2 Optimal Power Flow for Active Network Management

The integration of ANM techniques into distribution networks over the past decade has been accompanied by a range of studies that have used OPF analysis. A range of objectives have been developed to study various aspects of ANM operation and design. This subsection highlights the key objectives and scenarios studied.

3.3.2.1 Distributed Generation and Active Network Management

The problem of maximising distributed generation capacity is an extension of the same problem in passive distribution networks discussed above. In these studies, the technologies associated with ANM must now also be modelled in a realistic way.

In [3.31] the first application of OPF to true ANM is made. The method is to solve an OPF for each individual time-step with a fixed capacity of distributed generation. The capacity of distributed generation is scaled by the availability of wind generation at each time-step to represent the available wind generation, and where required the OPF curtails distributed generation to maintain limits across the network. The results, in the form of output-duration curves show that the percentage of time that the highest levels of generation are achieved is reduced, whilst operation at lower output is unaffected. The OPF solution for each time-step is independent of the OPF for all other time-steps. This is a true representation of operating a wind curtailment scheme: as the maximum wind power available at each time-step is independent of the actions taken in any other time-step and the overall objective of maximising distributed generation is simply the sum of the optimal cases in each time-step. These assumptions hold true as long as there are no linkages between time-steps.

Whilst [3.31] analyses curtailment for a fixed capacity, [3.32] presents a method to maximise the capacity of non-firm generation subject to a maximum curtailment level. This paper is a significant advance in terms of optimisation using time-series analysis. The method aggregates time-series data for demand and renewable generation across a year into a 2-dimensional histogram. Bins are used to represent particular ranges of demand and generation. The dimensions of each bin are small enough that all data points can be represented by the mean values of those data points within the bin without too much loss of accuracy, an example of a 2-D histogram is shown in Figure 10. An OPF is solved which includes a representation of the network with the conditions relevant to each bin. In addition global variables combine each individual scenario with weighting functions that represent the fraction of data points in each bin. The result is a single optimisation problem that both solves multiple scenarios and links those scenarios together with global variables. In the study presented, demand and generation are divided into 10 bins each, giving a maximum of 100 scenarios. Analysis of a 1-year time-series for a distribution network in Scotland has 73 of the 100 bins containing data points. A global variable is created for each wind farm which tracks the total curtailment. A limit is defined on the maximum curtailment that can be applied to a particular wind farm. The optimisation therefore ensures that total curtailment is limited whilst maximising the total generation capacity within this constraint.

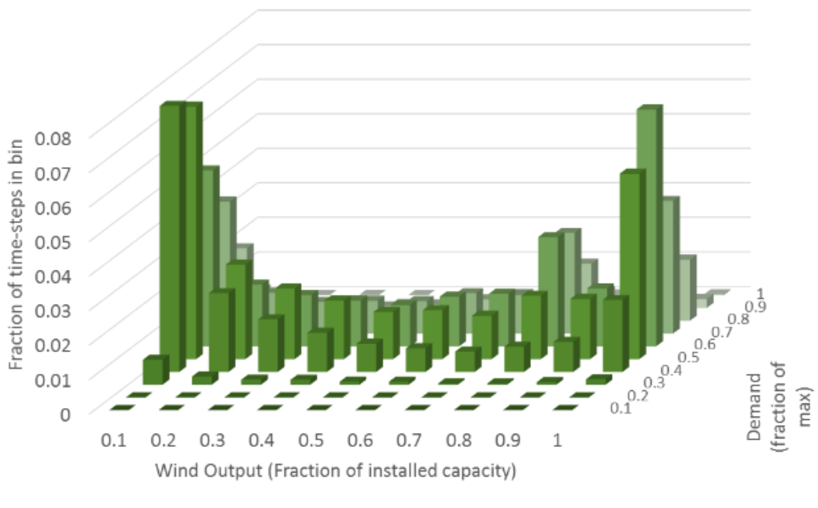

Figure 10: Example of the form of the 2-dimensional histogram used in reference [3.26].

This limit on the fraction of energy that can be curtailed is important. Without this the OPF will increase the capacity of distributed generation and simply apply excessive curtailments. This could lead to an 'optimal solution' including a large generation capacity that is curtailed all the time, a situation which is certainly not optimal from an investment perspective. The formulation presented allows the modelling of the case that a DNO guarantees that curtailment will not drop below a particular level.

Unlike OPF studies such as those discussed above in [3.31] in which each time-step is independent, placing a limit on the total curtailment across a year links the curtailment of distributed generation across time-steps. The value of total curtailment does not depend on the *order* in which periods occur but it does depend on duration curves of generation and demand. This type of intertemporal linkage can be thought of as a *soft* intertemporal linkage. This differentiates it from *hard* intertemporal linkages in which the order as well as the relative number of occurrences of particular conditions are considered.

The 2-dimensional histogram used in [3.32] is effectively a binned version of a combined load and generation duration curve. The method is further developed in [3.33] to include dynamic line ratings.

3.3.2.2 Maximising distributed energy generation

Two papers have considered the aim of maximising generation from distributed renewables - as opposed to capacity maximisation [3.34, 3.35].

In [3.35] a similar methodology to that in [3.31] is presented (two-dimensional binning of network conditions by demand and generation), however the objective function is now the maximisation of energy generated by distributed generation taking account of curtailment. The capacity of installed generation is a control variable of the optimisation. In this paper the maximum curtailment of a particular distributed generation is 10% of its available annual output. As before, this is required to ensure that the optimisation does not simply install excess capacity of generation and then curtail that generation.

In [3.34] an available resource is defined in advance that represents the maximum of each type of distributed generation resource that can be connected. The linear programming optimisation maximises the distributed energy generation harvested per euro of connection costs. It takes account of the capacity factors of various types and locations of generation, and the losses associated with the location of connection.

The objective of maximisation of energy generation is more directly linked to the overall aims of the power system than the objective of capacity maximisation. Capacity maximisation uses capacity as a proxy for renewable energy generation. With firm connection, or low levels of curtailment this holds true: there is a direct correlation between capacity and energy generation for wind generation (assuming all wind generation is exposed to the same wind resource). This is not true with non-firm capacity as greater installed capacities will lead to greater curtailment. Energy maximisation is very useful for developing operating strategies for systems with fixed capacities of non-firm wind, particularly when optimising the operation of technologies like energy storage which involve significant efficiency losses

3.3.2.3 Minimising the value of curtailment

Minimising curtailment is the inverse of maximising generation for a fixed capacity of distributed generation. A related concept is that of minimising the *value* of curtailment: wind generation at times of low electricity cost is less valuable than at time of high cost; curtailment at low cost times results in a smaller loss of value compared to the same quantity of curtailment at high price times.

In [3.36] a study is performed using OPF to control the levels of curtailment, the action of on-load-tap-changing transformers and the reactive dispatch of distributed wind generation. The objective in this study is to minimise the cost of curtailment, that is, the product of the quantity of curtailed energy and the current price of electricity. The study is run for a time-series of 1 hour time-steps for 1 year. Each time-step is a separate OPF and the cost of a unit of electricity is the same for all generators at the same time-step. The cost therefore acts only as a constant in the optimisation and will not affect the optimal solution (the same result can be obtained by removing the cost variable from the optimisation and multiplying the curtailment values by the electricity prices during post-processing). This simplification is not possible when using multi-period optimisations.

This process of considering the *value* of wind generation is an important idea that is returned to in Chapter 4.

3.3.2.4 Minimising system losses

Minimising system losses has already been discussed in terms of generic OPF problems. Its formulation is relatively simple - minimise the total quantity of generation, and if demand is fixed then the only flexibility is in reducing losses. When considering traditional generation types, minimising losses is an effective way to minimise the use of fuel. When considering systems with wind and other renewable generation the importance of losses must be carefully defined. Wind generation is an example of a technology without a traditional fuel and almost zero marginal costs. The generation of electricity from wind and the subsequent 'loss' of part of that electricity can be considered as of considerably less importance than the loss of fossil-fuel generated electricity.

With low penetrations of distributed generation, new generators can be sited specifically to reduce power flow losses [3.26, 3.37]. Variations in the effect of generation at specific positions on the network are investigated in [3.38] and used in an OPF in [3.39].

In [3.40] the methodology for using OPF with curtailment of distributed generation (already discussed in [3.32] above) is applied to the problem of loss minimisation. The introduction to the paper makes the important distinction between minimising *power* losses for a specific case (notably maximum demand / maximum distributed generation output) and minimising *energy* losses. *Energy* loss minimisation requires an accurate representation of the range and distribution of *power* across a period of time. This paper minimises energy losses from a network using only firm generation.

It shows that distributed generation can significantly reduce network losses. In the case study presented, if demand and generation are both treated as variable (i.e. using the multi-period approach discussed above in reference to [3.26]), energy losses can be reduced by 40% through the use of distributed wind generation if it operates at unity power factor. The incorporation of co-ordinated voltage control raises this value to greater than 50%. The paper goes on to note the tension between the objectives of maximising renewable generation and minimising network losses. The paper proposes a modified objective, which it defines as harvested wind energy minus losses. The resultant quantity can be described as the *useful renewable generation*. The paper concludes by proposing that losses from renewable generation with their low or zero carbon impact should be differentiated from lost fossil fuel generation.

Other studies aiming to minimise losses are [3.41] where the cost of losses is minimised via OPF, and through other methods in [3.42, 3.43].

3.3.2.5 Remarks on the objective of minimising system losses

The tension noted in [3.41] between losses and renewable generation is an important consideration when optimising networks. The role of losses should be considered in comparison to generation curtailment. Both network losses and curtailment can be thought of as 'losses' in the broad sense. In the case of the curtailment it is the loss of the opportunity to generate electricity, an opportunity that cannot be saved to a later time. Once the wind turbine has been built and is available, there are (almost) no costs associated with generating the electricity, so curtailment is very similar to network losses. In a system with fossil fuel and wind generation operating with an aim of reducing reliance on fossil-fuel generation, the wind generation should be utilised even if it leads to higher network losses than if it were curtailed: the high-level objective is maximised.

In Chapter 4 the difference between maximising wind generation and maximising the effect of wind generation is discussed and forms an extension of this issue, it becomes particularly relevant when combined with energy storage which has significant operating losses.

3.3.2.6 Managing voltage in ANM schemes

Voltage can be controlled by a number of methods: on-load-tap-changing transformers, reactive power compensation and generator power factor control. These can be directed towards objectives such as cost minimisation. In [3.44] the use of reactive power devices to minimise load curtailment in a generic OPF is presented. Reactive power devices are modelled as either phase shifters or series compensation. Phase shifters are modelled by constraining reactive power injection at a node, within limits. Series compensation is taken to be an integral part of the network infrastructure and the susceptance of links between nodes are adjusted to take account of it. These susceptances are made into control variables in the OPF and their range of operation is also limited.

An in-depth look at the role of co-ordinated voltage control for ANM is given in [3.45] and compares it with a distributed voltage control method. In this formulation the power angle is the control variable. A local voltage-control method is developed where a power factor controller responds when the local voltage at the generator's location moves beyond specified limits. At this point the power angle changes from a fixed parameter to a control variable in order to maintain the voltage at its threshold. The second method investigated is a distributed voltage-control method in which the power factor angle can be set to any value between fixed limits at all times. The OPF adjusts the power angle to maximise the capacity of distributed generation across the network.

In [3.39] reactive power compensation is modelled by constraining limits placed on the reactive power generated at each node. Tap-changing transformers are modelled by setting minimum and maximum limits. The co-ordinated voltage control scheme is implemented by allowing the variation of 1 tap-changing transformer, whilst minimising energy curtailment. In [3.35] on-load-tap-changing transformers are constrained using their output voltages rather than transformers settings, and generators are given the ability to control their power factor within limits.

3.3.2.7 Scheduling energy storage and Flexible demand

Energy storage and flexible demand are technologies which must be analysed across a time-horizon. They cannot be fully represented at one time without analysis of operation at other times. Single period OPF formulations therefore cannot provide a full analysis of these intertemporal technologies. However there are some attempts to make use of OPF to study them in the literature.

One way in which single-time-step OPF can be used to assist with the scheduling of energy storage is presented in [3.46]. Here an OPF is performed for each time-step across a year to identify a time-series of curtailment from non-firm generation. The sizing and location of the energy storage is defined relative to this time-series. An envelope of operation is pre-defined for the storage which states at what time-step the charging and discharging of the store is permitted (night time and day time respectively). Finally, a second OPF is run using these predefined constraints. The role of the second OPF is to create a schedule for the energy storage to follow that will minimise the overall cost of energy.

Demand flexibility can be provided by a number of models. It can be broken down into two elements: flexibility in total energy demand; and flexibility in the timing of delivery of energy. Single-time period OPF formulations, using a maximisation of social welfare objectives are well placed to deal with the first of these [3.24, 3.25]. Dealing with flexibility in timing of delivery requires analysis over multiple-time-steps.

The short comings of single-period OPF for analysing intertemporal technologies is significant. A key objective of this thesis is to develop tools capable of modelling energy storage and flexible demand. Particularly the extension of OPF to cover multiple time-steps. In Section 3.4 progress to date towards this aim is discussed.

3.3.2.8 Variable line ratings

The maximum safe capacity of overhead lines depends on ambient atmospheric conditions and on the recent history of power flow along the line. Taking account of this in variable ratings for overhead lines is a technique being incorporated into some power systems.

In [3.33] variable line ratings are modelled using the method of 2-dimensional binning described in Section 3.3.2.1. The study assumes that the maximum safe power flow capacity is correlated to wind speed. A 3-dimensional histogram is created with the dimensions defined as wind power generation, demand and wind speed. Note that wind speed, whilst related to wind power through the wind farm power curve, is a significantly different time-series. At each wind speed, a specific value of maximum power flow through the dynamically rated lines is applied. This provides an example of adjusting line rating according to current conditions, a further advancement would be to allow the line limits to become intertemporal variables through dependant on the recent power flow history.

This section has reviewed some of the important work using OPF techniques to optimise active network management and some of the associated technologies and techniques. It has investigated extending distributed generation towards multi-period OPF and makes clear in its discussion of energy storage and flexible demand the need for such techniques.

A key conclusion of the work reviewed so far is the need to deal effectively with *hard* intertemporal effects, that is, effects which depend on the order in which particularly network conditions apply. Examples noted include energy storage and flexible demand. This extension to full DOPF is developed in the following section.

3.4 Multiple time period optimisation

Optimal Power Flow is an optimisation process typically applied to a single set of network conditions; these represent conditions on the network for a particular snapshot in time. As with any mathematical programming problem, anything external to the mathematical formulation of the optimisation cannot influence the optimal solution. So traditional implementations of OPF cannot consider the past or the future.

In the review of the application of OPF to distribution networks, an extension of this concept has been discussed, which is presented in [3.31, 3.33, 3.35]. The methodology is referred to as *multi-period* OPF. The method works by creating separate power flow variables to represent a range of network cases, together with some global variables which link the different cases together. The method allows different network conditions to be combined in a single optimisation. In these formulations the order in which the network conditions occur is not taken into account. Because the total curtailment does not depend on *when* the curtailment occurs, curtailment limits are an example of a soft intertemporal constraints.

The limitation of this method is that there are a range of technologies whose operation depends on the order of network conditions as well as their frequency. For example, energy storage requires alternating periods of charging and discharging and cannot be operate with a single 6-month charge followed by a 6-month discharge. Such constraints, where order is important are referred to as *hard* intertemporal constraints.

A more direct multi-period OPF implementation exists and has developed from the problem of hydrothermal generation schedule coordination [3.47]. This method creates a set of power flow variables for network conditions at each time-step from a time-series and links these sets *in order* through the use of a set of global or *intertemporal* variables. These intertemporal variables together with associated intertemporal constraints model technologies such as energy storage which must be optimised according to ordered time-series data. This framework is called *Dynamic Optimal Power Flow (DOPF)* in this thesis in line with its early implementation.

The original development of DOPF extends OPF, and was an improvement on existing methods of solving the problem of coordinating hydro resource with thermal generation such as dynamic programming [4.48](for example presented in [3.49]).

The concept of a DOPF is to create a set of power flow variables for each time-step, together with additional intertemporal variables and constraints (which are functions of the state and control variables at each time-step). The general formulation of OPF as given in equations (3.1) – (3.3) is extended to the following:

$$\min\left\{\sum_{t=1}^{t_n} f(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t))\right\} \tag{3.7}$$

subject to original OPF constraints applied at each time-step, t, where t runs from 1 to the total number of time-steps t_n:

$$\boldsymbol{g}(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \boldsymbol{0} \;\forall\; t = 1,2, \dots, t_n \tag{3.8}$$

$$\boldsymbol{h}(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) \leq \boldsymbol{0} \;\forall\; t = 1,2, \dots, t_n \tag{3.9}$$

and to intertemporal DOPF constraints:

$$k(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \boldsymbol{0} \;\forall\; t = 1,2, \dots, t_n \tag{3.10}$$

$$l(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) \leq \boldsymbol{0} \;\forall\; t = 1,2, \dots, t_n \tag{3.11}$$

where $\boldsymbol{\tau}$ are defined as the additional intertemporal variables and all variables ($\boldsymbol{x}, \boldsymbol{y}, \boldsymbol{z}$ and $\boldsymbol{\tau}$) can in general take different values at each time-step. The objective function is minimised across all time-steps within the same optimisation. The functions $\boldsymbol{k}$ and $\boldsymbol{l}$ are intertemporal constraints which link variables at different time-steps and the intertemporal variables.

The first example of a DOPF in the hydrothermal context was proposed in [3.50]. This paper described the difference between the long-term hydrothermal optimisation taking account of seasonal variation, and the short-term day-ahead problem. The short-term problem has the advantage that the variations in the volume of water stored in large reservoirs (and therefore pressure variations on the turbines) can be neglected. The proposed method combines the power flow equations of OPF with the intertemporal constraints of drawing stored energy from hydro-reservoirs. In [3.51] Newton's method is used to solve a multi-time step OPF, and the large scale nature of the problem is discussed, leading to the use of sparse matrix solution techniques. The short-term hydrothermal formulation in these studies assumes hydro-electric units have no fuel costs and the power generated is a function of water flow and hydrostatic head. The energy drawn from the reservoir is an intertemporal variable as it depends on power variables at multiple-time-steps. The limit on the energy drawn is an example of an intertemporal constraint.

The work in [3.51] is an example of one single, large-scale optimisation. To improve computational efficiency a number of DOPF methods for hydrothermal coordination split the problem using decomposition into two sub-problems. For example in [3.52] the method of Bender's decomposition [3.53] is used to solve the hydrothermal DOPF problem, and in [3.54] it is used to combine DOPF with the unit-commitment problem

The hydrothermal problem is an example of energy storage in a power system. Traditional hydro-plants represent 'one-way' storage: energy can be stored until required and the store cannot be re-charged from the power system. Pumped-hydro stations on the other hand represent two-way storage.

A second smart-grid technology with relevance to ANM to which DOPF has been applied is demand flexibility. In [3.55] a DOPF is set up to model demand-side management. The study states that it maximises social welfare by defining the consumer benefit function as well as the supplier cost function. In addition to applying a single demand curve during individual time-steps the method defines the concept of 'cross-time' elasticity so that price during one period can affect demand during a separate period. The case study does not however make use of this concept.

The study differentiates clearly between energy and power when considering demand. Demanded power is constrained at each time-step and energy is constrained across the time-horizon of the optimisation through an equality constraint which ensures that the total energy demand within the optimisation horizon is fixed. The method is combined with hydrothermal co-ordination in [3.56] and [3.57].

These papers state that they maximise social welfare through the use of the demand benefit function. The consumers in these models minimise their payments by flexing *when* they purchase energy. The formulation does not allow consumers to forgo energy entirely at any price, as such the method does not reach a full *maximisation of social welfare* as usually understood in microeconomics.

In [3.58] the DOPF formulation of [3.55] is applied to the specific example of interruptible load management. This paper models an incentive provided by a utility company for the offer of interruptible demand. The incentive is only paid on the actual interruptions rather than simply the availability of reduction, and the DOPF includes the ability to dispatch load interruptions jointly with conventional generators.

The application of DOPF to systems containing wind generation allows the variability of wind generation output to be fully modelled through a time-series. An important constraint for power systems with high penetrations of variable wind generation are the maximum ramp rates of conventional generators. A heuristic DOPF method known as the Shuffled Frog Leaping algorithm is used in [3.59] to optimise the real and reactive power of wind farms in a network with the objective of minimising fuel costs. The optimisation takes account of the valve-point effect and ramp rate limits of conventional generation. A similar problem is solved via particle swarm optimisation in [3.60]. In both cases the dispatch is formulated as a mixed-integer optimisation that therefore cannot be solved via non-linear programming techniques.

A combination of wind generation and energy storage in a full DOPF formulation is presented in [3.61] (referred to as multi-period OPF). This paper treats wind power as dispatchable up to the current maximum wind generation availability. The power system includes both wind and traditional generation (the latter with associated fuel costs). The objective of the DOPF is to minimise operating costs. This paper introduces a number of issues that are key to the modelling of energy storage and are developed in this thesis:

- Constraints on storage power at each time-step are imposed limiting the store to a maximum (positive) and minimum (negative) limit where negative values and represents charging of the store.
- A further set of constraints is required to ensure that the energy storage unit does not exceed its maximum and minimum state of charge during each time-step of the optimisation. This limits operation of the store to within its *energy* capacity.
- An intertemporal equality constraint is introduced to ensure that the sum of injections to the power system from the energy storage unit is zero over the optimisation-horizon. This ensures that energy storage does not create or use energy. The paper states that this constant "limits the efficiencies for charging and discharging to be equal" ([3.61], page 86). However, the formulation suggests that the charging and discharging efficiencies are both 100%. If this were not the case and the energy storage unit involved inefficiencies, the quantity of energy discharged to the network must be less than that charged into the energy store. The issue of storage efficiencies has yet to be fully resolved in the literature and forms a contribution of this thesis.

3.4.1 Applying Dynamic Optimal Power Flow to distribution networks

The DOPF papers described so far discuss either generic power systems or large transmission networks. The application to smaller-scale devices has been proposed in a number of papers, together with some of the specific challenges of distribution network optimisation.

In [3.62] a real and reactive power DOPF is proposed that is relevant to distribution networks with distributed generation and energy storage. The method is similar to that in [3.61], with the addition of reactive power provision from both wind energy and storage. The paper gives a fuller description of energy storage efficiencies than in [3.61]. In this study the charge and discharge efficiencies of energy storage are explicitly linked to the stored energy. However, the paper chooses to pre-define charging and discharging periods based on a fixed on-peak / off-peak price profile. The purpose of this is to avoid having a charging and discharging variable at each time-step which could lead to redundancy in the solution, with both charging and discharging variables being operated in a way that cancel each other out. Pre-defining exactly when charging and discharging can occur places a significant limit on the usefulness of the method in networks where generation curtailment can occur at any point during the day.

A key contribution of this thesis is to remove the current limitations on modelling energy storage relating to efficiency and pre-defined charging/discharging time-steps.

The combination of both demand flexibility and energy storage is tackled in [3.63]. A DOPF is run with and without the intertemporal technologies, and the results show a reduction in the costs of congestion on the network and a reduction or removal in load shedding when flexible intertemporal energy technologies are utilised. The paper does not present a mathematical framework of the optimisation.

3.5 Contributions and limitations of existing Optimal Power Flow analysis of distribution networks

The review of the literature on OPF-based optimisations relevant to the operation of future ANM enabled distribution networks reveals a significant recent interest in the field. The work done with single-period OPF has focused on planning the optimal sizes and locations of distributed generation. Many of the factors relevant to ANM schemes have been incorporated in these OPF formulations: generation curtailment;

dispatchable reactive power from distributed generators; co-ordinated voltage control.

An important step towards intertemporal modelling of ANM scheme has been the development of OPF formulations that allow the incorporation of 'soft' intertemporal limits such as overall limits on curtailments. These methods however are not able to deal with full 'hard' intertemporal problems where the order of events is important as well as the relative abundance.

The development of DOPF for hydrothermal co-ordination has been adapted to the case of flexible demand and a generic form of energy storage. The role of the storage efficiency and the difference between charging and discharging efficiencies has been briefly addressed in the existing literature but a full model of energy storage has yet to be presented. This is a significant gap in the literature and one that this thesis addressed in Chapter 5.

A key part of ANM discussed in Chapter 2 which has yet to be introduced in an optimisation context is principles-of-access. This defines the terms on which distributed generators have access to limited network capacity. The *priority* principle-of-access in the form of LIFO has already been implemented in the Orkney ANM scheme [3.64] and as such it is important that these arrangements can be incorporated into optimisation procedures for ANM. The formulation of principles-of-access for non-firm generation is developed in Chapter 5 of this thesis.

Very little attention has been paid to the optimisation of flexible demand in an ANM context. As discussed in Chapter 2, flexible demand is likely to form an integral part of the operation of smart distribution networks. The small number of existing studies into demand flexibility in general need to be developed and applied to the ANM context, for example to represent the developments planned for the Shetland ANM scheme (See Section 2.3.2).

Finally, little attention has been paid to the significant information contained in the Lagrangian multipliers of an optimal DOPF solution. In OPF, the multipliers on nodal-energy balance play an important role in terms of nodal pricing, and the multipliers on inequality constraints provide *shadow prices* for those constraints. In a similar way, the Lagrangian multipliers on intertemporal constraints can provide useful information on the constraints associated with the planning and operation of energy storage and flexible demand. The extension of economic analysis of optimal solutions to OPF to optimal solutions to DOPF forms the basis of Chapter 6.

As well as the development of specific advancements to OPF and DOPF, an important extension of the existing literature is to ensure that they are applied to the integration of wind generation. This is currently one of the biggest driving forces behind the development of active distribution networks. As noted in the introduction to this chapter, exploring how to extract value from wind generation is a major concern and this involves tackling the challenges of intermittency and uncertainty. The method of DOPF identified in this chapter provides a useful tool in this challenge as it has the ability to directly include intermittency in its formulation. Once developed, the method can be used to study differences between forecasts and realised wind generation time-series and provide information on the issue of uncertainty. The direct application of the method to a distribution network with a significant capacity of wind generation is presented in detail in Chapter 7.

In [3.65] (page D23) it is noted that OPF offers the decision phase of ANM a truly holistic view, this is true of existing schemes that deal with static optimisation and non-intertemporal technologies. This thesis proposes that DOPF can provide a similarly holistic view to second-generation ANM schemes including intertemporal technologies.

3.6 Conclusions

This chapter has provided a detailed review of OPF and its application to distribution networks. It explores the role that OPF can play in planning passive distribution networks, and in planning and operating ANM schemes. The requirement for tools which can optimise across time as well as managing network effects is identified. DOPF, initially developed to solve the problem of hydro-thermal generation coordination is identified as a tool to be developed.

The majority of existing ANM technologies are well modelled in single time-step OPF, including coordinated voltage control and generation curtailment. However, principles-of-access for non-firm generators are an exception and do not form part of existing studies, therefore new formulations are needed.

Existing literature on DOPF is reviewed, and this highlights studies that have directed it towards problems involving non-firm generation, energy storage and flexible demand. It also notes however, that there is a significant gap in the literature in this area. The existing studies are found to be minimal and do not provide full flexibility to the optimisation – a gap that is met by this thesis. In particular DOPF formulations are required that: fully model the efficiencies and flexibility provided by energy storage; and detail the development of flexible demand.

A contribution of this thesis is to fill these gaps and provide a detailed example of the application of the developments. In the following chapter a simplified linear-programming optimisation is used to study some general aspects of energy storage in ANM schemes. This leads to the development of the full DOPF formulation in Chapter 5 which also includes principles-of-access, a full model of energy storage and models flexible demand in a similar way to energy storage. Whilst Chapter 5 provides the framework for using DOPF to schedule intertemporal technologies, Chapter 6 develops a theory of Dynamic Locational Marginal Pricing based on DOPF.

Finally, a detailed application of the methods and analysis of the results for an islanded distribution network are discussed in Chapter 7.

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Chapter 4: Optimising an active distribution network with non-firm wind generation – an initial study

ACTIVE NETWORKS PROVIDE a degree of control which can be used in numerous ways. One objective of such schemes is to extract the greatest benefit from wind generation. Intertemporal flexibility in an Active Network Management (ANM) scheme can be used to manage the curtailment applied to distributed wind generation with non-firm contracts. The benefit of wind generation can be defined in terms of raw energy generated, its ability to offset other forms of generation or as an economic measure in monetary terms. The action of intertemporal technologies can then be optimised to maximise the specified benefit.

Detailed modelling of distribution networks must include consideration of the interaction between distributed generator outputs, local demand and the network infrastructure. Power flows are governed by Ohms Law for AC systems and the principle of conservation of energy. To fully model these power flows a full AC, non-linear network model should be used which takes account of real and reactive power, currents and voltages. Optimising such a model is the role of a full AC Optimal Power Flow (OPF) for a single time-step, or Dynamic Optimal Power Flow (DOPF) across multiple time-steps. Such an optimisation is complex and time-consuming, and the development and use of DOPF is the subject of Chapters 5 - 7 of this thesis. This chapter uses a simpler approach to carry out an initial study that gives a number of broad, general results relevant to energy storage in ANM schemes. These results are developed further in later chapters.

The chapter develops an energy-balance linear programming optimisation which aggregates the distribution network to a single-bus with a thermally constrained link to the transmission network. The model aggregates demand and generation across the whole distribution network at each time-step. By ignoring reactive considerations, these simplifications allow linear-programming rather than non-linear programming to be used. The results for the simplified system allows beneficial analysis and are expanded upon with more sophisticated models presented later in the thesis

The chapter begins by discussing and defining the objective of maximising the benefit of non-firm wind generation in an ANM. It then develops a single-bus mathematical model of a distribution network that includes energy storage.

This is followed by a case study created from historical values for wind generation and distribution network demand. The case study is used to produce initial results and illustrate a range of important issues. It includes:

- Examples of optimal charging and discharging schedules for energy storage
- Economic analysis and an example Net Present Value calculation for energy storage
- Renewable subsidies
- The marginal value of energy storage.

Energy storage is modelled in the case study as an example of intertemporal flexibility, and the extension to flexible demand is discussed at the end of the chapter; inclusion of the flexible demand into the mathematical modelling is left to Chapter 5.

4.1 The benefit of distributed wind generation

A simple measure of the benefit of distributed wind capacity is the quantity of energy that is generated. However, it is not the goal of any power system simply to generate electricity from wind turbines for its own sake. Instead a more subtle measure of the *benefit* is needed that measures the ability of wind generation to its ability to meet the wider goals and objectives.

In the operational context, wind generation can reduce generation from conventional fossil-fuel plants and therefore reduce fuel usage and carbon emissions. This has a financial benefit: reduced costs of operating the power systems. Both financial and carbon benefits relate to the *effect* of wind generation rather than simply the quantity of electricity generated.

A number of papers discuss a related concept – the *value* of wind generation. In [4.1] value is defined as 'the sum of revenues by unit of energy if all wind power production were sold in the power exchange', which means the average price per MWh produced by wind power. The value is defined in [4.2] to include the effect of saved fuel costs due to wind power and the saved emission costs, while in [4.3] the capacity value of wind is added to the equation.

These papers make specific use of the term *value* as meaning the 'the money worth of an asset or product' as defined by the Collins dictionary of economics [4.4]. This thesis uses the concept of value, but also uses metrics based on non-monetary measures such as directly measuring the reduction in conventional energy generation. The thesis also concentrates on the operational aspects of wind capacity and intertemporal technologies and, with the exception of Section 4.4.8, does not consider capital cost. For these two reasons the term benefit is used to discuss either the monetary or non-monetary operational worth of an asset or product.

In this thesis three measures of the benefit of wind capacity are discussed:

- **The benefit of wind capacity defined as the quantity of wind energy generated.** This simple metric is useful when considering the ability of a power system to contribute to renewable energy targets. Currently, under the EU 20-20-20 targets the UK is required to generate 15% of total energy from renewable sources [4.5], and meeting that target simply involves the measuring the quantities of electricity (or energy) generated.

- **The benefit of wind capacity defined as the quantity of conventional generation, or the displacement of import to the distribution network.** This definition differs from the previous one in that it defines benefit in terms of the effect of wind generation rather than simply its generation. The difference is made particularly clear when considering energy storage inefficiencies: if a storage device is only 50% efficient only half of the increased wind generation used to charge the store is returned to the network, and this is the resulting *useful* energy. This metric concentrates on the *useful* wind energy generated.
- **The benefit of wind capacity is defined as the total cost of import to the network that is offset**. This third definition weights each unit of electricity imported to (or exported from) the network by the current, external market price. In an ideal market the market price is related to the marginal cost of production. Reducing import during a period of high price means directly reducing generation at a high cost generator. This is more beneficial in terms of reducing the cost of operating the power system than offsetting import at times of low price.

Distributed non-firm wind generation on its own has benefit to the power system, and the addition of intertemporal technologies can increase this benefit. In addition there may be a benefit from the intertemporal technology itself. For example, an energy storage device can carry out price-arbitrage when there is no curtailment of wind generation. The ability of energy storage to access multiple revenue streams is noted as an important factor in the financial viability of expensive energy storage [4.6].

Examples of the benefit of energy storage devices to a power system include its ability to perform load following, peak shaving, reserve provision, investment deferral and mitigation of variability [4.6, 4.7]. Energy storage technologies of the scale required for bulk time-shifting of energy are currently expensive. Estimates of the cost of

Sodium-Sulphur batteries are in the range of £1.3-£2.5 million [4.8], [4.9] per MW and this expense has limited the application of energy storage.

The study in this chapter considers two benefits of energy storage: the additional benefit from wind generation and benefit from price-arbitrage. Arbitrage is defined as the trading of electricity between times of low and high price. The total benefit created by the energy storage devices is a combination of the additional benefit of wind generation and the benefit of arbitrage.

4.2 A single bus model of a distribution network

The concept of a single bus network is shown in Figure 11. It is defined by its aggregated demand, aggregated distributed generation and power flow capacity along the import / export line linking it with the wider power system. For most distribution networks this link will be with the transmission or sub-transmission network and so it will be referred to as the *transmission connection point*. The transmission connection point can consist of power lines or cables or the transformers required to step the voltage up to transmission level. The terminology reflects the context of the study, however it should be remembered that the simple model is equally valid for use in micro-grids and their link to the greater distribution network.

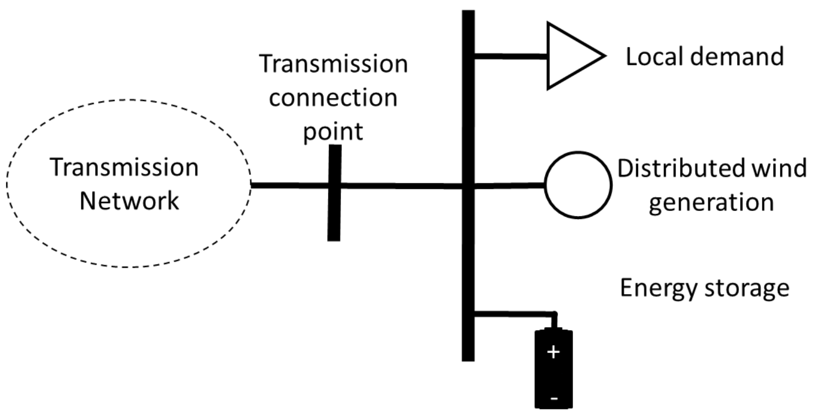

Figure 11: *S*ingle bus representation of a distribution network with demand, distributed generation and energy storage

The single bus network ignores the internal structure of the distribution network including voltage and thermal constraints within the network itself. The action of network components is only limited by the flow of real power through the transmission connection point. In addition to this simplification, if reactive power is ignored the system becomes one of energy balancing within the constraints of the transmission connection point.

Whilst these assumptions represent a significant simplification over real distribution networks, this model has relevance for three reasons: (1) a single bus distribution network is itself a good model for some distribution network designs, for example if distributed wind generation is well spread throughout the distribution network so that the key constraint is the export from the distribution network itself; (2) in some distribution networks, for example the Orkney ANM scheme, thermal limits are the main constraint leading to congestion - and as such models which ignore voltage can still produce accurate results; (3) where the majority of distributed wind generation is connected close to the transmission connection point and not towards the end of radial feeders.

A final assumption used in this model, and throughout the discussion on transmission-connected distribution networks, is that demand and distributed generation is small relative to the size of the total electricity market. This justifies the assumption that the action of generators, demand or flexibility within the distribution network do not affect the price of electricity in the market and as such the price can be considered as exogenous to the models.

The results discussed in this chapter will be revisited in later chapters using the full DOPF model.

4.3 Description of the single bus model

This section develops the linear-programming optimisation formulation for the single bus network. The objective of the optimisation is the maximization of revenue generated by energy storage connected to a distribution network. In this scenario the action of the energy store represents the only control action available to the ANM scheme beyond curtailment of non-firm generation. Without energy storage, the curtailment is fixed and can simply be calculated from demand and generation values for each time-step. The energy store can time-shift generation from a wind farm with a non-firm connection to avoid curtailment and it can perform price-arbitrage with an external market. Arbitrage in this context means the ability of energy storage to charge when the market price is low and discharge when the market price is high. Throughout this thesis the term 'otherwise-curtailed generation' is used to mean the extra wind generation that an energy storage device allows.

The action of the storage under the objective *maximise storage revenue* will be shown to be the same as minimising net payments from elements in the distribution network out to the external markets. This involves maximising the financial value from wind generation and in addition making use of market price differences to carry out arbitrage. The relationship between maximising storage revenue and achieving the greatest benefit from wind generation is returned to in section 4.5.

The optimisation problem consists of a network model, energy storage model and input time-series; data from these are collated into a linear programming problem. The components are described separately and are followed by a description of how the algorithm is implemented.

4.3.1 Network model

The simplified network scenario that modelled is shown in Figure 11. The components of the scheme are:

- Local demand time-series.
- A transmission connection point with a fixed power carrying capability.

- Firmly connected wind generation, P_{firm}, up to the maximum capacity calculated from the annual minimum demand, P_{dem}^{min}, and the transmission connection point, P_{tcp} :

$$P_{firm} = P_{tcp} + P_{dem}^{min} \tag{4.1}$$

- Non-firmly connected wind generation, which will be curtailed when the total generation on the network would otherwise exceed the sum of export capacity and current local demand.
- Energy storage with the ability to trade with the spot market and access the curtailed generation from non-firm wind farms.

4.3.2 *Energy storage model*

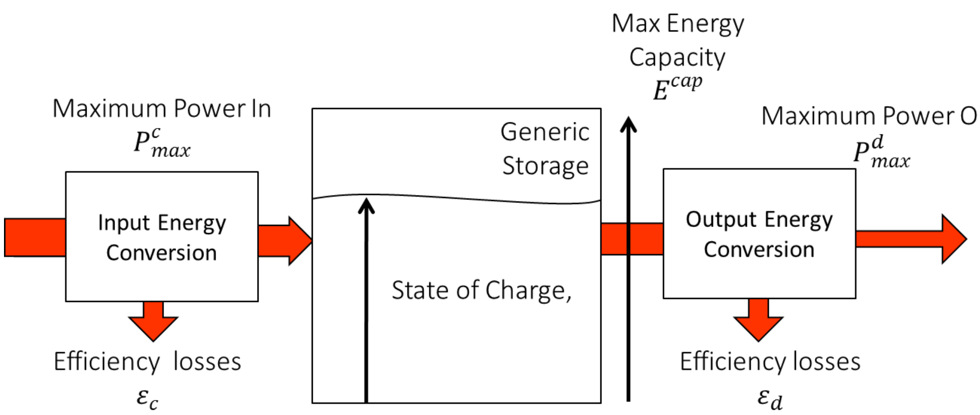

Figure 12: Generic model of an energy storage system.

A generic energy storage model is shown in Figure 12 and can be used to model most forms of energy storage devices. It consists of an energy conversion unit for charging and for discharging. For many applications these will be the same unit and may represent, for example, the power electronic convertor on a battery. Other systems – such as hydrogen storage – will require separate energy conversions systems for charging and discharging. Both charging and discharging will incur losses, and the product of the efficiencies for charging, ε_c, and discharging, ε_d, give the round trip efficiency of the energy store, ε_{rt}. The energy store itself has a maximum and a minimum state of charge. Throughout this thesis 'state of charge' is defined as a fraction of the maximum energy storage capacity.

It is important that the efficiency losses are realistically modelled. The round trip efficiency represents the fraction of charging energy returned to the network. For many applications, this level of detail is sufficient. In this thesis the need for the separate charge and discharge efficiencies are discussed. The effect of round trip efficiencies on the value of an energy storage device is discussed in Section 4.4.4 and the effect of varying the charge and discharge efficiencies is discussed in Chapter 5.

4.3.3 Input time-series data

The model uses historic time-series data for network demand, wind generation and market price. A time-series gives values for demand or generation for each *time-step* which is assumed to be an average value that holds for the duration of that time-step. The number of time-steps multiplied by the length of each time-step gives the optimisation time-horizon. In an electricity market the most appropriate time-step length to use is the length of a market trading period. The model developed here is based on UK data and therefore each time-step has a half-hour duration.

For the purposes of this case study, it is assumed that all distributed wind generation in the model is exposed to the same wind profile and as such there is perfect correlation between the potential output of all firm and non-firm wind generation capacity.

The availability of curtailed wind generation is one input to the optimisation. For the simplified one-bus, real power model used in this chapter, curtailment is used to maintain the export of power through the transmission connection point within limits. As such, curtailment *without energy storage* can be calculated for each time-step using the following procedure:

1. Calculate the energy flow through the transmission connection point, $P_{tcp}^{no-curt}$, assuming no energy storage and no curtailment (see Figure 13 below for an illustration):

$$P_{tcp}^{no-curt} = P_{dem} - P_{wind} \tag{4.2}$$

   where, $P_{tcp}^{no-curt}$ is the power flow through the transmission connection point without curtailing non-firm wind, P_{dem} is the aggregate demand and P_{wind} is the aggregate wind generation.

2. The required curtailment, P_{curt}, to maintain the limit can be calculated using:

$$P_{curt}(t) = \begin{cases} 0 & \text{if } \left|P_{tcp}^{no-curt}\right| < P_{tcp}^{max} \\ \left|P_{tcp}^{no-curt}\right| - P_{TL}^{max} & \text{otherwise} \end{cases} \tag{4.3}$$

   where $P_{tcp}^{max}$is the limit on the power flow through the transmission connection point and P_{curt} is the curtailment applied to aggregate wind generation .

Equation (4.3) can be applied separately at each time-series of a simulation to create a time-series, $P_{curt}(t)$, which then forms the input to the optimisation of the storage profile.

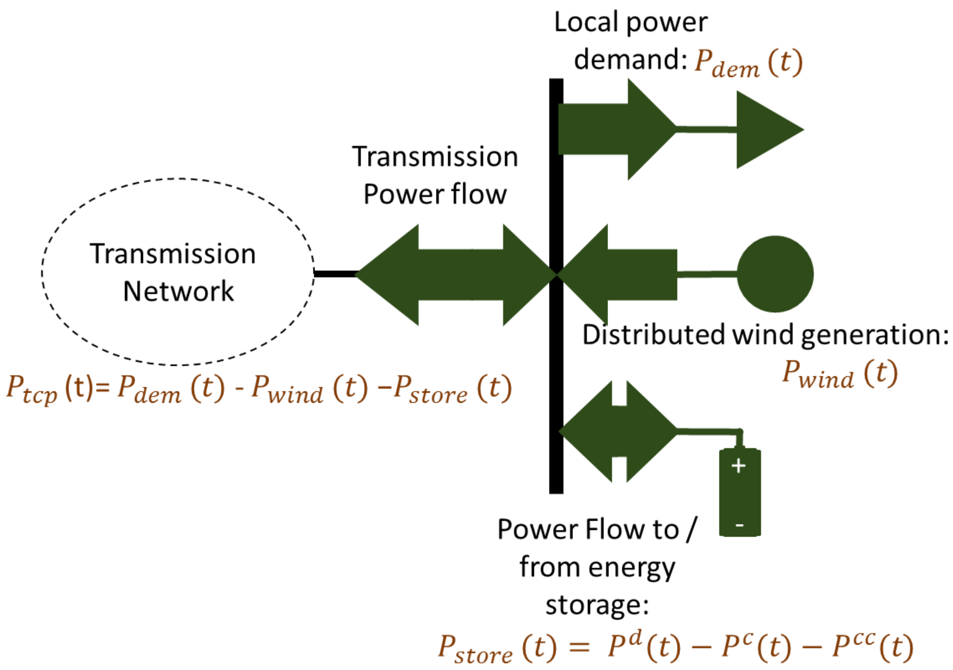

Figure 13 : Illustration of power flow to / from the one bus distribution network. $P_{store}(t)$ is defined as positive when discharging to the network and the transmission power flow $P_{tcp}(t)$ is defined as positive when importing to the distribution network.

4.3.4 Mathematical formulation

The optimisation is constructed to maximise the revenue generated by the energy storage. Energy storage has three actions that it can take:

- it can charge directly from the energy market, paying the current market price for the power used;
- it can charge by using excess wind generation that would otherwise be curtailed, paying the wind generators a *curtailed price*;
- it can discharge to meet either local demand or export via the transmission connection point and be paid at the current market price.

These three actions are treated separately in the optimisation, and each has its own variable for each time-step. Obviously one action affects the ability to apply the others, and ensuring that the combined result is physically viable and sensible is achieved via constraints.

The objective function

This objective is defined as:

$$f = \max \Delta t \sum_{t=1}^{n_t} \left\{ \left(P^d(t) - P^c(t) \right) \pi(t) - P^{cc}(t)\, \pi_{curt}(t) \right\} \tag{4.4}$$

Where $P^c(t)$ and $P^d(t)$ are the power charged from and discharged to the grid during time-step t respectively and valued at the current market price, $\pi(t)$. The quantity $P^{cc}(t)$ is the power charged from otherwise-curtailed wind generation and $\pi_{curt}(t)$ is the *curtailment* price: the price paid to the generator for otherwise curtailed energy. The objective function, *f,* includes a sum across all n_t time-steps of length Δt he objective function is simply the sum of revenues minus the sum of costs of operating the energy storage over the optimisation horizon.

Network constraints

In this formulation, demand is fixed and inflexible. As such it is simply the historical time-series value at each time-step. Figure 13 illustrates the power flows into and out of the single bus network from the various components. The key constraint is the transmission connection point capacity, both when importing and exporting. This constraint can be formulated directly in terms of the charging and discharging variables of the energy storage device - $P^c(t)$ and $P^d(t)$ respectively:

$$P^c(t) < P_{tcp}^{max} + P_{wind}(t) - P_{dem}(t)\ ;\ \forall t = 1,2, \dots n_t \tag{4.5}$$

$$P^d(t) < P_{tcp}^{max} - P_{wind}(t) + P_{dem}(t)\ ;\ \forall t = 1,2, \dots n_t \tag{4.6}$$

Where P_{tcp}^{max} is the rating of the transmission connection point, $P_{wind}(t)$ is the total wind generation (after curtailment), and $P_{dem}(t)$ is the current demand of the network.

Availability of curtailed energy constraint

The maximum level of charging from otherwise-curtailed wind generation, $P^{cc}(t)$, can be no more than the initial curtailment level. This constraint is defined is as:

$$0 < P^{cc}(t) < P_{curt}(t);\ \forall t = 1,2,\dots,n_t \tag{4.7}$$

where $P_{curt}(t)$ is the power curtailed without the action of energy storage.

Modelling the energy storage device

Constraints are used to model the physical limits of the energy storage device: maximum and minimum states of charge; maximum and minimum rates of charge; and the requirement that the initial and final states of charge are equal:

$$0 < P^{c}(t) < P^{c}_{max};\ \forall t = 1,2,\dots,n_t \tag{4.8}$$

$$0 < P^{d}(t) < \varepsilon_d P^{d}_{max};\ \forall t = 1,2,\dots,n_t \tag{4.9}$$

$$0 < P^{cc}(t) < P^{c}_{max};\ \forall t = 1,2,\dots,n_t \tag{4.10}$$

$$P^{c}(t) + P^{cc}(t) < P^{c}_{max};\ \forall t = 1,2,\dots,n_t \tag{4.11}$$

Inequalities (4.8) – (4.11) ensure that the charging and discharging of the device remains within its power limits, P^{c}_{max} and P^{d}_{max} respectively. Inequality (4.8) and (4.10) ensure that charging from the grid and charging from otherwise-curtailed wind generation do not exceed the device limits, inequality (4.12) ensures that the combination of the two also maintain the limit. Inequality (4.9) limits the discharge; note that this requires the addition of the discharge efficiency, ε_d, that all power variables used in the optimisation are *grid-side* with respect to the energy conversion device (see Figure 12). The value $P^{d}(t)$ is therefore the energy returned to the grid from the energy storage device. The power flow into the energy conversion on the *storage-side* must be bigger than this due to the losses associated with the conversion process. Therefore maintaining the device limits on the *storage-side* of the conversion requires that the *grid-side* power is lower than the device limit by the discharge efficiency.

Finally the state of charge variables must be constrained:

$$0 < SOC_0 + \frac{\Delta t}{E^{cap}} \sum_{t=1}^{n} \left\{ \varepsilon_c \left(P^c(t) + P_{curt}(t)\right) - \frac{P^d(t)}{\varepsilon_d} \right\} < SOC_{max};\ t = 1..n_t \tag{4.12}$$

$$\sum_{t=1}^{n_t} \left\{ \varepsilon_c \left(P^c(t) + P^{cc}(t)\right) + \frac{P^d(t)}{\varepsilon_d} \right\} = 0 \tag{4.13}$$

Inequality (4.12) defines a set of n_t inequalities - one for each time-step. At each time-step the energy storage must be between 0 and the maximum state of charge – SOC_{max}, taken here to be 1. The value of the state of charge during time-step t is a combination of the initial state of charge, SOC_0, and the charging and discharging actions of the store during each preceding time-step t.

Finally equation (4.13) ensures that the initial and final states of charge are equal by making the sum of *storage side* flows into and out of the store equal.

The full formulation of the linear programing optimisation problem is given by (4.5) – (4.13). For ease of reference the equations are listed together with a symbol list in Appendix 1.

4.3.5 Implementing the optimisation

A number of simplifications can be applied to the problem laid out above. The full problem is an optimisation in $3n_t$ unknowns. For large problems, a reduction in the size of the problem leads to significant reductions in the computational resources required. The following observations can be used to reduce the number of variables:

1. **Time-steps with curtailed energy available for charging:** the transmission connection point will be at full export capacity, otherwise curtailment would not occur. There is no capacity to discharge the store and $P^d(t)$ is therefore constrained to 0. These variables can be removed from the problem.
2. **Time-steps with more curtailed energy available than the energy storage can absorb:** if the curtailed energy is larger than the maximum power rating

of the energy store, and the cost of curtailed energy is less than the market price, the optimisation will use curtailed energy in preference than to buying from the market. The value of $P^c(t)$ will therefore be zero and can be removed from the optimisation.

3. **No curtailed energy available**: the value of $P_{curt}(t)$ is constrained to 0 and can be removed from the optimisation.

Observations 1 and 3 reduce the maximum size of the optimisation to $2n_t$ unknowns, and the actual size will be smaller than this by the number of time-steps during which observation 2 is valid.

The optimisation has been coded in Matlab [4.10] using an interior point solver. The maximum size of the problem that can be solved on a standard 32-bit machine is approximately 1000 time-steps. The limit is set by the maximum size of the matrix generated during the optimisation. Using 64-bit Matlab allows up to approximately 8000 time-steps to be solved. With half-hour time-steps this gives a maximum optimisation time-horizon of approximately 5 months. In this study a full 1-year time-series is split into four 3-month sections and each is solved as a separate optimisation. The 3 additional points during the year where energy storage is forced back to its initial value has a minimal effect on the optimal results, as discussed further in Chapter 5.

4.4 Case study

This section provides a case study using historical wind generation and network demand for a representative distribution network from Scotland (UK). The aim of the section is to show the use of the optimisation problem developed, to give a set of results for analysis and to highlight some important issues in the optimisation of active distribution networks.

4.4.1 Case study description

The case study models a typical 33kV distribution network. Demand ranges from 6-30MW. Firm wind farm connections total 41 MW, and four separate scenarios are modelled involving non-firm wind generation:

I. *No non-firm wind generation*. There is no curtailment and energy storage only operates in arbitrage mode

II. *Low non-firm wind penetration*: 10MW non-firm wind capacity

III. *High non-firm wind penetration:* 20MW non-firm wind capacity

IV. *Curtailment-reduction only*: 20MW non-firm wind power capacity connected, but the energy storage is only able to time-shift curtailed generation and arbitrage is not allowed. This is implemented by setting the limit on charging from the grid to 0 for all time-steps.

The network characteristics for all scenarios and the curtailment without energy storage for scenarios II to IV are given in Table 2. The initial energy curtailed, and the number of time-steps where curtailment is applied are calculated using the procedure identified in (4.1.5) – (4.1.7) above. The price that energy storage pays for otherwise curtailed energy from non-firm wind is set to 0. This reflects that negligible marginal cost of production for wind generation, and the fact that if multiple wind generator were competing to sell to the energy storage in an ideal market the prices would be forced to zero.

Table 2: Summary of network for Chapter 4 case study including generation characteristics for scenarios II – IV without energy storage

Demand	6 – 30 MW	
Transmission connection point capacity	35 MW	
Firm wind capacity	41MW	
Price of curtailed energy to store	£0	
Scenario	**Low (II)**	**High (III) and Curtailment only (IV)**
Non- firm capacity (MW)	10	20
Non-firm generation (GWh)	44.9	89.8
Curtailed generation (GWh)	3.38	25.1
Fraction curtailed	0.075	0.28
No. of time-steps with curtailment (out of 17520)	2440	5839

Supply and demand data is taken from a representative UK distribution network, where the time-series consists of half-hourly average demand and generation values for 2009. Figure 15 shows a two-week period of the normalized data and Figure 16 shows a load-duration curve for the distribution network. Demand displays regular daily, weekly and annual variations. High demand periods occur during winter months and early evening, lowest demand occurs during summer nights. By contrast, the wind generation does not display regular variations.

The curtailment applied to non-firm wind generation without energy storage for the same two-week period is illustrated in Figure 17, for the high and low penetration scenarios. With 10MW of non-firm wind generation, only 3.38GWh is curtailed across the year, compared to 250GWh when 20MW is installed. These figures represent 7.5% and 28% of the total available non-firm generation respectively. The high levels of curtailment seen in the 20MW scenario will only be viable if the wind farm has a high uncurtailed capacity factor (> 0.45), and such wind farms will be located in areas of high wind-resource, where distribution networks are likely to be at their most stretched. As well as increasing the fraction of energy curtailed, the increased penetration of non-firm wind generation changes the time structure of curtailment. Figure 14.b shows the fraction of curtailment that occurs between midnight and 6AM as non-firm capacity increases. At low non-firm capacity a high fraction of curtailment is overnight. Such a time-structure can allow the use of pre-defined periods for charging and discharging as suggest in [4.11, 4.12]. As non-firm capacity increases, the fraction of curtailment occuring overnight drops, and this is no longer a viable control strategy. With very high non-firm capacities the fraction of curtailment in this quarter of the day approached 25%, there is no greater curtailment overnight compared to other times of day.

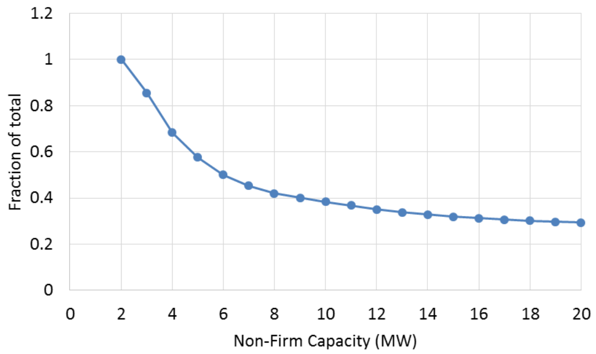

Figure 14: Fraction of curtailment occurring between midnight and 6AM with non-firm wind generation

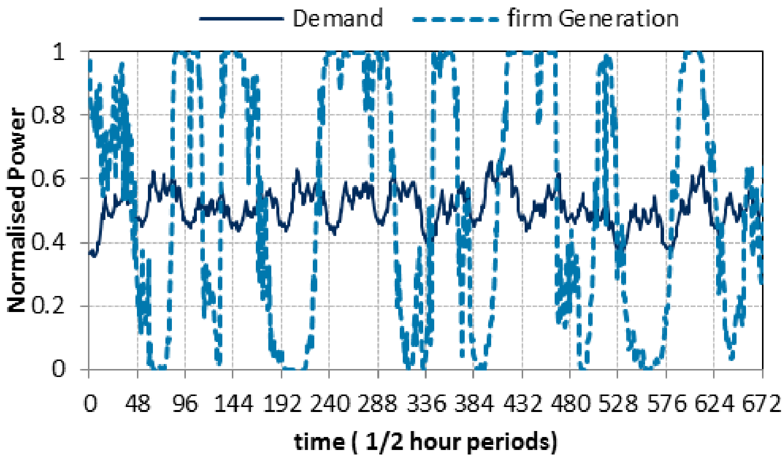

Figure 15: Time-series of normalised demand and generation for two weeks during October 2009.

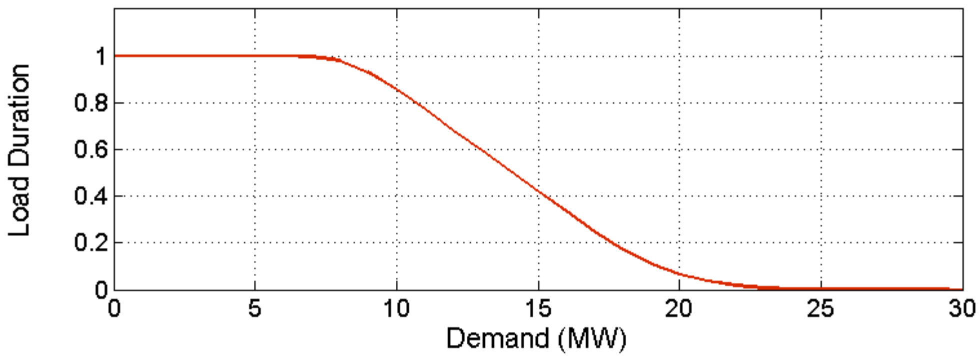

Figure 16: Load duration curve for chapter 4 case study.

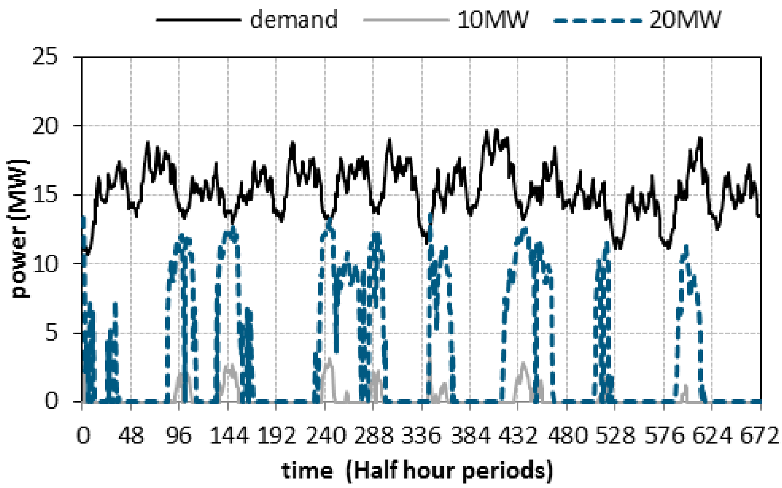

Figure 17: Two weeks data for curtailment of non-firm wind generation without energy storage for scenarios with 10MW and 20MW of non-firm wind capacity, and network demand.

Market prices for electricity are provided by ELEXON, the UK balancing and settlement code company [4.13]. The UK does not operate a 'pool type' electricity system with a true spot market, however market data is provided on transactions through the UK market system via [4.14]. This takes a weighted average of all trades carried out on the open market for a particular settlement-period over the three days leading up to gate closure for the period [4.15]. Prices range from £5.27/MWh to £517.46 /MWh, with an average of £36.89 / MWh - a price duration curve is shown in Figure 18.

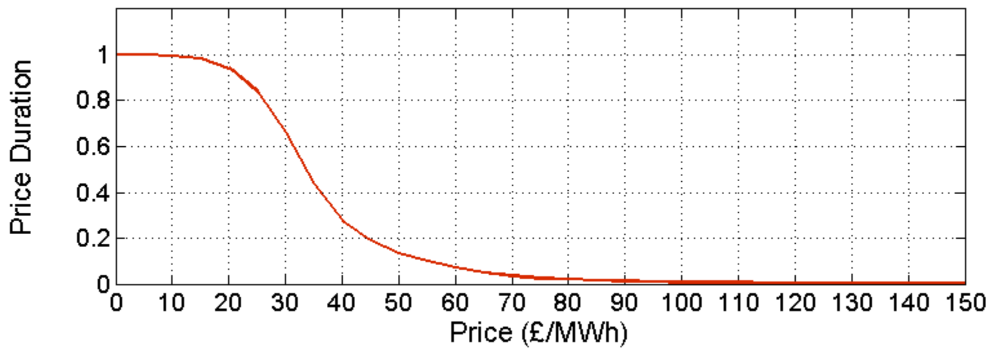

Figure 18: Price duration curve for Chapter 4 case study, taken from UK market price for 2009 [4.12].

Energy storage devices are modelled as 1MW, 6MWh units and the following investigations are conducted:

- *The effect of energy storage efficiency*. Stores with round trip efficiencies ranging from 55% to 95% are modelled.
- *Energy storage charge cycling*. The size and number of energy storage cycles is investigated. Estimates of lifetimes rely on knowledge of the number and depth of discharge of storage cycles. The optimal schedule for a 75% efficient energy store is used to investigate storage cycling.
- *Total energy storage penetration.* The marginal revenue and marginal curtailment reduction curves for the network are constructed in order to show the effect of increasing the total capacity of energy storage. A network is modelled with 77% efficient energy storage devices connected with storage capacity ranging from 1 to 20MW and with the power-to-energy capacity ratio kept at 1MW:6MWh.

The year-long problem is solved using the algorithm described above and by splitting the time-series into three-month segments. This split is required to manage the size of the optimisation problem and the matrices required to solve it. Each 3-month segment is solved separately in approximately 2 hours on the University of Strathclyde Engineering High Performance Computer [4.16], which is a 1000 core

SUN Fire X2270-based machine with Intel Xeon X5570 CPUs. The simulations use a computing node with 8, 2.93GHz cores and 12GB of RAM. The High Performance Computer provides access to a large number of nodes which allows multiple scenarios to be computed, however an individual scenario can be run on a desktop computer.

4.4.2 Case study results summary

The key results from the optimisation are the optimal charging and discharging variables for each time-step. These are combined to give an optimal schedule across the time-horizon for the energy storage device to follow. These values then allow the revenue accruing to the energy storage and the reduction in curtailment to be calculated. Table 3 gives the total revenue and total curtailment reduction for each of the scenarios modelled.

The general conclusions from these results are that increasing efficiency increases revenue but decreases curtailment reduction. Revenues are highest in scenario III with the highest non-firm capacity and therefore the greatest initial curtailment. All scenarios are modelled with a 1MW/6MWh storage device and in addition scenario III is repeated for larger devices to and shows that the marginal revenue and marginal curtailment reduction of each 1MM/6MWh unit reduces as the total storage capacity increases. The results in Table 3 form the basis of the discussion for the remainder of this chapter.

Table 3: Revenue generation and curtailment reduction for all Chapter 4 scenarios.

Scenario	Energy Storage Efficiency (%)	Energy Storage size (MW/MWh)	Total Revenue (£1000)	Total Curtailment reduction (GWh)
I	55%	1/6	15.1	*N/A*
	65%	1/6	23.6	*N/A*
	75%	1/6	33.5	*N/A*
	85%	1/6	44.1	*N/A*
	95%	1/6	55.2	*N/A*
II	55%	1/6	28.6	0.704
	65%	1/6	36.7	0.670
	75%	1/6	46.0	0.641
	85%	1/6	55.8	0.617
	95%	1/6	65.8	0.595
III	55%	1/6	39.6	1.31
	65%	1/6	46.3	1.23
	75%	1/6	53.8	1.17
	85%	1/6	61.5	1.11
	95%	1/6	69.5	1.07
IV	55%	1/6	37.0	1.31
	65%	1/6	40.9	1.23
	75%	1/6	44.5	1.17
	85%	1/6	47.9	1.11
	95%	1/6	51.2	1.07
III	77%	1/6	55.3	1.16
		2/12	1.09	2.25
		3/18	1.59	3.27
		4/24	2.09	4.24
		5/30	2.56	5.17
		6/36	3.02	6.06
		7/42	3.47	6.90
		8/48	3.91	7.69
		9/54	4.33	8.43
		10/60	4.73	9.12
		15/90	6.57	12.0
		16/96	6.91	12.4
		20/120	8.17	14.1
		21/126	8.46	14.4
IV	77%	1/6	45.7	1.16

4.4.3 Optimal operation of a 1MW, 6MWh 77% efficient store

Results for scenario III – the high non-firm wind generation scenario – and with a 1MW, 6MWh, 77% efficient energy storage device are used to give an example of the detail of the outputs from the optimisation model. The round trip efficiency corresponds to the value quoted from sodium sulphur batteries which are currently a developing energy storage technology suitable for energy shifting in distribution networks [4.8], [4.9].

Figure 19 illustrates a 1-week optimal storage schedule; the vertical shaded areas crossing all three graphs highlight time-steps of network congestion that lead to curtailment. During these time-steps the store can only charge, as the transmission network is exporting at full capacity. Outside of these times the energy store charges and discharges with the aim of making the best possible use of the market price variation. This can be seen during day 3: in the second half of the day there is a significant spike in the market price. Just prior to this peak, the energy storage charges at its full rate, then discharges across the price peak, therefore gaining greatest revenue from arbitrage.

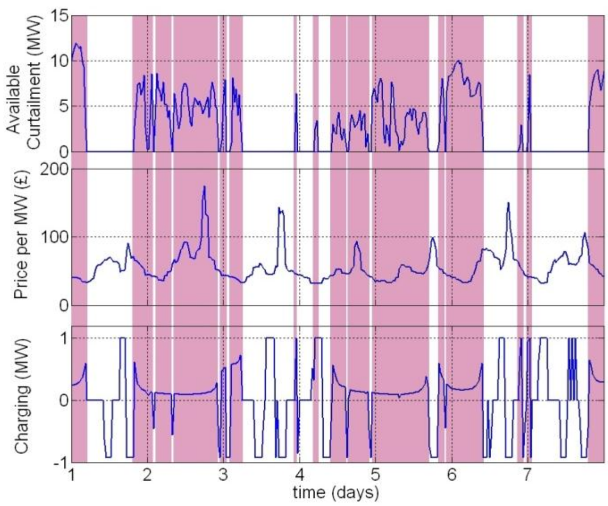

Figure 19: Example results from the single bus network optimisation for a 1MW/6MWh 77% efficient energy store. Results are for a 7-day period with (a) the original wind-farm curtailment, (b) market price and (c) the optimal storage schedule. The shaded sections indicate time-steps with curtailment.

When continual or near-continual curtailment occurs for an extended time interval, there is a *degeneracy* in the mathematical solution. That is, there exists more than one set of control variables which are optimal. The degeneracy occurs because there are more consecutive time-steps with curtailment than the energy storage device needs to fully charge. Charging can occur at the start of the period of curtailment, at the end, or some other permutation. In the case of degeneracy, the algorithm used defines the shape of the optimal solution chosen. In this case the smoothed curved sections in the storage profile visible, for example during day 5, are an artefact of degeneracy and the action of the interior point algorithm. Summary statistics for the optimal solution for this scenario are shown in Table 4.

Table 4: Summary statistics for a 1MW, 6MWh 77% efficient energy storage devices connected under Scenario III – High non-firm wind generation

Energy Storage Device used	1MW, 6MWh, 77% round trip efficiency	
Total curtailment reduction	1,160MWh	
Total energy purchased from grid	1,060MWh	
Total payment to buy from grid		***£26,400***
Average value of energy purchased from grid	£25.9 / MWh	
Total energy discharged	1,710MWh	
Total receipts from discharging		***£81,600***
Average value of energy discharged to grid	£47.70 / MWh	
Total Storage Revenue		***£55,300***

Across the year the energy storage device charges using 2,220MWh and discharges 1,710MWh. The 77% difference represented storage efficiency losses. Of the energy charged 1,160MWh is brought from the grid in arbitrage transactions at an average price of £25.90/MWh, and 1,060MWh is charged from otherwise-curtailed wind generation. Discharge is made at an average price of £47.70 and the total revenue to the energy storage device over the period is £55,300. This figure can, in a market situation, be considered as the benefit created by the energy storage device. Benefit is added in two ways: firstly the store takes low value electricity at times of low price, and for a cost of 77% of energy increases its value by making it available at times of higher price. Secondly, the store takes potential wind energy that has effectively zero value – energy that cannot be used – and gives it value by storing it until such time as it can be used.

If the benefit of wind is measured as the energy generated by installed capacity, the increased benefit of wind capacity can be measured by the additional 1,160MWh of generation. As discussed in Section 4.1, this measure does not take account of losses incurred in making this energy available to the network via the energy store. In this case, 23% of the additional generation is lost and therefore the increased value of wind generation in terms of offsetting import to the network is $1{,}160 \times 0.77 = 893\text{MWh}$.

The reduction in the net cost of import to the network has reduced by the same value as the net revenue generated by the energy storage device. In this case £55,300. This is split between arbitrage and curtailment reduction and it is difficult to separate the contributions from each revenue stream exactly. This is because once stored, energy from both sources are pooled. An estimate can be made by assuming that energy from otherwise curtailed wind generation is on average sold at the average discharge price of £47.70 (see Table 4). Adjusting for energy storage losses, an estimate of the benefit increase of wind generation can be calculated as follows:

$$\Delta Value\ of\ wind = \Delta E_{curt} \times \varepsilon_{rt} \times \overline{\pi_{discharge}} = 1{,}160 \times 0.77 \times 47.70 = \text{£}42{,}600 \tag{4.15}$$

A direct estimate of the increase in benefit from wind generation can be calculated for a situation where arbitrage is not used. This is Scenario IV, and the resultant total energy storage revenue is £45,700.

Why is the increase in benefit from wind generation without arbitrage higher that the estimated value when arbitrage is allowed? The reason is that when arbitrage is allowed, the optimisation schedules energy storage to maximise the *total* revenue, not to maximise the revenue from curtailed wind generation. In scenario III, the energy storage will charge from curtailed generation when available but will discharge quickly – even if the price is relatively low. This ensures that energy storage is available quickly for further transactions. If the store does not discharge the curtailed energy until peak-price the opportunity to carry out arbitrage in the interim is missed.

An important observation regarding the optimal schedules is that energy storage should continue to charge and discharge regularly, rather than storing energy for long periods. For the 77% efficient store in scenario III, there are only 12 occasions throughout the year where the store remains at the same state of charge for 10 hours or more, and the absolute longest is 12 hours. The medium time that the store remains at the same state of charge is 1.75 hours.

In conclusion, the value of the 1MW, 6MWh, 77% efficient storage device in the active network described is estimated at £55,300 per year. It allows the generation of an additional 1,160MWh of wind generation, of which 893MWh is useful. In monetary terms this additional benefit due to wind generation is approximately £42,600 created by raising the value of otherwise curtailed wind generation from effectively 0 to an average of £47.70/MWh. The remaining value from the energy store comes from arbitrage transactions. These results are for a specific case study and the next subsections go on to investigate how this varies in different scenarios.

4.4.4 Investigating energy storage efficiency

The round trip efficiency of a storage device is directly relevant to the benefit that it adds. The lower the efficiency, the greater the energy cost of moving energy between time-steps, and this cost must be redeemed.

Figure 20 shows the storage revenue generated for the four scenarios and how this varies with storage round trip efficiency. Storage makes most revenue in scenario III (high non-firm penetration) with high efficiency and least revenue in scenario I (no non-firm wind generation) and low efficiency. These results are intuitive: scenario III has the greatest quantity of zero price curtailed wind generation that can be used by the store whereas scenario I has no zero price energy. The high efficiency device gains the greatest return for each unit of energy stored, as more is available for discharging to the grid.

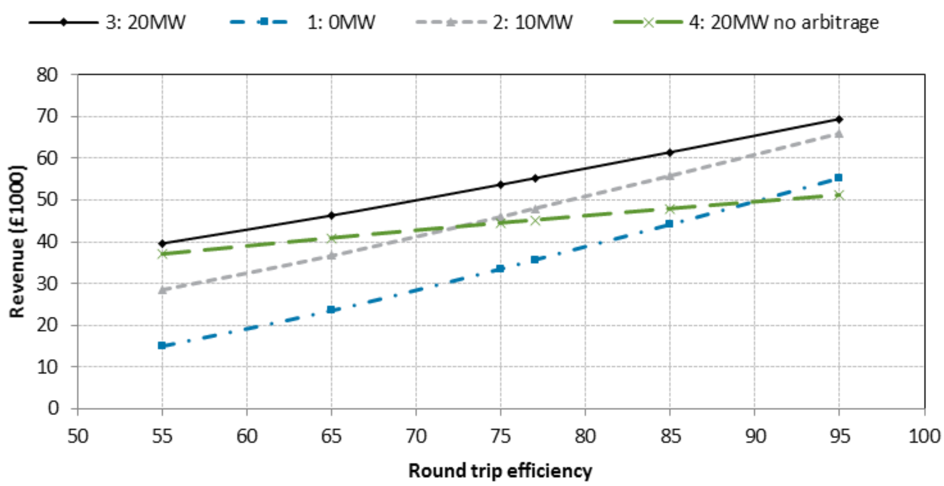

Figure 20: Energy storage revenue generated as a function of round trip efficiency

In all scenarios the revenue increases with efficiency, but the rate of increase varies significantly between scenarios, as shown by the gradient of the lines. Scenario I, with arbitrage only has the highest gradient compared with scenarios involving both arbitrage and curtailment-reduction (scenarios II and III). Scenario IV, which does not allow arbitrage has a much smaller gradient. A linearised measure of the gradients is given in Table 5 and shows that when arbitrage is not allowed, the increase in revenue with efficiency is less than half that when arbitrage is allowed.

The explanation of this result can be found in the mechanism of revenue creation. Increasing efficiency leads to two effects which can increase revenues when engaging in arbitrage: (1) a lower energy cost of using the energy storage, and (2) more numerous opportunities for profitable arbitrage.

The first of these is simply the fact that, if losses are considered as the cost of using energy storage, lower losses mean lower arbitrage costs for a particular transaction. Every transaction made produces more revenue as there is more energy to sell back to the market.

Table 5: Gradient of annual revenue as a function of energy storage efficiency

Scenario	Average gradient: revenue per percentage efficiency increase (£ / %)
Scenario I- arbitrage only, no non-firm wind	933
Scenario II- low non-firm wind penetration	*1,000*
Scenarios IV – high non-firm wind penetration	*747*
Scenario V – curtailment-reduction only, high non-firm wind penetration	*354*

The second effect is due to the requirement that, for a profitable transaction between any two time-steps to exist, the ratio of prices must be greater than the inverse of the round trip efficiency:

$$\frac{\pi(t_2)}{\pi(t_1)} > \frac{1}{\varepsilon_{rt}} \tag{4.16}$$

If the ratio of prices does not meet the condition of inequality (4.16), any arbitrage transaction will require a larger payment to buy power than is received by selling the remainder - and is therefore not profitable. The effect of this is seen by comparing results for scenario I (arbitrage only) for a low and high efficient store over a seven-day period as shown in Figure 21. The first store has a round trip efficiency of 65% and for a particular arbitrage transaction to be profitable the sell-price must be 1.53 times the buy-price. The second store has a round trip efficiency of 95%, and therefore can make profitable transactions where the sell price is only 1.05 times the buy price. This means that more of the variations in the price time-series can be used profitably.

As an example, consider the price time-series between the end of day 2 and the end of day 3 (highlighted in Figure 21). The price begins low in the overnight dip, then rises to a plateau for the majority of the daytime before an evening peak. Taking the daytime plateau to have a value of £63/MW the following ratios can be calculated:

Ratio of maximum price to minimum price: $$\frac{\max(\pi)}{\min(\pi)} = 2.6 \qquad (4.17)$$

Ratio of plateau price to minimum price: $$\frac{\pi_{plateau}}{\min(\pi_{day\,3})} = 1.9 \qquad (4.18)$$

Ratio of maximum price to plateau price: $$\frac{\max(\pi)}{\pi_{plateau}} = 1.4 \qquad (4.19)$$

Equation (4.17) and (4.18) give a result which is large enough that both the 65% and 95% efficient storage price can make profitable transactions. However, the ratio of the maximum price to the plateau price is only 1.4 and is large enough for the 95% efficient store to make a profitable transactions but not the 65% efficient device. In the case of the 65% efficient store the optimal strategy is to charge at the price minimum and discharge at the price maximum. For the 95% efficient device this changes and optimally it makes two charge cycles: charging at minimum price and discharging at the plateau price, then charging again at the plateau price and discharging at maximum price. These strategies are confirmed by the optimal results for the two devices shown in Figure 21.

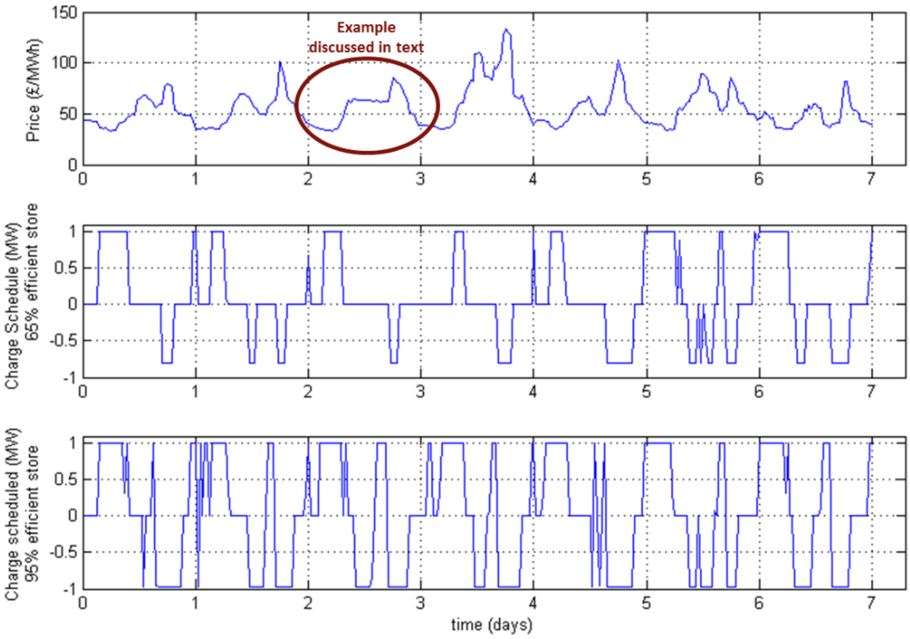

Figure 21: System price and optimised schedules for scenario I (arbitrage only) for energy storage devices with 65% and 95% round trip efficiencies. Note the lower maximum discharge rate of the low efficiency store, and the greater number of arbitrage transactions for the higher efficient device. The circle identifies price data discussed in the text.

The result of these effects is that, for a strategy of operating energy storage that involves arbitrage, high efficiency leads to significantly more value creation by the energy storage device. At this stage, no consideration is given to the lifetime of the storage device, although this is discussed below in Section 4.4.5.

To understand why efficiency is less important when using curtailed energy it is useful to study the affect that efficiency has on curtailment reduction. That is, does storage efficiency effect the quantity of curtailed energy used by the optimal strategy?

Figure 22 shows the reduction in curtailed energy in scenarios II and III (low and high penetrations of non-firm wind generation). The trends show that increasing storage efficiency *lowers* the energy generated by non-firm wind. For scenario II raising the efficiency from 55% to 95% decreases wind generation by 108MWh; for scenario III it decreases wind generation by 240MWh. Measuring the value of wind capacity simply by the raw quantity of energy generated, inefficient storage devices raise the value more than efficient devices. This highlights the inappropriateness of this measure of value.

The curtailment reduction represents the otherwise-curtailed wind energy that is used to charge the store. However, the aim of installing and using energy storage is not to maximise the quantity of energy used to charge, but the quantity of energy discharged. Figure 23 shows the same results, adjusted by the storage efficiency to give the amount of additional wind generation that is *discharged* from the store. Measuring the value of wind generation by its ability to displace import from the transmission network to the network, higher efficiency devices now create more value from wind generation.

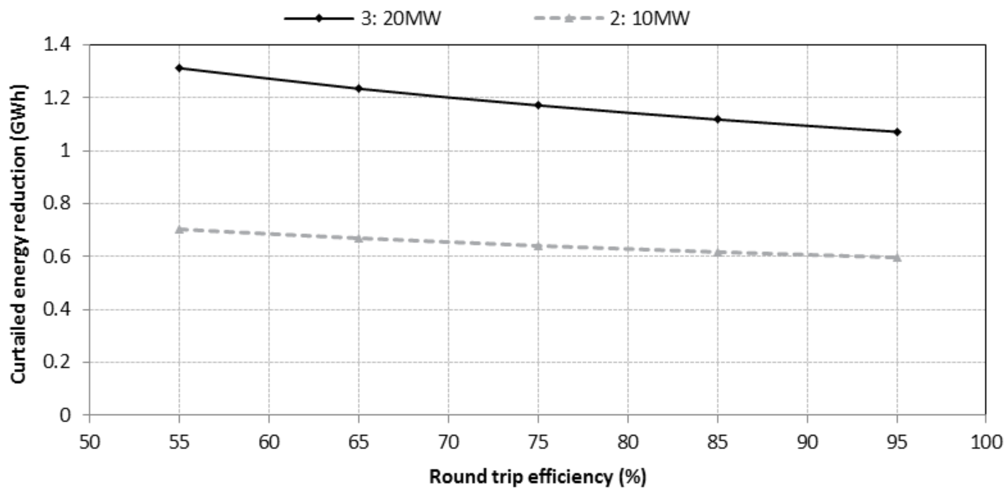

Figure 22: Change in the reduction in curtailed energy with energy storage capacity.

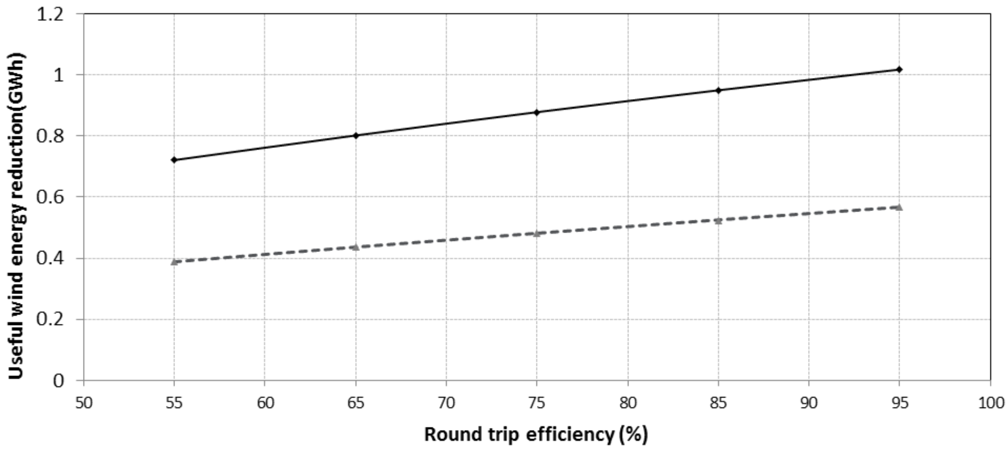

Figure 23: Quantity of otherwise-curtailed wind energy returned to grid after energy storage losses.

The results here act as an example of where it is important to ensure that power system planning and operation takes account of the global objective. In this case the global objective is to minimise import under the assumption that imported energy is mainly from fossil fuel-powered generation. A power system that was optimised to maximise distributed renewable generation or to minimise curtailments would use an inefficient store – the more inefficient the better, as this allows a greater reduction in curtailment. However, it is the energy discharged from a store which directly affects the quantity of energy that must be imported from the transmission network. So the objective of *minimising import from transmission* will choose a highly efficient storage device. In the optimisations used here which consider revenue rather than energy, the effect of losses is implicitly included in the optimisation.

4.4.5 Estimating storage lifetime with optimal schedules

So far the issue of storage lifetime has been ignored. For many storage technologies, devices can only operate for a finite number of charge cycles. In addition, the number of cycles within a lifetime depends on the depth of discharge of the charge cycle, with deeper cycles resulting in a smaller number of lifetime cycles. This is particularly true of chemical batteries, where degradation of the chemicals is an important consideration in lifetime calculations.

Reference [4.7] gives a detailed review of energy storage technologies, including expected lifetimes in years and cycles. Of the technologies discussed, chemical batteries are listed as having a maximum number of charge cycles of less than 10,000. Lead acid has the lowest number of charge cycles, with estimates ranging from 200 cycles upwards.

Table 6: Number of cycles in the lifetime of a sodium sulphur battery at various depths of discharge, taken from [4.19].

Depth of Discharge (%)	Lifetime number of cycles
100	2500
90	4500
50	6500
20	40,000

The effect of depth of discharge on battery lifetime is noted in a number of references. In [4.17] the installation and initial operational plans for a 1MW sodium sulphur battery are discussed. The report notes that reducing the depth of discharge from 100% to 90% can raise the number of lifetime cycles from 2500 to 4000 – 5000, effectively doubling the number of cycles. This is confirmed in [4.18] and [4.19] and the number of cycles at different depths of discharge are shown in Table 6.

A similar pattern is seen with lead acid batteries. In [4.20] the usable capacity of a lead acid battery is shown to drop to 60% of its nominal rating, with varying numbers of charge cycles depending on the depth of discharge. For cycles with 100% depth of discharge, the usable capacity drops to 60% within 200 cycles, for cycles with 50%

depth of discharge 450 cycles can be completed before capacity drop to 60% of nominal, and at cycles of 30% depth of discharge this rises to 1100 cycles.

In many investigations of storage economics, the device is operated on a fixed cycle, for example fully charging and discharging across each 24-hour period. The optimisation discussed here does not apply such a constraint and the resultant schedule is a mixture of full and partial discharge cycles. An estimate of the fraction of lifetime used within a year of optimal operation is more difficult and a method of counting the number of cycles at various depth-of-discharge is required.

Finding the number of cycles of different sizes from a time-series generated from stochastic data requires a cycle-counting algorithm. Rain-flow counting is a method used in structural mechanics to estimate fatigue-damage analysis and provides a method of estimating the number of cycles of particular sizes in a time-series [4.21].

The term *rain-flow* is used to describe the process using an analogy with drops of water falling off a roof, and in this case the 'roof' is a vertically plotted version of the state of charge time-series.

The rain-flow counting method is applied here to the optimal time-series of charging for a storage device to estimate the life of the battery using a set of Matlab files provided in [4.22].

Applying rain-flow counting to the time-series of state-of-charge for a 77% efficient store in scenario III gives the distribution of cycle sizes shown in Figure 24. The result is bi-modal, with the two peaks occurring at the extremes: most cycles are of either less than 10% depth of discharge or greater than 90%.

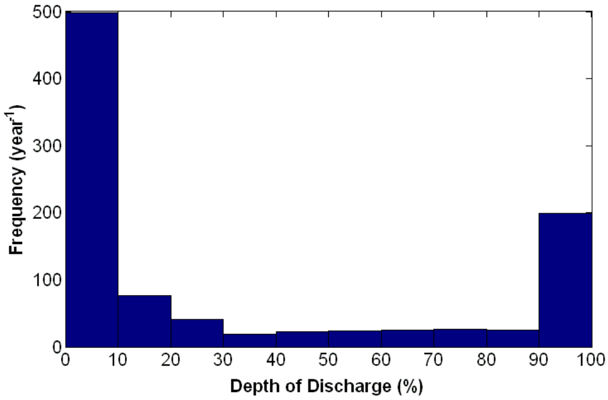

Figure 24: Histogram of the depth of discharge of cycles for the optimal charging strategy for a 77% efficient storage device in Scenario III (High non-firm wind penetration).

The results of the rain-flow counting algorithm and the number of lifetime cycles for a given depth of discharge (Table 6) are combined to estimate the fraction of total lifetime used by the optimal 1-year schedule. Cycles of less than 20% depth of discharge are assumed negligible. Those greater than 20% depth of discharge are rounded up to the next known point in terms of lifetime cycles: 50%, 90% and 100% depth of discharge. So a charge cycle of 30% depth of discharge is assumed to use the same fraction of lifetime as a discharge cycle of 50%; a 70% cycle is rounded up to a 90% cycle etc. The calculation of the fraction of lifetime used is given in Table 7. This method estimates that 11.4% of the life of the battery is used by the optimal schedule over 1 year, assuming that the year is typical this gives a battery life of approximately 9 years.

Table 7: Calculation of an estimate of the battery life used over 1 year for a 77% efficient storage device representing a sodium sulphur battery

Depth of Discharge (%)	Number of cycles in Range	Fraction of lifetime used per cycle	Total lifetime used
< 20	576	0	0
20 – 50	79	$6500^{-1} = 1.54 \times 10^{-4}$	0.012
50 – 90	100	$4500^{-1} = 2.22 \times 10^{-4}$	0.022
90 – 100	199	$2500^{-1} = 4.00 \times 10^{-4}$	0.080
		Total	0.114

4.4.6 The role of energy storage in generating revenue from renewable subsidies

The optimisation of energy storage operation here is based on maximising revenue from the market. In many electricity markets, subsidies for renewable generators form a large fraction of the total revenue of these generators. Where these subsidies are based on the quantity of energy generated, energy storage has the ability to provide value to non-firm wind generation by increasing revenue received from subsidies as well as from the market. In the UK electrical market, wind-generators are able to claim Feed-In-Tariffs (FITs) for installations up to 5MW or Renewables Obligation Certificates (ROCs) for larger wind-farm capacities. The revenue from subsidies is a significant factor in the financial viability of a wind farm. In 2011 the average ROC price was £47.99 / MWh [4.23], which was larger than the spot market average of £41.77 MWh [4.14]. Payments from FITS can be even more: for a 100kW wind turbine the FITs payments are currently £216 / MWh [4.24]. The amounts of subsidy available under FITs for four sizes of wind-farm are included in Table 8.

As discussed earlier in this chapter, the energy losses in a storage device diminish the quantity of additional wind generation that is *useful* in terms of displacing import from the transmission. However, often subsidies are paid based on raw *energy generation*. For existing renewable generation which feeds directly into the grid and is not curtailed, this has the anticipated effect of encouraging the development of renewable generation through the guarantee of enhanced incomes. With the addition of energy storage and curtailment of generators, subsidies paid on this basis have the potential to encourage low efficiency storage over high efficiency storage because low efficiency storage allows greater wind generation (see Figure 22 above). If energy storage devices are located as part of a wind farm, this can be avoided by moving to an *export*-based subsidy in which subsidy payments are based on the energy that flows out through the wind farm meter, after storage losses have been deducted.

Even for export-based subsidies, the problem remains if the energy storage is located outside the wind farm but before any constraint. In this situation, the store is potentially more valuable to the wind farm than located inside the wind farm as subsidies may be paid before storage losses. This is illustrated in Figure 25 ; in (A) decreased efficiency of the store decreases the quantity of energy passing through the export meter but in Figure 25 (B) decreasing efficiency increases the energy passing through the export meter as discussed above in Section 4.4.4.

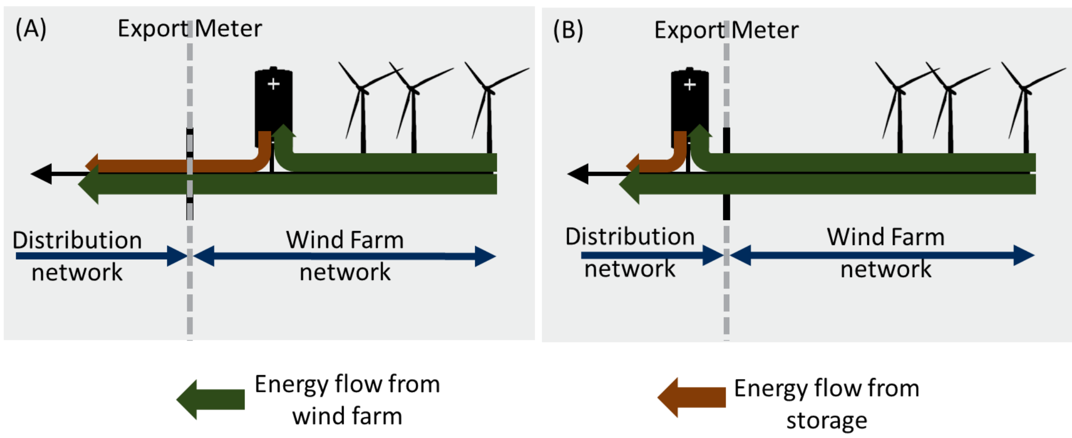

Figure 25: Two scenarios for the location of energy storage relative to a wind farm: (A) within the wind farm and (B) local to the wind farm but connected to the distribution network. Note that in (B) the flow of energy through the export meter is greater due to the location at which storage losses occur.

The effect of both energy storage placement and storage efficiency on subsidy payments can be investigated by calculating the increase in subsidies paid to wind generators under the current UK arrangement. Table 8 shows the subsidy increases for the energy storage results for scenarios III and storage devices with round trip efficiency of 55% and 95%. The results assume that the 20MW of non-firm wind generation is made up of multiple small wind farms each claiming FITS payments at the relevant rate (for row 1, consider 200 separate 100kW wind farms; for row 4 consider four separate 5MW wind farms). Results are calculated assuming that storage is on either the wind farm or network side of the export meter.

Table 8: Total increase in wind farm subsidies created by the use of energy storage based on FITS payment rates to UK wind farms (rates taken from [4.24]).

Wind Farm Size (MW)	Subsidy Rates	***Subsidy payments (£1000)***					
		Generation-based subsidy		Total subsidy (generation + export) With wind farm-side store		Total subsidy (generation + export) With network-side store	
	ESS efficiency:	*55%*	*95%*	*55%*	*95%*	*55%*	*95%*
0.1	FITs: £216 / MWh + £46.4 / MWh export bonus	283	231	317	279	344	281
0.5	FITs: £180 / MWh + £46.4 / MWh export bonus	236	193	270	240	297	243
1.5	FITs: £98/ MWh + £46.4 / MWh export bonus	129	105	162	152	190	155
5.0	FITS: £ 42 / MWh + £46.4 / MWh export bonus	55.1	45.0	88.7	92.4	116	94.9

Table 8 shows that in some circumstances a less efficient store can be more valuable to a wind farm in generating subsidy payments. When located on the network side of the wind farm export meter, the 55% efficient storage leads to a greater increase in subsidy payments compared to the 95% efficient store. If placed within the wind farm, the 55% efficient store leads to greater subsidy payments when generation-based subsidies are high, for example in the case of 100kW, 500kW and 1.5MW wind farms.

When the generation-based payments are high, the difference in subsidy revenue between the 55% and 95% efficient stores is substantial. FITS payments for wind generators up to 100kW, at £216/MWh, are more than four times the average market price of electricity. Energy storage owned or operated by or for the benefit of wind farms will therefore be significantly affected by attempting to maximise subsidies rather than maximising renewable generation (or *useful* wind generation).

This result highlights the need to design subsidies carefully in the light of growing interest in energy storage technologies. Future subsidies for renewable generators operating in conjunction with energy storage must ensure that they are encouraging efficient storage device development over inefficient ones.

4.4.7 Marginal value of energy storage in the case study network

So far the ability of energy storage to generate value has been investigated for single units. A future distribution network is likely to involve multiple installations of energy storage, and the value created by energy storage will depend on the total installed capacities of both energy storage and non-firm wind generation.

The marginal value of energy storage in the current case study can be estimated by running simulations with varying capacities of energy storage. In this study a fixed ratio of power capacity in MW to energy capacity in MWh of 1/6 is maintained to allow ease of comparison between results.

Simulations are run for scenario III (high non-firm penetration) for a storage device with a 77% round trip efficiency and capacities ranging from 1MW/6MWh to 21MW/126MWh. For capacities from 2MW/12MWh upwards the marginal value of the store is estimated as the increase in revenue or wind generation created by the last 1MW/6MW of storage added. The marginal revenue increase and the marginal increase in wind generation are shown in Figure 26. The results show a law of diminishing returns: when storage capacity reaches 21MW/126MWh the marginal revenue has fallen by more than 40% and the marginal curtailment reduction has dropped by more than 60%. The first unit of storage, as with many economic goods or services, is the most valuable. In this scenario the first 1MW/6MWh created a total revenue of £55,200, the 20th 1MW/6MWh unit creates a revenue of £30,400.

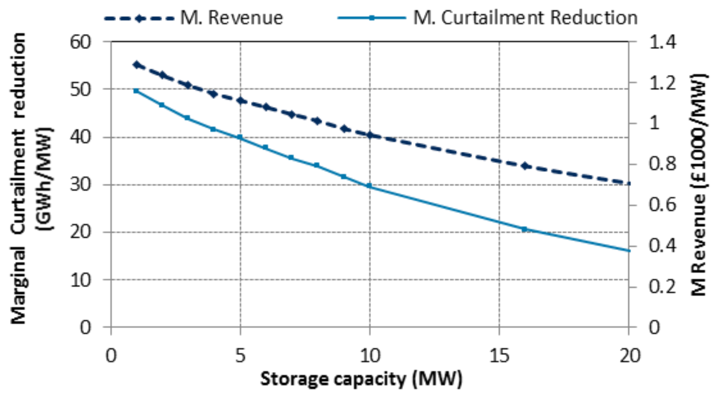

Figure 26: Marginal Revenue and marginal curtailment reduction curves for 75% efficient energy storage in scenario III with 20MW of non-firm wind capacity.

As discussed in Section 4.4.4 this curtailment reduction should be adjusted by the storage efficiency to estimate the quantity of energy import offset by additional wind generation. In this case, the first 1MW/6MWh unit allows for an additional 870MWh to be offset, dropping to 265MWh for the 21st storage unit.

Marginal revenue will fall with total energy storage capacity for two reasons: the limited availability of zero-priced curtailed energy and the finite network capacity. If a large storage capacity is already installed, this uses a significant fraction of the total available curtailed-wind generation; the next unit of storage to be added therefore has a relatively small pool of curtailed energy to use. A similar argument applies to the availability of network capacity: when maximising revenue, all storage units will attempt to charge at low price time-steps and discharge at high price time-steps. With a large capacity of energy storage attempting to charge/discharge the network will become congested at these times and the transmission connection point will reach its capacity importing (when prices are low) and exporting (when prices are high). The next unit of storage will therefore not be able to access the network during the extremes of price and will achieve smaller price uplifts.

4.4.8 Net Present Value of sodium sulphur batteries in the case study

It is of interest to estimate the Net Present Value (NPV) of an energy storage device in this case study. As an example a calculation of the NPV of a sodium sulphur battery is presented here.

A key difficulty in analysing the economics of chemical energy storage is the large variability in cost estimates. Estimates of the capital cost vary widely, particularly for novel storage technologies currently in development and early-trial deployment. Table 9 gives ranges of costs estimates and other characteristics for sodium sulphur batteries and lists the values used in this analysis separately.

Table 9: Characteristics of sodium sulphur battery technologies including ranges that reflect the variety of estimates available, taken from references [4.8], [4.9]

	Na-S (range)	**Estimated used in this study**
Efficiency (%)	0.75 – 0.8	0.77
Total upfront capital cost for 1MW/6MWh (£1,000)	1340 – 2580	1610
Operation and Maintenance (£1,000/yr)	12.9	12.9
Cycles at 100% DoD	2000 – 3200	2500
Estimated life of storage (see Table 7)		9 years
Potential Renewable subsidies	ROCS, FITS	ROCS at £48.34 /MWh

Figures converted to Pounds Sterling at: £1 = US$1.55 [4.25]

The revenue generated by energy storage includes the direct revenue as calculated in the simulations plus any subsidy for which the energy storage itself or the additional renewable generation is eligible. Here subsidies are assumed to be ROCs at the average rate for the period December 2010 – October 2011, which is £48.34 [4.23].

Two discount rates are applied to future cash flows: the UK treasury suggests a value of 3.5% to be used; and a discount rate based on opportunity costs, often estimated at or assumed to be 10% [4.26].

The NPV of a project is given by:

$$NPV = \sum_{i=0}^{N} \frac{R_i - C_i}{(1+r)^i} \tag{4.20}$$

Where N is the number of years in the project, R_i and C_i are the costs and revenues in year i and r is the discount rate. The initial capital investment occurs here in year 0. For a battery with 75% efficiency the lifetime as calculated in Section 4.4.5 is approximately 9 years.

The NPVs for a single sodium sulphur battery connected under scenario I and III are shown in Table 10. All NPV results are negative, meaning that there is a net cost rather than a net benefit to the project. It can be concluded that currently sodium sulphur batteries are not economically viable operating in the scenarios modelled.

Table 10: Net present value of Sodium Sulphur battery energy storage

Non-Firm wind capacity (MW)	Discount Rate (%)	NPV
20	3.5	-£761,000
20	10	-£943,000

If operations and maintenance costs remain fixed, the capital cost of a sodium sulphur battery needs to reduce to £861,000 (from the £1,610,000 assumed in the analysis) to allow an investment to break even under the social-time preference discount rate in scenario III. Using the 10% discount rate the capital cost would need to be £679,000. Both of these capital cost values are well below the lower bounds of the cost estimates currently available.

4.5 Discussion

The distribution network presented here represents a possible future ANM scheme in which curtailment is applied to maintain thermal limits and energy storage is used to mitigate this curtailment and to carry out arbitrage. The results present the baseline level of curtailment which in scenario III reaches 28% of available wind generation. This is significantly higher than in current ANM schemes but it is likely that in the future, high levels of curtailment will be applied and will be economically viable in some areas of high wind resource. Wind resource varies significantly with location and in the UK, the average UK on-shore capacity factor during 2011 was 0.27 [4.27] which represents wind generation which is almost entirely uncurtailed. This capacity factor can be used as an indication of the level at which on-shore wind generation is economically viable. Assuming that wind farms achieving capacity factors of 0.27 or greater are economically viable, an uncurtailed capacity factor of 0.38 when curtailed by 28% will remain economically viable as the curtailed capacity factor will be 0.27. Capacity factors in excess of 0.38 are common in areas with high wind resource. For example on the Shetland Islands, the operator of Burradale Wind Farm reports capacity factors up to 0.52 [4.28]. This suggests that in the windiest areas, curtailment of these levels are likely be economically viable.

Despite the high levels of curtailment and therefore availability of zero-price otherwise-curtailed energy, the net present value of energy storage in the example presented remains significantly below zero. As discussed in Section 4.1, energy storage has the potential to create multiple revenue streams. In this study two revenue streams are exploited: curtailment reduction and arbitrage. Using other revenue streams is likely to increase the benefit of storage. However, in several cases, the benefit of energy storage have no associated revenue stream. For example, in [4.6] the applications with the largest potential benefit is investment deferral. This is of significant value to the network owner, but under existing market rules is unlikely to have an easily accessible revenue stream. For distributed storage, many revenue streams are not available due to minimum size limits. For example on the UK system the minimum unit size for participation in the fast reserve market, something that energy store is likely to be well suited, is 50MW [4.29].

So whilst the NPV of sodium sulphur storage is negative in this case study, if the revenue generated from the two value streams considered here can be combined with revenue from other benefits, storage may become economically viable.

4.5.1 Ownership of energy storage

This case study has not explicitly considered the ownership model of energy storage. A number of options exist: (1) storage is owned and operated by distributed generators themselves; (2) storage is owned and operated by the distribution network operator; and (3) storage is owned by a separate commercial entity and operated independently as a profit maximising asset. Within a market environment options 1 and 3 are likely to lead to operation in a way that maximises revenue; in option 2 the distribution network operator may have the flexibility to consider wider objectives depending on the regulatory regime. The case study of this chapter is relevant to any profit-maximising behaviour, regardless of ownership. However some subtleties should be considered when considering ownership.

If energy storage is owned by a separate commercial entity, it is uncertain at exactly what price wind farms will be prepared to sell otherwise-curtailed generation. If subsidies are ignored it is unlikely that wind generators will be prepared to provide electricity at zero price, although with very low marginal costs and competition between multiple wind farms they are likely to sell at below the external market price. If subsidies are considered, a rational economic actor would be prepared to ask a *negative price* to generate additional electricity from wind generation to allow the collection of subsidies. In an ideal market that negative price would approach the value of the subsidy. Negative bidding is effectively a way of sharing some of the subsidy payment that the wind farm receives with the energy storage provider that facilitated that generation. If the storage is owned directly by the wind generator itself, the assumption of zero price for curtailed wind can be directly applied.

4.5.2 Principles-of-access for energy storage and wind generators

Throughout this case study, the issue of sharing access to a congested distribution network has not been considered. All wind generation has been treated as a single unit, or under joint ownership. This is unlikely to be the case in many distribution networks.

As discussed in Chapter 2, when multiple non-firm generators compete for limited network access a principle-of-access is required to define which generator can access the network. When making a decision on whether to invest in building a wind farm it is important that the principle-of-access is well defined and allows a reliable calculation to be made of the likely levels of curtailment for a particular development.

The addition of energy storage and other flexible technologies has the potential to disrupt this calculation. For example, under LIFO priority system employed on Orkney [4.30] (see Section 1.3 for details) a low priority generator currently assumes that higher priority generators will only be able to generate when wind is available. The introduction of storage allows the high priority generators to time-shift otherwise curtailed generation and export at other times. Low priority generators will see a reduction in their access to the network and possibly greater curtailment than expected. This situation would develop if individual wind farms install their own energy storage units.

The ownership of energy storage by the network operator, such as the scheme proposed on Shetland [4.31] raises a separate problem. In this case, the energy storage, like the distribution lines and transmission connection points become part of the network infrastructure and some method of assigning access to that energy storage device between multiple generators is required.

4.5.3 Flexible demand as a form of energy storage

This chapter has concentrated on energy storage as one example of intertemporal flexibility in ANMS schemes. The other example discussed in this thesis is flexible demand. There are a number of similarities between energy storage and flexible demand which are discussed in detail in Chapter 5. Like energy storage, flexible demand is able to increase the generation from non-firm wind capacity by increasing the power drawn when wind generation is curtailed. It can also reduce the cost of operating the distribution network by drawing less power when prices are low and more power when they are low.

4.6 Maximising the benefit of wind generation

This chapter has used the mathematical objective of maximising revenue generated by storage to investigate the impact of energy storage on an ANM scheme. In the situations modelled, the objective is the same as minimising the net flow of money from distribution network participants to the external market. Taken from the perspective of the whole distribution network, acting as an ANM system, the benefit of the ANM scheme can be equated to the revenue generated by the energy store.

A storage device is not a generator of energy and so its benefit from a system wide perspective comes from its ability to transfer energy generated by other devices from one time-step to another. It is the combination of energy storage and the generator which provides benefit to the system. The combination of wind generation and energy storage provides benefit in terms of reduced costs and reduced carbon. In this way energy storage can be seen as performing a similar role to power lines.

This perspective of energy storage as part of the power-network infrastructure forms an important part of the development of the modelling, and the measurement of the benefit of wind generation used in Chapter 5 and throughout the rest of this thesis.

4.7 Conclusions

This chapter has investigated the role of energy storage in adding benefit to an ANM scheme. A simple energy-balancing, single-bus network model has been used to advance the understanding of energy storage operation in distribution networks with non-firm wind generation.

The benefit created by distributed wind generation and flexible devices within the distribution network is discussed. It is noted that energy storage, as an example of intertemporal network flexibility, is likely to be able to access multiple revenue streams and to derive benefit both from reducing curtailment of wind generation and from other sources such as price-arbitrage.

The single-bus optimisation is run for a range of capacities of non-firm wind generation and energy storage and the following conclusions are reached:

- Energy storage should charge and discharge frequently to maximise the benefit it provides.
- Energy storage has been shown to directly increase the energy generated by non-firm wind farms, and to combine this with the generation of revenue through arbitrage.
- Highly efficient energy storage devices are important in terms of maximising the ability of wind generation to offset import to the distribution network.
- It is important that the objective of network operation is not simply maximising renewable generation, as this would encourage low-efficiency energy storage.
- In addition the payment of renewable subsidies based purely on energy generated has the potential to encourage low-efficiency storage devices over high-efficiency ones, and it is noted that the design of future subsidies may need to consider the role of energy storage.

- For the example of sodium sulphur batteries, a Net Present Value calculation shows that for this case study energy storage is not economically viable, although the role of other revenue streams is discussed.
- Simulations of a range of energy storage penetration show that the value of energy storage obeys a law of diminishing returns, with the marginal value decreasing with the total installed capacity.

The conclusions presented here are revisited in later chapters using the more complex tool of a Dynamic Optimal Power Flow which more accurately models the operation of a distribution network. In particular the role of ownership and principles-of-access are revisited, together with a novel method of measuring the benefit of energy storage in the form of Dynamic Locational Marginal Pricing (Chapter 6).

The simplified model explored in this chapter provides a number of useful general results, however it is not suitable for analysing the specifics of a particular distribution network. As well as the thermal limits and real-power energy balancing developed in this chapter, a more detailed representation of the structure of the network, voltage across the network and reactive power are needed. For this a full AC network model is developed in the next chapter as part of a DOPF based framework.

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Chapter 5: Developing a Dynamic Optimal Power Flow for Active Distribution Networks

THE OPERATION OF POWER SYSTEMS, both at transmission and distribution level, have for a long time been informed by Optimal Power Flow (OPF). Before the last decade, most distribution-level studies concentrated on planning issues, for example the location of reactive power equipment or distributed generation. This focus was due to the lack of active components on distribution networks that were capable of being controlled on short enough timescales to provide real-time management.

More recently the arrival of actively managed distribution networks with the option of curtailing distributed generation has sparked a greater interest in optimising the *operation* of distribution networks. As discussed in Chapter 3, the development of optimisation tools for voltage reactive power and basic wind curtailment have featured significantly in the academic literature. They now form part of Active Network Management (ANM) schemes, for example remote voltage control which has been studied in [5.1] and is now being rolled out for a distributed generation on a radial feeder in North Wales [5.2]. However, the introduction of intertemporal flexibility in the form of energy storage and flexible demand requires both an extension of existing distribution-level tools to cover multiple time-steps and an interdependence between these time-steps. Such tools will be needed for the analysis of second-generation ANM schemes which include intertemporal technologies.

Whilst multi-period, or Dynamic Optimal Power Flow (DOPF) formulations have been discussed in a number of papers over the past two decades, four specific areas of development remain: firstly, the method has not been applied to the specifics of an ANM scheme; secondly, a fully flexible model of storage efficiency has not been developed; thirdly, flexible demand requires greater study particularly in an ANM context; and fourthly the useful economic application of the multipliers that form part of a DOPF solution has not been explored.

This chapter describes a DOPF framework suitable for use with ANM schemes. It brings together existing formulations of various time-independent ANM technologies, with formulations for energy storage and flexible demand. The aim of this chapter is to fill the gaps in existing OPF and DOPF formulations relevant to the modelling of these technologies. Chapter 6 then discusses the economic information in a DOPF solution.

Once the DOPF framework is developed, a simple case study is presented which models a number of second-generation ANM technologies. The case study concentrates on the modelling of intertemporal technologies and their role in managing real and reactive power flows. Results from the case study reinforce the conclusions of Chapter 4 regarding the operation of energy storage and show similar effects through flexible demand.

Whilst the focus of the chapter is on intertemporal technologies and scenarios in which thermal limits are binding, it also discusses the integration of existing time-independent techniques into the framework.

5.1 Active Network Management

The role of ANM in distribution networks is growing, with a number of schemes in the UK using ANM and more in the process of deployment [5.3-5.7]. Current projects and plans are moving beyond the simple model of real-time monitoring and control, to day-ahead scheduling of technologies such as energy storage and flexible demand. This is the hallmark of second-generation ANM discussed in Chapter 2.

The objective of ANM to date has been to maximise the ability of distribution networks to use distributed renewable generation and this is expected to be the driving force behind development of ANM schemes over the coming decade. As discussed in Chapter 4, it is important to consider how the benefit of distributed wind generation and ANM are defined to ensure that the operation of ANM schemes contributes directly to overarching aims, rather than focusing on more local objectives.

Details of the various technologies used in ANM, and those expected to be implemented in second-generation ANM schemes are described in Chapter 2. In this section, a very brief description of the technologies which are included in this mathematical framework of DOPF are given:

- **Generation curtailment**: new wind generation is allowed to connect to distribution networks beyond the firm limit with non-firm connection agreements. Those non-firm generators can be curtailed to keep the network within its limits.
- **Principles-of-access**: the sharing of limited network access between multiple non-firm generators requires a principle-of-access. This defines which non-firm generators have access to limited network capacity at each point in time. A number of principles-of-access are discussed: priority-order principles (of which last-in-first-out is an example); shared-percentage; and technical-best.
- **Energy storage**: energy storage provides a method of time-shifting (potential) energy generation to times where it is most valuable. Energy storage can be scheduled to reduce curtailment or manage network congestion. In addition to the primary role of energy shifting between time-steps, many energy

storage technologies involve power-electronic convertors which can provide reactive power support.

- **Flexible Demand**: a range of demand-side management techniques can be used to provide flexibility as to the timing of demand for electricity. This can be through response to price signals or by direct management of energy delivery to a load. Examples include price-responsive demand on the Olympic peninsula (USA) [5.8] and active management of electric storage heaters on the Shetland Islands (UK) [5.4]. The model used in this thesis involves the delivery of a fixed quantity of energy within an optimisation-horizon, whilst providing flexibility as to the time of delivery.
- **Intertemporal ANM management and objectives:** as with OPF studies, the objectives of DOPF problems should be linked to the overall objectives of the system. In this thesis, maximising the benefit of wind generation in terms of its ability to offset the import to a distribution network (or other local conventional generation) is treated as the objective. Objectives which attempt to minimise import, or minimize the cost of import are discussed. The issues identified in Chapter 4 with the objective of simply maximising the quantity of energy generated from wind capacity are further discussed.
- **Co-ordinated voltage control:** in distribution networks where the management of voltage levels is important, distribution transformer setting can be manipulated to meet network-wide voltage profiles rather than targeting only the local voltage level. In addition, distributed generation can provide flexible reactive power generation (and in future, energy storage may also contribute). The co-ordination of these techniques has already been laid out in the literature on optimisation of ANM schemes [5.1, 5.9].

5.2 The Dynamic Optimal Power Flow concept

To solve a static OPF problem, a mathematical model is built which represents the power system at a particular point in time. Figure 27 shows a network representation of the mathematical model for a simple 3-bus power system. Demand for power from loads is fixed, and in this case generation from the wind turbine is also fixed. The real and reactive power injected to node 2 are control variables which are adjusted to ensure real and reactive power balance across the network and to minimise some objective function.

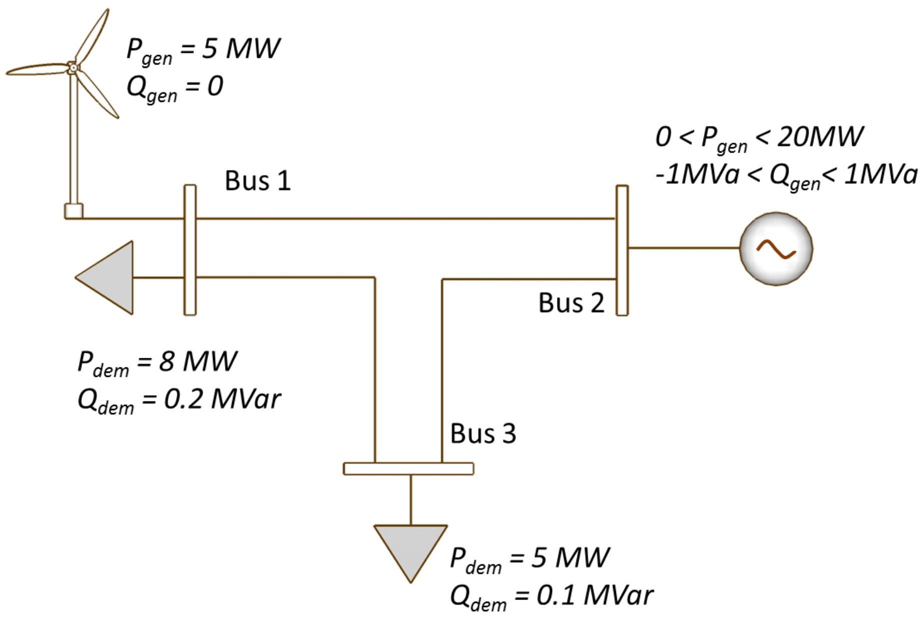

Figure 27 A 3-bus network to illustrate the concept of Optimal Power Flow

The DOPF problem involves extending this mathematical model to include copies of the network at multiple time-steps and linking those time-steps with intertemporal variables to allow modelling of intertemporal technologies such as energy storage and flexible demand. The model illustrated in Figure 27 is extended to the multi-period network of Figure 28. This illustrates the following features of the DOPF mathematical network:

- The physical network is represented separately at each time-step. Each bus is represented by a separate node at each time-step and each power system circuit (overhead line, cable or transformer) is represented by a separate branch at each time-step.

- Different characteristics for buses and circuits can be modelled for different time-steps: for example a node representing a bus at a particular time-step will have associated with it the demand relevant to that time-step.
- Intertemporal technologies are modelled as branches linking nodes that represent the same bus at different time-steps.

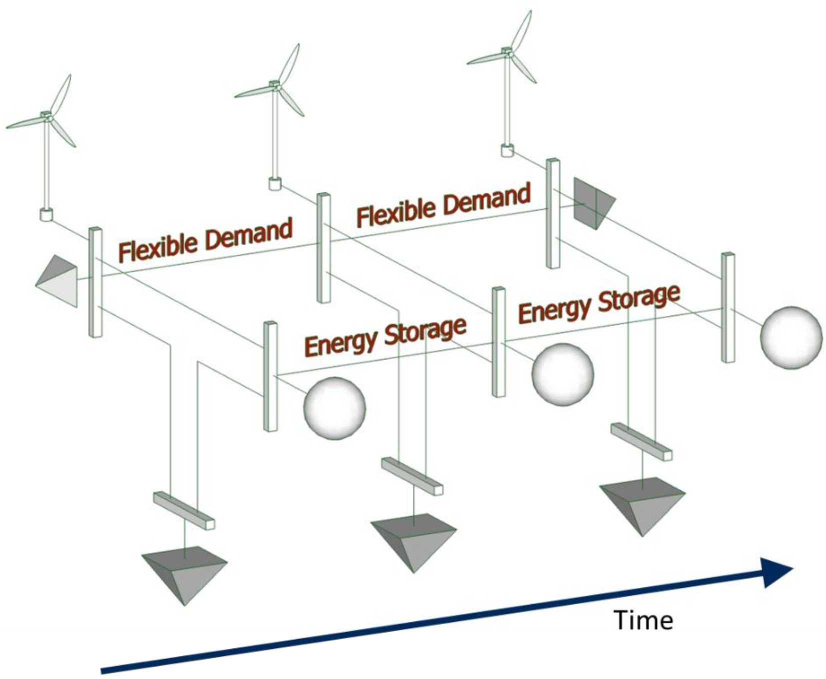

Figure 28: Extension of a 3 bus optimal power flow network to a 9-node DOPF network. In this example there are 3 time-steps, each bus is represented by a separate node at each time-step, and each power-system circuit is represented by a separate branch at each time-step. In addition, intertemporal technologies are represented by branches joining nodes between time-steps.

When discussing DOPF modelling it is important to use terminology to clearly differentiate between power systems components, and mathematical components used to model the power system. In power-flow (and optimal power flow analysis) *buses* and *circuits* are modelled by mathematical *nodes* and *branches*. Nodes and branches are abstract mathematical entities used to *represent* physical power system components. In single time-step OPF it is often possible to use the mathematical and power systems' terms interchangeably, but in DOPF, where multiple nodes are used to represent the same bus at different time-steps, it is crucial that mathematical and power system concepts are each used only when appropriate. Similar attention should be paid to distinguishing between *branches* and *circuit*: multiple branches are used to represent the same circuit during at different time-steps. In addition the mathematical *branch* concept is used to represent intertemporal devices.

A second remark about the network shown in Figure 28 is that it suggests DOPF can be thought of as adding a dimension to the OPF problem. In terms of the physical power system this is a useful way to look at the problem: OPF optimises a two-dimensional power system; DOPF optimises a three-dimensional system (as it has the additional dimension of time). Whilst this is a useful visualisation of the physical system, it should not be carried over to the mathematical network. The reader is encouraged to think of the mathematical model of Figure 28 simply as a bigger network than that of Figure 27. Even when interpreting the network and the results in terms of physical components and the space and time within which the physical power system sits, the mathematical notion should be remembered.

This last point suggests the interpretation of power system circuits, energy storage and flexible demand as members of a large class of *energy vectors.* All three are devices which provide pathways in which energy can flow between nodes in the network. This interpretation suggests that intertemporal flexibility can be thought of as part of the network, rather than as devices connected to the network. If the role of transmission and distribution networks is to transfer power between locations in order to facilitate the efficient supply and demand of energy, why should it not perform the same task in the time dimension?

5.2.1 Mathematical formulation

Table 11 summarises the general terms and some of the structure of OPF and DOPF problems. In OPF a set of *control variables* are adjusted by the optimisation process, *fixed parameters* define limits and parts of the system that cannot be adjusted, and *derived variables* are functions of control variables and fixed parameters.

DOPF discretises the time-horizon up into t_n time-steps and extends all OPF variables and some parameters into time-series. The network must obey the typical OPF constraints such as power flow equations independently during each time-step. Furthermore, additional intertemporal variables and constraints are created. An example of an intertemporal variable is the state of charge of energy storage; that is the fraction of total energy capacity currently in use. The state of charge depends on charge and discharge values in multiple time-steps. The DOPF objective is a function across all time-steps.

5.3 Dynamic Optimal Power Flow for Active Network Management

The development of a DOPF structure for ANM problems is based on a formulation of OPF suitable for use with distribution networks, and concentrates on the combination of firm and non-firm distributed wind generation, energy storage and flexible demand. The inclusion of other ANM technologies, here called time-independent, are discussed in Section 5.4.3.

The basic scenario of both the DOPF problem developed here and the case study system discussed in the remainder of the thesis are as follows:

- A distribution network containing both firm and non-firm wind generation. The network connects to the transmission network via Grid Connection Points;
- Energy storage is connected to specified buses;

Table 11: General structure of mathematical formulation for OPF and DOFP problems

	Standard OPF Formulation	OPF example	Dynamic OPF Formulation	DOPF example
Control variables	$\boldsymbol{x}$	Power generated	$\boldsymbol{x}(t)$	Power generated at generator bus varies with time
Fixed variables	$\boldsymbol{y}$	Voltage magnitude at voltage-controlled bus	$\boldsymbol{y}(t)$	Voltage magnitude at voltage-controlled bus varying with time
Derived variables	$\boldsymbol{z}$	Voltage angles	$\boldsymbol{z}(t)$	Voltage angles varying with time
Intertemporal variables	N/A	N/A	$\boldsymbol{\tau}(t)$	State of charge (SOC) of energy storage device
Objective function	$\min \boldsymbol{f}(\boldsymbol{x},\boldsymbol{y},\boldsymbol{z})$	Minimise cost of operation	$\min f(\boldsymbol{x}(t),\boldsymbol{y}(t),\boldsymbol{z}(t),\boldsymbol{\tau}(t))$	Minimise overall cost across all time-steps
Single time-step equality constraints	$\boldsymbol{g}(\boldsymbol{x},\boldsymbol{y},\boldsymbol{z}) = \boldsymbol{0}$	Power flow equations	$\boldsymbol{g}(\boldsymbol{x}(t),\boldsymbol{y}(t),\boldsymbol{z}(t),\boldsymbol{\tau}(t)) = \boldsymbol{0}\ \forall t$	Power flow equations applied separately at each time-step
Single time-step inequality constraints	$\boldsymbol{h}(\boldsymbol{x},\boldsymbol{y},\boldsymbol{z}) \leq \boldsymbol{0}$	Max / Min limits on Generator outputs and bus voltages	$\boldsymbol{h}(\boldsymbol{x}(t),\boldsymbol{y}(t),\boldsymbol{z}(t),\boldsymbol{\tau}(t)) \leq \boldsymbol{0}\ \forall t$	Max / Min limits on generator outputs and bus voltages. Max / Min values likely to be the same during all time-steps
Intertemporal equality constraints	N/A	N/A	$\boldsymbol{k}(\boldsymbol{x}(t),\boldsymbol{y}(t),\boldsymbol{z}(t),\boldsymbol{\tau}(t)) = \boldsymbol{0}\ \forall t$	The total energy delivered to a load over the optimisation horizon should equal its energy requirement
Intertemporal inequality constraints	N/A	N/A	$\boldsymbol{l}(\boldsymbol{x}(t),\boldsymbol{y}(t),\boldsymbol{z}(t),\boldsymbol{\tau}(t)) \leq \boldsymbol{0}\ \forall t$	Max /Min limits on the SOC of an energy storage device or ramp rates on generators.

- Flexible demand is connected to specified buses;
- Several objectives related to renewable energy are modelled

5.3.1 Objectives

The objectives of the ANM scheme need to be expressed as suitable mathematical formulations. The objective should be based on the role of network management in maximising the value of distributed non-firm wind generation. This is discussed in Section 4.2 and three possible definitions are given: maximising distributed wind generation; minimising the import of energy from the transmission network; and minimising the *cost* of import. The latter two of those definitions are presented here as objectives for the DOPF.

5.3.1.1 Minimise distribution network imports / maximise exports

The formation of an objective that minimised net imports is:

$$f_1(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \min_{\boldsymbol{x}} \sum_{t=1}^{t_n} \left\{ \sum_{gcp=1}^{gcp_n} P_{gcp}(t) \right\} \tag{5.1}$$

Where P_{gcp} is the power imported from grid connection point, gcp, and there are gcp_n grid connection points in total and $\boldsymbol{x}$ is the vector of control variables.

This objective minimises the power imported from all grid connection points, P_{gcp}, and all time-steps. As discussed in Chapter 4, this objective is based on the effect of wind generation on reducing import and ensures that the effect of efficiency losses in the power-network and intertemporal components is fully accounted for.

5.3.1.2 Minimise cost of import / maximise revenue from export:

$$f_2(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \min_{\boldsymbol{x}} \sum_{t=1}^{t_n} \left\{ \pi(t) \sum_{gcp=1}^{gcp_n} P_{gcp}(t) \right\} \tag{5.2}$$

This objective uses exogenous electricity market prices and relies on the assumption that the load and generation on the distribution network are small relative to the overall size of the electricity market; they therefore do not affect market prices.

5.3.2 Single time-step Optimal Power Flow formulation

Distribution network problems require a full AC-formulation of the power flow equations. The formulation of the single time-step OPF applied at each time-step as part of the DOPF is as follows:

- The power balance equations:

$$\boldsymbol{g}(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \boldsymbol{0} \; ; \; \forall \, t \tag{5.3}$$

These include constraints on nodal power balance and the power flow equations. In addition constraints are applied to manage:

- Voltage levels at each bus, b:

$$V_{min}(b) < V(b,t) < V_{max}(b) \; ; \; \forall \, b, t \tag{5.4}$$

where it is assumed that the maximum and minimum voltage limits remain fixed across the optimisation horizon.

- Thermal line limits for lines l:

$$-S_{max}(l) < S(l,t) < S_{max}(l) \; ; \forall \, l, t \tag{5.5}$$

as with voltage limits it is assumed that line ratings are fixed across the optimisation horizon. There are some projects involving dynamic line ratings where this will not hold. In the case of such ratings, the rating will be set separately for each time-step as in [5.10].

- Each grid connection point, gcp, is modelled as a generator with the ability to supply positive and negative values of real and reactive power:

$$P_{gcp}^{min} < P_{gcp}(t) < P_{gcp}^{max} \; ; \forall\, gcp, t \quad (5.6)$$

$$Q_{gcp}^{min} < Q_{gcp}(t) < Q_{gcp}^{max} \; ; \forall\, gcp, t \quad (5.7)$$

Buses connected to a gcp operate as PV buses and the primary gcp (assuming the system is not islanded) bus will act as the reference bus.

The primary transformers are not considered in this analysis, instead the network is modelled at the base voltage of the distribution network, with the thermal capacity of the primary transformer created via the constraint on the circuit between the gcp and the rest of the network (this follows the methods of [5.11, 5.12] among others). The action of on-load-tap-changing transformers applied to distribution network optimisation is well documented, for example in [5.10, 5.11] and these methods can easily be incorporated into DOPF.

5.3.3 Firm distributed generation

Firm generation is considered as 'must-take' and is treated as negative fixed demand; the available generation from a firm generator is then subtracted from the fixed bus demand. It is assumed in this study that firm generators operate at fixed power factor and reactive power is also subtracted from bus demand.

5.3.4 Non-firm distributed generation

Non-firm generation has a maximum output within each time-step, the value of $P_g^{max}(nf,t)$ for each time-step is defined by the available wind resource:

$$0 < P_g(nf,t) < P_g^{max}(nf,t) \; ; \forall\, nf, t \quad (5.8)$$

The power output of non-firm generators is a control variable and can be scheduled anywhere within its range.

5.3.5 Principles-of-Access for non-firm generation

Including the principle-of-access for non-firm generators in a DOPF for ANM is an important advance of this thesis. Three principles-of-access are discussed here: priority order, shared percentage and technical best.

5.3.5.1 Priority order (e.g. LIFO)

For the DOPF to apply a priority order, there must be a distinction in the value of generation from different generators. This is accomplished by modifying the objective function. The modification must be small enough to ensure that it does not interfere with the overall objective of the DOPF, but larger than the tolerance of the optimisation algorithm.

The modified objective has the general form:

$$f_{\text{modified}} = f_{\text{obj}} + \delta_{\text{priority}} \tag{5.9}$$

where f_{obj}, the original objective, as defined by (5.1) and (5.2) and δ_{priority} is the modification. The magnitude of δ_{priority} must be such that both:

$$|f_{\text{obj}}| \gg |\delta_{\text{priority}}| \tag{5.10}$$

$$|f_{tol}| < |\delta_{\text{priority}}| \tag{5.11}$$

where $|f_{\text{obj}}|$ is the magnitude of the original objective and $|f_{tol}|$ is the tolerance chosen for convergence. To achieve this δ_{priority} is defined as:

$$\delta_{\text{priority}} = \sum_{t=1}^{t_n} \left\{ \sum_{nf=1}^{n_{nf}} \frac{p}{k} P_g(nf, t) \right\} \tag{5.12}$$

where p is the priority number, an integer between 1 and n_{nf} with high numbers representing low-priority generators. To ensure that the condition of (5.10) is met, the value of the constant k is chosen so that $k^{-1} \ll 1$ and $^{p}/_{k} < 1$ for the lowest priority generator (highest p). Adding this modification to objective $\boldsymbol{f_1}$ in (5.1) gives:

$$f_1(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \min_{x} \sum_{t=1}^{t_n} \left\{ \sum_{gcp=1}^{gcp_n} \left(P_{gcp}(t)\right) + \sum_{nf=1}^{nf_n} \frac{p}{k} P_g(nf, t) \right\} \quad (5.13)$$

The original objective has now been adjusted so that generation from high-priority generators have more value than that from low-priority generators in minimising the objective.

When applying the modification δ_{priority} to objective 2 in (5.2) k should be set so that $^{p}/_{k} < \min(\boldsymbol{\pi}(t))$ for the lowest-priority generator to maintain the conditions of (5.10) and (5.11).

5.3.5.2 Shared percentage

A shared percentage scheme is one in which all generators receive the same fraction of net overall curtailment. This can be achieved in two ways: either by curtailing all generators by the same fraction of their current output at each time-step, or by ensuring that curtailment, as a fraction of available generation is the same for all generators across the optimisation horizon.

Both of these can be modelled by using additional constraints and the original objective function.

To share the curtailment equally at every time-step, the following constraints should be applied to each time-step:

$$\frac{P_g(nf_1, t)}{P_g^{max}(n_1, t)} = \frac{P_g(nf_i, t)}{P_g^{max}(nf_i, t)} \; \forall\, i = 2,3, .. n_{nf} \, ; \forall\, t = 1,2, \dots n_t \quad (5.14)$$

Equation (5.14) defines (n_{nf} *-1)* constraints for each time-step, linking the fraction of curtailment at each generator to that of an arbitrary reference generator, in this case generator nf_1.

To share the curtailment equally across the entire optimisation-horizon, but allow variations in the curtailment at specific time-steps, the system of equations given by (5.14) are modified by summing across the optimisation-horizon:

$$\sum_{t=1}^{t_n} \frac{P_g(nf_{1,}t)}{P_g^{max}(nf_1, t)} = \sum_{t=1}^{t_n} \frac{P_g(nf_i, t)}{P_g^{max}(nf_{i,}t)} \; ; \; \forall \; i = 1,2, \dots n_t \qquad (5.15)$$

This form of shared percentage (sharing curtailment equally across the entire optimisation-horizon) allows the optimisation flexibility regarding which generator is curtailed during which time-steps, whilst constraining overall curtailments. It is likely to be more useful in planning studies over time-horizons of months, rather than in day-ahead scheduling.

5.3.5.3 Technical best

Technical best principle-of-access means dispatching the generator that best helps the network meet its objective. As the objective is formulated as the objective function, no additional constraints nor alteration of the objective function are added and the optimisation chooses which generators to curtail.

5.3.6 Energy storage

The model of energy storage developed in Chapter 4 can be adapted for use in DOPF formulations. The existing literature on energy storage in optimal power flow does not provide a fully flexible model of storage in terms of efficiencies and scheduling. In [5.13] the model is described as requiring equal charging and discharging efficiencies, although it can be concluded in the cases described in the study must be loss-less. In [5.14] predefined charge and discharge time-steps are defined as inputs to the DOPF.

The key issue that both approaches attempt to solve is that allowing separate charging and discharging variables in the same time-step opens the possibility of both being scheduled together. This is not physically realisable.

Another method of ensuring that charging and discharging do not happen simultaneously is to introduce binary variables to constrain (at most) one of the charging and discharging generators as 'off' during each time-step. However this requires moving to binary or integer programming which is significantly more computationally expensive.

It is shown here that if the round-trip efficiency is less than one, and all generation incurs a positive cost, an optimal solution will have at most one of the two variables (charge and discharge) set at zero.

As DOPF is a network-based optimisation, positive and negative injections to the power network by energy storage need to be adjusted by the charging and discharging efficiencies to effect the state of charge of the store:

$$\Delta SOC = -\frac{\Delta t}{E_{store}^{cap}} \begin{cases} \varepsilon_c P_{store} & if\ P_{store} \geq 0 \\ \dfrac{1}{\varepsilon_d} P_{store} & otherwise \end{cases} \tag{5.16}$$

The relationship between the (network-side) power injections at each time-step and the state of charge of the store has a discontinuity in its gradient at $P_{store} = 0$. This discontinuity is the reason a single charge / discharge power variable cannot be used in the non-linear programming as discussed in Chapter 2.

Instead a 'two-generator' model of energy storage is developed in this thesis, in which generators are used to model the power conversion of a storage device. One generator discharges the store and has a range of operation from 0 to $\varepsilon_d P_{store}^{max}$; the other generator charges the store and has a range of operation from $-P_{store}^{max}$ to 0, which is negative generation. The maximum discharge is adjusted by the discharge efficiency so that the power flow on the storage side of the power convertor does not exceed P_{store}^{max}. This model is illustrated in Figure 29.

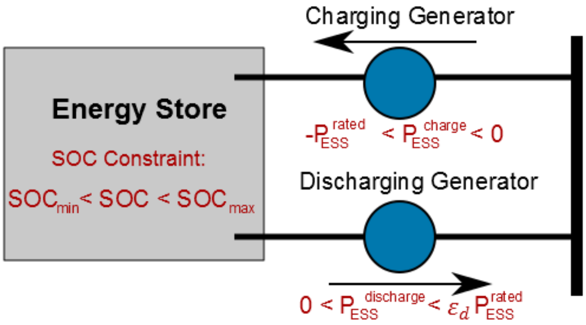

Figure 29: A two-generator model of energy storage for use in DOPF

The power injection from the store to the network can now be written as

$$P_{store} \;=\; P_{store}^{d} + P_{store}^{c} \tag{5.17}$$

where P_{store}^{d} is the discharging generator and P_{store}^{c} is the charging generator and the limits on the action of the two generators during each time-step are:

$$\left.\begin{array}{l} -P_{store}^{max}(t) < P_{store}^{c}(t) < 0 \\ 0 < P_{store}^{d}(t) < \varepsilon_d P_{store}^{max}(t) \end{array}\right\} \forall t \tag{5.18}$$

The state of charge is now related to the injections of two generators and for each time-step it is defined by:

$$SOC_{store}(t) = SOC_{store}(0) - \frac{\varepsilon_c \Delta t}{E_{store}^{cap}} \sum_{t'=1}^{t} P_{store}^{c}(t') - \frac{\Delta t}{E_{store}^{cap} \varepsilon_d} \sum_{t'=1}^{t} P_{store}^{d}(t') \tag{5.19}$$

where $SOC_{store}(0)$ is the initial state of charge. The state of charge is constrained to remain within limits:

$$SOC_{store}^{min} < SOC_{store}(t) < SOC_{store}^{max} \; ; \; \forall \, t \tag{5.20}$$

These limits will usually be 0 and 1, however it is likely that some operational strategies will wish to avoid charging and discharging an energy store to its theoretical limits. In general it is expected that the initial and final state of charge are the same over the optimisation horizon (although this can be varied). Thus:

$$SOC_{store}(0) = SOC_{store}(t_n) \tag{5.21}$$

(5.19) – (5.21) fulfil the same role as equations (4.12) and (4.13) in the simple optimisation of Chapter 4.

In this formulation there is no constraint to stop charging and discharging generators operating during the same time-step – that is for both $P_{store}^{c}(t)$ and $P_{store}^{d}(t)$ to be non-zero. Whilst this solution is feasible mathematically, in operational scenarios it is *non-optimal* and therefore will be avoided in the solution of the DOPF. For this to be the case two conditions must be met: (i) the round-trip efficiency of the energy storage must be less than 1 and (ii) the 'cost' of all generation in the objective is positive.

To demonstrate this proposition, consider a particular time-step within the optimisation. For this time-step there is an optimal change in state of charge, ΔSOC, relating to a charge or discharge of the store. In the mathematical formulation this can be achieved by any combination of charging and discharging which fulfils the equation:

$$\Delta SOC(t) = \frac{-\Delta t}{E_{store}^{cap}} \left\{ \varepsilon_c P_{store}^{c}(t) + \frac{P_{store}^{d}(t)}{\varepsilon_d} \right\} \tag{5.22}$$

Any power used to charge the store, P_{store}^{c}, must be generated elsewhere, either by generation directly connected to the network or imported via a grid connection point. If the cost of generating power is always positive in the objective function, minimising the objective involves minimising the value of $|P_{store}^{c}|$ for the optimal ΔSOC. If $\varepsilon_{rt} <$

1 this minimum occurs when $P_{store}^{c}(t) = 0$ if ΔSOC>0 or when $P_{store}^{d}(t) = 0$ if ΔSOC<0. Thus, with a positive cost of generation and energy storage efficiency less than 1, an optimal solution will only operate at most one of the two charging/discharging generators during each time-step.

Finally, in addition to the real power constraints described in (5.18), energy storage has the potential to provide reactive power support [5.15]. The combination of real and reactive power from an energy storage device is limited by the apparent power according to:

$$S_{store}(t) < S_{store}^{rated}(t) \tag{5.23}$$

where:

$$S_{store}(t) = \sqrt{{P_{store}}^2 + {Q_{store}}^2} \tag{5.24}$$

5.3.7 Flexible demand

The ability to choose when to deliver energy to a demand provides a degree of flexibility to a power system. Demand can be aligned with the availability of wind generation or with times of low market price. There are a range of paradigms for flexible demand: price-responsive demand, directly-managed flexible demand, and interruptible demand to name three. In most cases, the total demand for energy is fixed across a particular time-horizon, and flexibility is provided in terms of the *timing* of that demand.

Flexible demand can therefore add value to non-firm wind capacity through being scheduled during time-steps when wind would otherwise be curtailed, reducing the overall quantity of energy imported to the network. In addition, remaining demand can be scheduled during time-steps of low market price, reducing the overall *cost* of import from the network.

It is proposed here that flexible demand can be thought of as a form of energy storage. Flexible demand, with this understanding, consists of three components: an electricity delivery component; a storage component; and an underlying demand profile. This is shown in Figure 30 with three examples. The storage component allows the storage of the end product of the demand for electricity. This end product can be another form of energy, such as heat storage, a manufactured good such as cast iron, or some other 'embodiment' of energy usage - such as clean clothes. As with electrical energy storage[3] the storage capacity buffers the electrical demand in a washing machine from the underlying consumer demand profile.

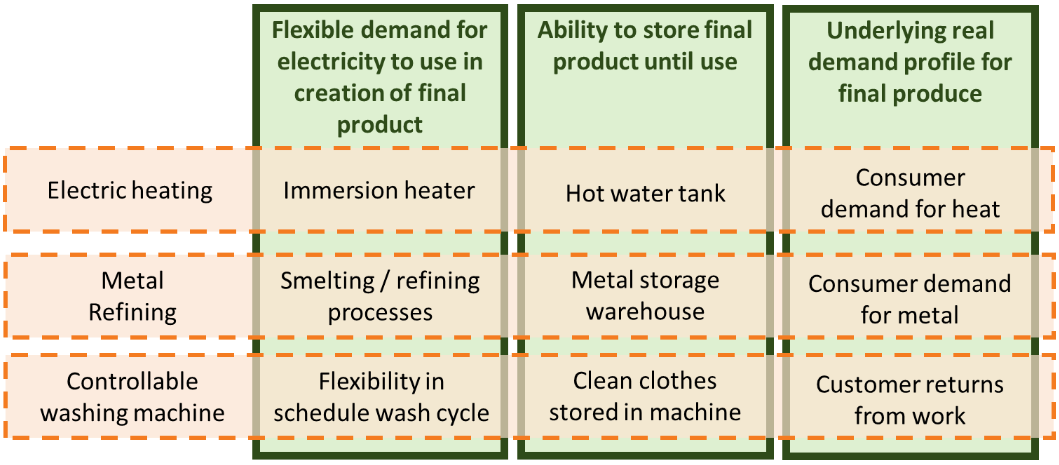

Figure 30: Three components of flexible demand for electricity when modelled as a form of energy storage with example processes

[3] The term 'electrical energy storage' is used in this subsection to differentiate the form of energy storage discussed so far (where energy is taken from and returned to the electrical network) from the storage component of flexible demand discussed here.

Figure 30 gives three examples of processes which could be included in a flexible demand scheme. The provision of flexible domestic electrical heating is being rolled out on the Shetland Islands [5.4]. This process provides houses with heat storage (hot water tanks and storage heaters). Heat storage blurs the line between energy storage as discussed elsewhere in this thesis and flexible demand. Here it is defined as flexible demand because it does not involve the return of electrical energy to the power network. Metal refining is an example of an industrial process which requires large quantities of energy but may provide flexible demand [5.16]. Once a metal such as copper has been extracted from ore it can be stored until needed. The processed copper can be thought of as embodying the electrical energy used to create it. Finally, washing machines are an example of a small-scale domestic appliance which can provide flexible demand through the interaction with signals provided from smart meters, again the clean clothes stored in the washing machine after the spin cycle can be thought of as embodying the energy used to clean them.

This conceptual view of flexible demand including a form of storage allows it to be modelled in a similar way to electrical energy storage. Figure 31 shows models of (a) electrical energy storage and (b) flexible demand for comparison (Figure 31 (a) repeats Figure 13). Flexible demand differs from energy storage in that it does not provide the ability to return energy to the grid, and through the input energy conversion process and the store, electrical energy is used to meet an exogenously-defined demand profile for the final product.

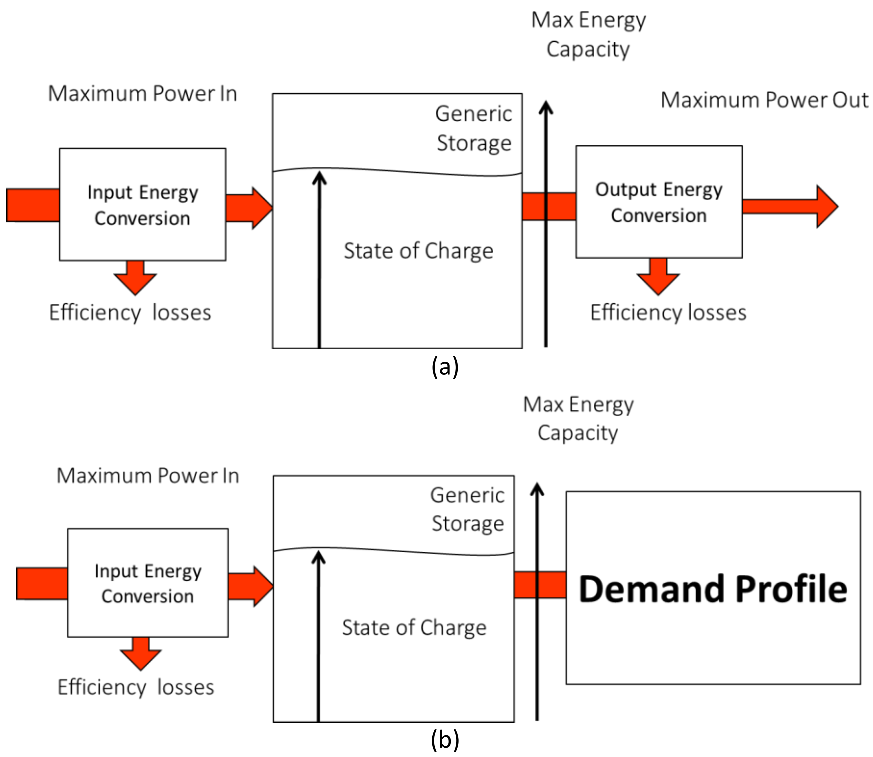

Figure 31: Comparison of models for (A) energy storage and (B) flexible demand components

Using this concept, the following formulation of energy storage is used in this thesis.

The total energy delivered to the load across the time-horizon must be equal to the total energy requirement (taking account of efficiency losses in the conversion process):

$$\Delta t \sum_{t=1}^{t_n} P_{FD}(t) = E_{FD} \tag{5.25}$$

where E_{FD} is the total electrical energy to be delivered.

For each time-step, the power delivered is bound by the rated capacity of the load and a minimum power delivery for that time-step, the value of $P_{FD}^{min}(t)$ may be 0 for all time-steps or may be higher to allow for some consumer preference regarding minimum power delivery at predefined times:

$$P_{FD}^{min}(t) < P_{FD}(t) < P_{FD}^{max}; \forall t \tag{5.26}$$

The storage of energy or embodied energy is used to buffer the flexible electrical load from the underlying demand. A state of charge variable analogous to that used in electrical energy storage can be defined as follows:

$$SOC_{FD}(t) = SOC_{FD}(0) + \frac{\Delta t\, \mu}{F_{FD}^{cap}} \sum_{t'=1}^{t} P_{FD}^{c}(t') - \sum_{t'=1}^{t} F_{FD}(t')\, ; \forall t = 1,2, \dots, t_n \tag{5.27}$$

where μ represents the conversion factor between electrical energy and the final product (an efficiency or coefficient of performance); $F_{FD}(t)$ is the time-series of demand for the final product; F_{FD}^{cap} is the maximum capacity of the final product that can be stored and SOC_{FD} is the fraction of storage used.

If the final product can be accounted for as a form of energy, for example heat, the equation can be re-written with F_{FD} replaced by a power and F_{FD}^{cap} replaced by an energy variable. For the example of heat storage this gives:

$$SOC_{FD}(t) = SOC_{FD}(0) + \frac{\Delta t\, \mu}{E_{heat}^{cap}} \sum_{t'=1}^{t} P_{heat}^{c}(t') - \frac{\Delta t}{E_{heat}^{cap}} \sum_{t'=1}^{t} P_{heat}^{d}(t')\, ; \forall t = 1,2, \dots, t_n \tag{5.30}$$

constraints on the state of charge are the same as those for energy storage:

$$SOC_{FD}^{min} < SOC_{FD}(t) < SOC_{FD}^{max}\, ; \forall\, t \tag{5.31}$$

$$SOC_{FD}(0) = SOC_{FD}(t_n) \tag{5.32}$$

where (5.31) maintains the state of charge within its limits at each time-step and (5.32) ensures that initial and final states of charge are the same.

5.3.8 Summary of the Dynamic Optimal Power Flow formulation

The group of equations and inequalities (5.1) – (5.32) defines the DOPF problem used for ANM schemes. Unlike the existing literature it combines: non-firm generation;

principles-of-access for non-firm generators; a full mathematical description of energy storage; and a model of flexible demand similar to that used in energy storage.

For ease of reference, the mathematical formulation is repeated in Appendix 1 in summary form. The following section of this chapter provides a simple case study which shows the application of the formulation in a realistic actively managed distribution network. The formulation is then applied to the case study of Chapter 7.

5.4 Case study

The DOPF formulation above is demonstrated on a distribution network with some meshing and radial feeders typical of a rural distribution network. It is based on the UK Generic Distribution System simplified rural Extra High Voltage network [5.17], and an outline of the network is shown in Figure 32. The network is at 33kV with a single generator at the swing bus representing the GCP and able to inject or absorb real and reactive power into the network. The transformers linking the network to the transmission network are not modelled, as discussed in Section 5.3.2. Voltage control devices on the network are disabled with the exception of reactive power provision from energy storage. The action of on load tap changing transformers and voltage regulators is not modelled, but their inclusion is discussed below. This allows the study to focus on the role of the novel developments of Section 5.3, namely the scheduling across time of energy storage and flexible demand and the modelling of a principle-of-access for non-firm generation.

Distributed wind generation and ANM components are added to the network as shown in Figure 32 and the parameters used are listed in Table 12. The time-series for demand and available wind generation are shown in Figure 33; all-wind generation is assumed to be exposed to the same wind profile. The optimisation-horizon is 24-hours, split into 15-minute time-steps. Fixed demand at each bus and available generation at each wind farm is the product of total capacity and the relevant normalised time-series. Voltage limits are set to +/- 10% of nominal. As wind penetration is high, the objectives for the optimisation are referred to as *maximising export* and *maximising revenue.* The following scenarios are modelled, the key features of these scenarios are listed in Table 2:

I) Firm and non-firm wind only; maximise export objective; priority order principle-of-access with a value of the priority constant $k = 0.01$ in equation (1a); No other ANM devices are added.

II) As for Scenario I with the addition of energy storage.

III) As for Scenario II with the addition of flexible demand. Flexible demand replaces the equivalent fixed demand so that total energy demand is the same as for scenarios I and II.

IV) As for Scenario III using the maximise revenue objective.

In scenarios III and IV, two flexible demand units are added: one at bus 2 and one at bus 6. The unit at bus 2 represents a relatively large industrial process with a constant demand for power and a fixed output requirement across the 24-hour optimisation-horizon. The unit at bus 6 represents a smaller scale energy process with low but flexible demand for example flexible heat provision.

In this case study, for all scenarios, all wind is assumed to operate at unity power factor. The energy storage device, when added is able to operate in four-quadrant operation with the import/export limit applied to apparent power.

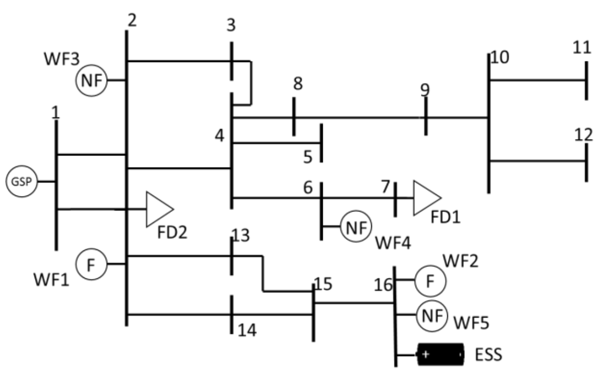

Figure 32: Case study distribution network for Chapter 5. All generators represent wind farms and additional ANM devices are shown connected.

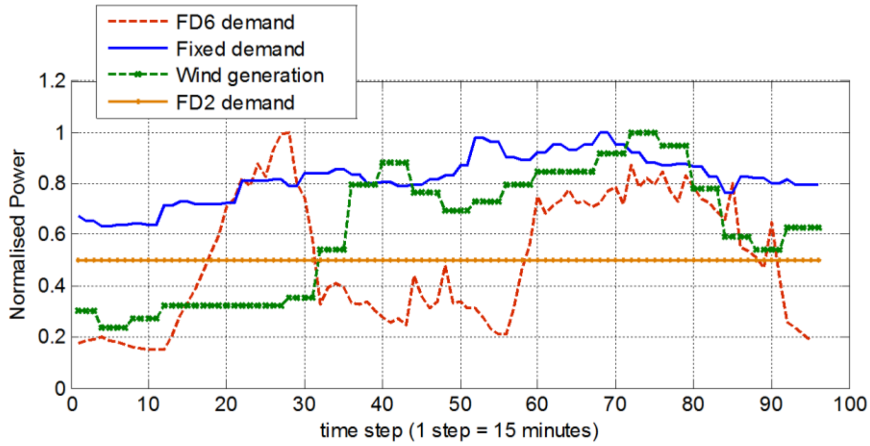

Figure 33: Normalised input time-series. All time-series have been normalised against their maximum value.

Table 12: Parameters of distributed generation and active network management components

Component	Scenario				Variables
	I	II	III	IV	
Time-steps	✓	✓	✓	✓	$t_n = 96\,; \Delta t = 0.25\ hours$
WF1 (Firm)	✓	✓	✓	✓	$P_g^{Capacity} = 40MW$
WF2 (Firm)	✓	✓	✓	✓	$P_g^{Capacity} = 9MW$
WF3 (NF)	✓	✓	✓	✓	$P_g^{Capacity} = 30MW; p = 1$
WF4 (NF)	✓	✓	✓	✓	$P_g^{Capacity} = 25MW\ ; p = 2$
WF5 (NF)	✓	✓	✓	✓	$P_g^{Capacity} = 20MW\ ; p = 3$
Energy storage		✓	✓	✓	$SOC_{max} = 18MWh$ $P_{max}^{charge} = P_{max}^{discahrge} = 3MW$ $SOC_0 = SOC_{final} = 9MWh$ $\varepsilon_c = \varepsilon_d = \sqrt{0.7}$
FD2			✓	✓	$SOC_{max} = 500MWh\ ; P_{max}^{charge} = 6MW$ $SOC_0 = SOC_{final} = 250MW$ $E_{required} = 106MWh;\ \mu = 1$
FD6			✓	✓	$SOC_{max} = 10MWh\ ; P_{max}^{charge} = 2MW$ $SOC_0 = SOC_{final} = 5MW$ $E_{required} = 37MWh\ ;\ \mu = 1$

5.4.1 Implementation

The DOPF has been implemented in conjunction with the MATPOWER suite for power system analysis [5.18, 5.19]. The extensible architecture of MATPOWER allows for easy customisation of standard OPF problems. MATPOWER's own Interior Point Algorithm (MIPS) is used as the solver. On a quad-core 3GHz desktop computer the optimisation solves in approximately 3 seconds for a DOPF network with 1536 nodes and 1152 control variables. A summary manual for the software developed to implement DOPF is provided in Appendix 2.

5.4.2 Case study results

Results for curtailment, exported energy, and losses are shown in Table 13, which also shows revenue from export in scenarios III and IV.

Table 13: Results showing wind farm curtailments, net exports and losses for scenarios I – IV and revenues for scenarios III and IV.

Scenario	**I**		**II**		**III**		**IV**	
Curtail-ment	*MWh*	*%*	*MWh*	*%*	*MWh*	*%*	*MWh*	*%*
WF3	0	0	0	0	0	0	0	0
WF4	59.2	16.0	51.2	12.9	41.6	11.2	43.9	11.8
WF5	163	54.9	155	49.5	147	49.5	145	48.9
Total:	222	17.6	206	16.1	189	15.0	189	15.0
Export (MWh):	960		972		988		987	
Revenue (£10,000)	*N/A*		*N/A*		*(7.96)*		8.06	
Losses (MWh)	55.2		59.3		60.8		61.6	

5.4.2.1 Scenario I – non firm wind only

The results in Table 13 show that when the system is operated as a curtailment scheme only (i.e. without energy storage or flexible demand), 17.6% of the available non-firm generation is curtailed across the whole day. This curtailment is distributed in line with the priority order, with the highest priority wind farm receiving no curtailment and the lowest priority generator receiving the most, at 55% of its output. The time-series of curtailment for WF4 and WF5 is shown in Figure 34 for scenario I. In this figure:

- WF5 is fully curtailed during 16 time-steps and at these times WF4 is partially curtailed.
- There are 25 time-steps (out of 96) when WF4 is not curtailed and WF5 is partially curtailed.
- There are also 24 time-steps where both WF4 and WF5 are partially curtailed.

The first two observations represent times when the limiting constraint is power export from the network and are in line with the priority order. Curtailment is applied first to WF5 until that is fully curtailed, then applied to WF4. The third observation identifies times where local thermal constraints on the line between bus 4 and bus 6 limit the output from WF4 without affecting the output from WF5. The times when each of the thermal constraints is binding is shown in Figure 34 (C). Note that in the case study modelled voltage limits do not cause curtailment. This mirrors the case of existing UK ANM schemes on Orkney and Shetland.

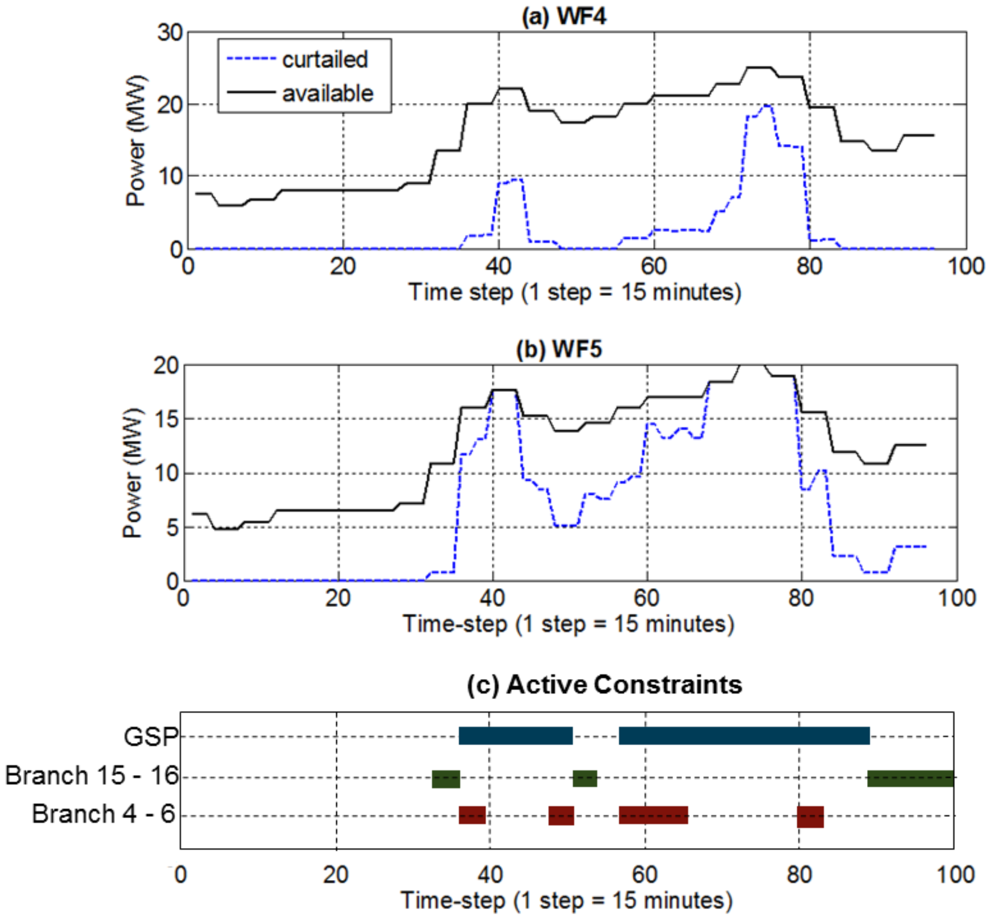

Figure 34: Curtailed wind for (A) WF4 and (B) WF5 in scenario I. WF4 and WF5 are the 2nd and 3rd priority non-firm generators respectively. WF3, which is the 1st priority non-firm experiences no curtailment; (C) shows the thermal constraints that are active and leading to curtailment

5.4.2.2 Scenario II - energy storage

The addition of energy storage increases the energy exported by 12MWh (1.3%) and reduces curtailment by 16MWh (1.5%) (see Table 13). The time-series of energy storage state of charge is shown in Figure 35 and the charge schedule in Figure 36. The decrease in curtailment is more than the rise in export because the total losses – which include efficiency losses in the store – increase by 4MWh.

Figure 37 confirms that that the optimal results produced by the model does not charge and discharge the store at the same time; at each time-step at least one is at zero.

A useful way of benchmarking the benefit provide by energy storage is to take the ratio between the increased export and the total amount of energy it could time-shift across the 24-hour optimisation-horizon. A 3MW, 18MWh unit can in total time-shift 36MWh in a day; accounting for the round-trip efficiency of 77%, the most it can discharge in 24 hours is 27.7MWh. Normalised in this way means that the increase in export of 12MWh equates to 43% related to maximum discharge.

From Figure 35 it is observed that the state of charge reaches its minimum level (at approximately time-step 30) therefore maximising the utilisation of the store within a single charge-cycle. Given the distribution of curtailment throughout the day, greater use of the store could be achieved if the initial and final states of charge were greater than 0.5.

The storage device is located at the same bus as WF5 and is able to directly manage congestion on the line linking it to the rest of the network. However, during time-steps where WF4 is constrained due to congestion in exporting from the network (between buses 1 and 2) rather than due to congestion local to it, the energy store is reduces the curtailment of WF4.

As well as managing real power, the energy store is able to manage reactive power. Figure 36 shows the change in curtailment between scenarios I and II as well as the real power injection of the of the energy storage device. For example, during time-steps 56 – 67 there is no real power charge or discharging of the store, but there is a reduction in curtailment. Although the store is not injecting or absorbing real power, it is injecting reactive power. Using time-step 60 as an example, with no energy storage the thermal constraint is active at the GSP and the apparent power flow out of the distribution network is 60MVA. This consists of 58.58MW real power export and 12.96MVar reactive power import. The energy storage is able to inject a reactive power of 3MVar reducing the reactive power import from the GSP to 10.52MVar. This allows the real power export to increase to 59.07MW, an increase of 0.49MW leading to an increase in generation of 0.77MW from WF5. Total losses across the network increase because additional real and reactive power flow from Bus 16 down to Bus 2. The management of real and reactive power combine during some time-steps, for example during time-steps 51 – 55.

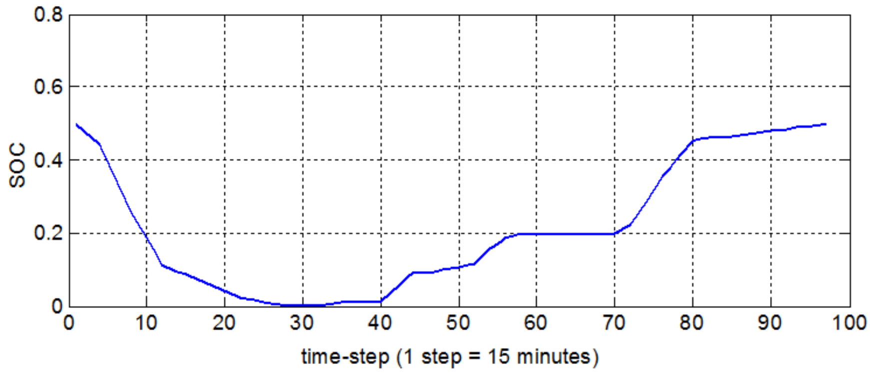

Figure 35: State of charge for energy storage in Scenario II

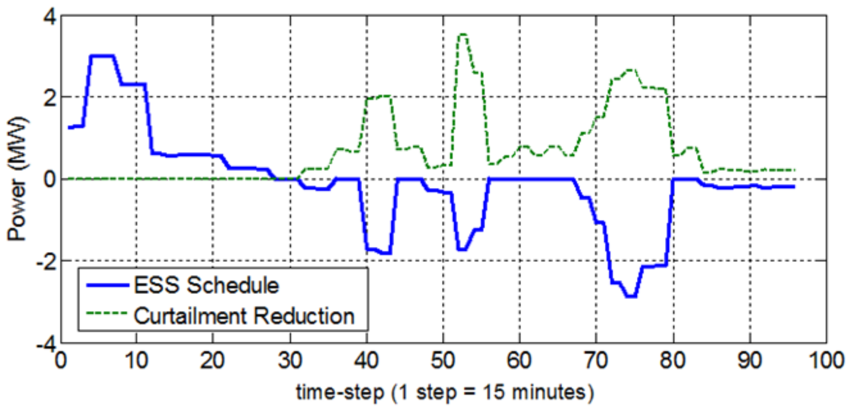

Figure 36: Overall charging / discharging schedule for energy storage and reduction in curtailment for scenario II.

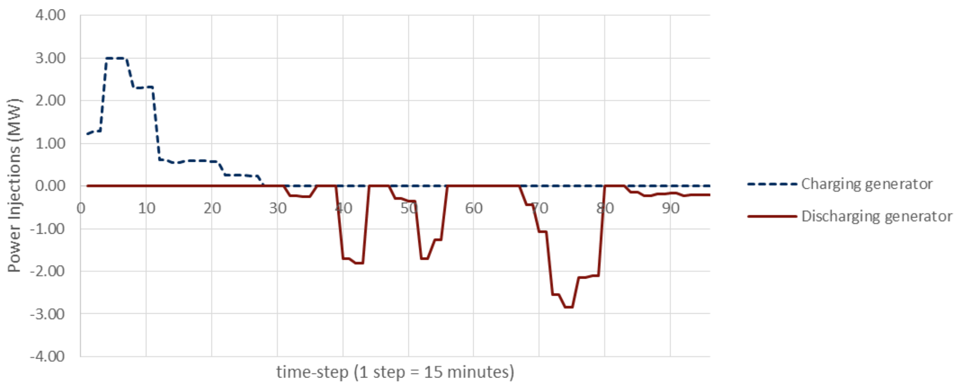

Figure 37: Separate actions of charging and discharging components of energy store, confirming that at most one operates during each time-step.

5.4.2.3 Scenario III – flexible demand

The replacement of fixed demand with flexible demand leads to a further reduction in curtailment and a rise in export. The flexible demand is scheduled by DOPF for time-steps where it reduces curtailment. Figure 38 shows the schedule for the flexible demand unit at bus 7 and the curtailment experience by WF4 with and without flexible demand: the demand has been moved to coincide with time-steps of curtailment, and leads to a reduction in that curtailment. The flexible demand at bus 2 is not local to either of the wind farms, but by managing congestion on the export constraint it further reduces curtailment at both WF4 and WF5. Figure 39 compares the dispatch of flexible demand with apparent power flow from the GCP. It shows that the flexible demand unit is scheduled to use power at full capacity during periods of high power export from the network.

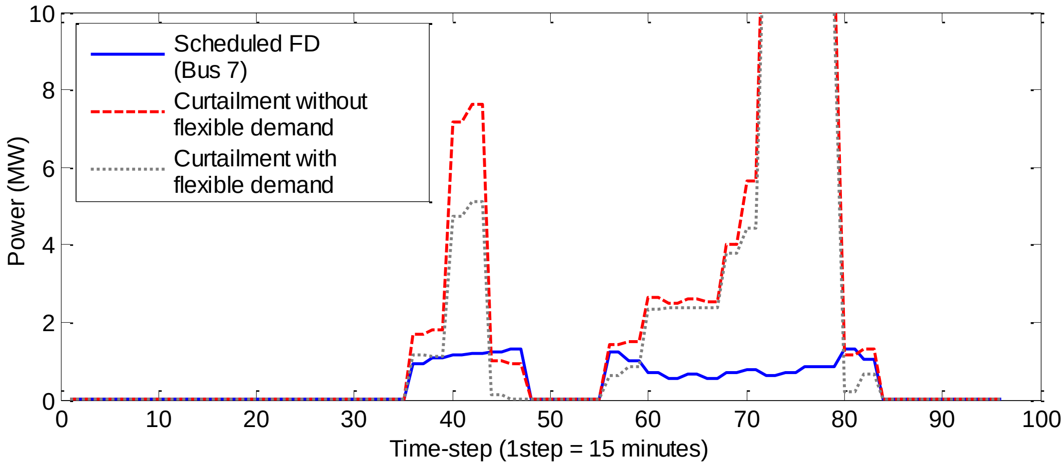

Figure 38: Schedule of flexible demand at bus 7 compared and effect on curtailment at WF4 in scenario III

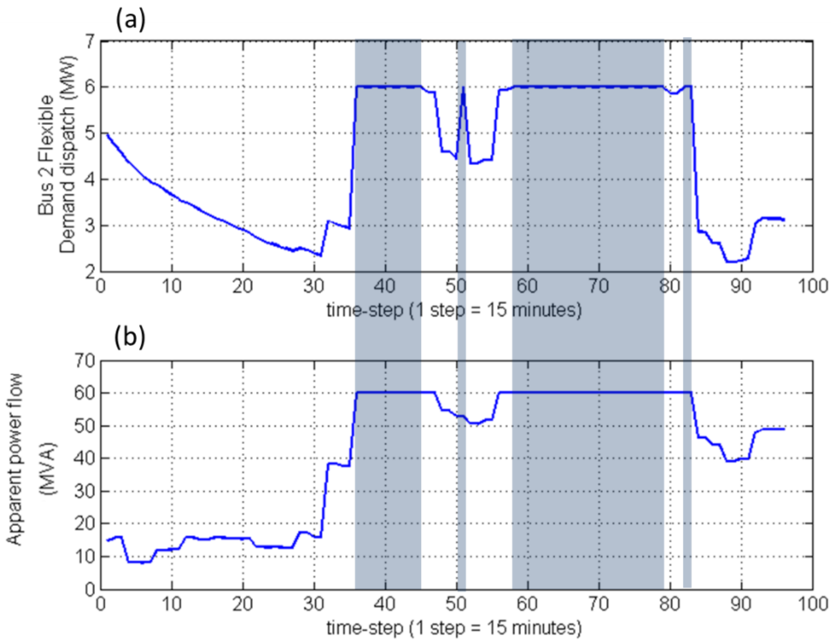

Figure 39: (a) dispatch of flexible demand unit at bus 2 compared with (b) apparent power flow through the GSP in scenario III. The flexible demand is scheduled during periods of high export from the network to reduce curtailment during these times.

5.4.2.4 Scenario IV– maximising revenue

The network set-up for scenario IV is the same as that for III, with the objective changed to reflect the external market price for energy. This change in objective leads to a number of changes in the optimal solution: firstly the total energy export is very slightly smaller, but there is a change in the timing of export to coincide with time-steps of high market price. When compared to the revenue that would be raised by the results for the previous scenario there is a rise of 1.3%. Figure 40 shows the change in export between the two scenarios and the market price. When the export is not constrained the 'maximise revenue' objective leads to reduced export when price is low and increased export when price is high. Time-steps with no change between the scenarios are those where the export link is at full capacity.

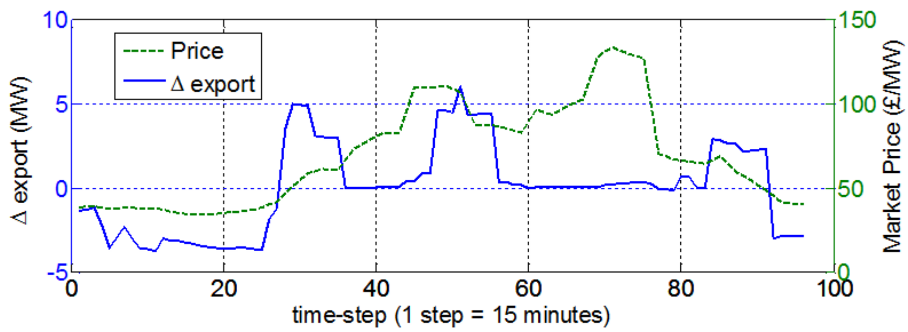

Figure 40: Change in export between scenario III (maximise export) and scenario IV (maximise revenue), positive values represent greater export under revenue

5.4.3 *Case study discussion*

The case study scenarios illustrate that the DOPF formulation presented can be successful in producing optimal dispatches for energy storage and flexible demand in an ANM context. Using DOPF to schedule intertemporal devices leads to a rise in exported energy of 2.9% compared with a simple curtailment scheme. It successfully models LIFO principle-of-access, distributing the curtailment according to the priority order without needlessly curtailing generators that do not contribute to a constraint. The model developed for energy storage is shown to be successful in terms of providing the flexibility required to fully model energy storage. Results verify that the optimisation does not schedule charging and discharging at the same time. The case study also demonstrates the ability to schedule flexible demand and as such demonstrates that the modelling framework has met its aims.

The simple case studies also raises some important issues for the operation of future ANM schemes involving intertemporal devices. It is interesting to identify which non-firm generator benefits most from the addition of intertemporal flexibility. In the case modelled the decrease in curtailment at WF4 and 5 is similar when energy storage and flexible demand is added. This is because of the different constraints acting at different times of the day. Figure 41 shows the reduction in curtailment across the day at WF4 and WF5, it also highlights the times at which the thermal limit local to WF4 is binding. During periods where this limit is not binding, the flexible demand does not reduce curtailment at WF5 at all, in fact during time-steps 52 and 53 there is a small increase in curtailment at WF5. Under the LIFO principle-of-access, the adjusted objective considers WF5 to have a slightly higher 'cost' compared to WF4. As such, the optimisation chooses to use the energy storage and flexible demand to reduce curtailment at WF4 over WF5. This is equivalent to extending the *principle-of-access* used for network access and applying the same principle to access to intertemporal flexibility. However, in this case if a distribution network operator were to use the results of such as optimisation they would be actively controlling technology to assist one non-firm generator over another. This raises the questions of a principle-of-access to intertemporal flexibility and the role of the distribution network operator in applying this. With the introduction of intertemporal technologies owned or controlled by network operators in Shetland and Orkney in the coming years, it is an important point to consider.

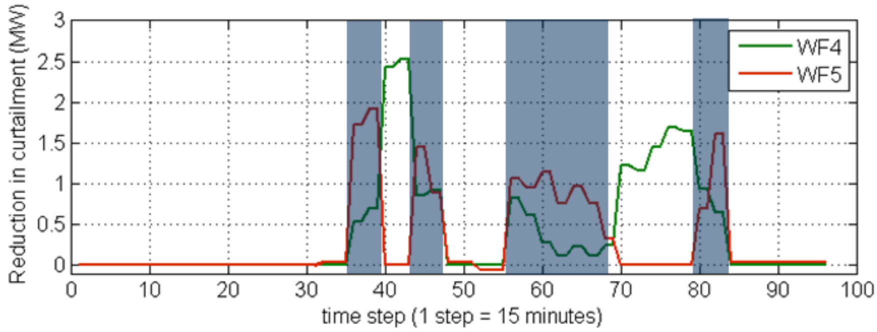

Figure 41: Reduction in curtailment at WF4 and 5 with the addition of flexible demand. The shaded areas show when the line between bus 4 and 6 (local constraint for WF4) is constrained.

DOPF can be used to investigate the effect of the sizes and location of optimally operated energy storage and flexible demand units. Table 14 shows the total export increase (compared with scenario I) if the location and size of the storage in scenario II is varied. For a similar sized energy storage unit, locating it at bus 2 rather than bus 16 leads to greater increases in exported energy, as it is able to more effectively utilize curtailment from more than one non-firm wind farms. Losses are also lower but in both locations, continuing to increase the capacity of energy storage leads to diminishing returns in terms of increased export. This results reinforce the result from the linear programming of optimisation of Chapter 4 that the marginal benefit of energy storage quickly drops off as capacity increases.

Table 14: Export increase relative to scenario I for variations in size and location of energy storage

Location (Bus)	Size (MW / MWh)	Export Increase (MWh)	Export increase per MW of ESS (MW)
16	3 / 18	12.8	4.3
16	15 / 90	42.8	2.9
16	30 / 180	48.2	1.6
2	3 / 18	19.2	6.4
2	15 / 90	49.0	3.2
2	30 / 180	51.3	1.7

The focus on intertemporal technologies compliments existing work which studies voltage control techniques. For example in [5.20] a coordinated control scheme is used to model a larger version of the current network. The formulation allows the secondary voltage of on load tap changers to vary within a specified range according to:

$$V_b^- \leq V_{b_{OLTC}} \leq V_b^+ \tag{5.33}$$

Where V_b^- and V_b^+ are the upper and low voltage bounds at bus b and $V_{b_{OLTC}}$ is the voltage at the controlled side of the on load tap changer. As with other technologies this can be implemented at each time-step of a DOPF by simply extending the $V_{b_{OLTC}}$ to a time-series and setting it within limits for each time-step.

5.5 Conclusions

This chapter has introduced the detailed theory of DOPF. It presents the formulation of a non-linear optimisation problem to incorporate both energy storage and flexible demand.

The chapter notes that intertemporal flexibility plays a similar role to electrical circuits in a DOPF problem and so the mathematical formulation is similar, in that both technologies are modelled as branches linking nodes within the network. Both intertemporal flexibility and electrical circuits are defined as *energy vectors* in this context.

The mathematical formulation of the DOPF problem models the intertemporal aspects of ANM; it extends the existing models of energy storage and provides a new context for considering flexible demand.

A case study of a realistic distribution network with flexible demand, energy storage and generation curtailment is given to illustrate the effectiveness of DOPF at scheduling intertemporal flexibility to maximise exports (equivalent to minimising imports) and maximise revenue (equivalent to minimising costs). It highlights the ability of the method to schedule flexible demand and energy storage and to apply a priority-order principle-of-access. These are important steps for modelling second-generation ANM as well as other applications of these technologies within the electrical network.

The deployment of DOPF to an operations example of an ANM scheme is presented in Chapter 7, together with the detail of how it is customised to meet the requirement of a specific project.

The next stage in developing the theory of DOPF is to study the economic information in an optimal solution, this is the subject of the next chapter.

This chapter has presented the work related to the development of the necessary theory to analyse second-generation ANM schemes and maximise the benefit from non-firm distributed wind generation.

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Chapter 6: Dynamic Locational Marginal Pricing

IN ECONOMICS THE CONCEPT of an efficient market involves the balance of supply and demand leading to an equilibrium price. A constrained electricity network can be thought of as consisting of separate markets for electricity at each network location and at each point in time. The physics of electricity systems is such that demand at a particular time must be satisfied by electricity generated at that time. The marginal cost of meeting demand in geographically and temporally separated markets includes the cost of generating and the cost of moving the commodity from the point of generation to the point of demand. Prices vary by location because of different costs associated with meeting demand at that location – either due to electrical losses in transporting electricity over the network or due to congestion which limits the generators able to supply demand at each location. Prices vary by time because changing the demand level changes the marginal generator, that is the most expensive generator needed and therefore the marginal cost of meeting demand.

Markets for electrical energy defined by location are used in a number of transmission-level power systems. For example in North Eastern United States several markets use Locational Marginal Pricing (LMP) - New York, PMJ and New England [6.1-6.3]. The idea of applying the same method to distribution networks has been proposed in [6.4] although until the development of active distribution networks the communication systems to enable this have not been in place.

LMPs are tied to the concept of Optimal Power Flow (OPF) through the Lagrangian multipliers on nodal energy balance constraints. The multipliers, when determined, give the marginal cost of demand in the units of the objective function. The extension of OPF to Dynamic Optimal Power Flow (DOPF) developed in Chapter 5 suggests a similar extension of LMPs to Dynamic Locational Marginal Prices (DLMPs), again representing the marginal cost of meeting demand at each node of the DOPF network. The DOPF interpretation is that these nodes represent a bus at a particular time, and the DOPF solution will define DLMPs across the network and the optimisation time-horizon. The DLMPs will be modified by the physical flow of energy through intertemporal branches linking time-steps, so that for example, the generation meeting marginal demand at one time-step may occur elsewhere on the network and at a different time.

This chapter presents the theory of DLMPs and provides a number of simple examples to illustrate the concept. The DLMP method is then applied to an islanded distribution network case study in Chapter 7.

6.1 The economics of Optimal Power Flow and Dynamic Optimal Power Flow

As well as defining the optimal dispatch of generation according to an objective function, the solution to an OPF problem provides information on the marginal cost of constraints imposed by the mathematical formulation of the problem [6.5, 6.6]. In the solution these marginal costs are available from the Lagrangian multipliers of the equality constraints and the multipliers on the inequality constraints (see Section 3.1 for more details).

An important sub-set of the Lagrangian multipliers are those associated with the energy-balance constraint at each node. If generation costs are defined in terms of marginal costs of production, these multipliers give the marginal cost of supplying energy to a particular node. The multipliers can form the basis of a pricing strategy in which the price of electricity at a particular node is equal to the marginal cost of supplying electricity at that node. This pricing method is LMP, otherwise known as nodal pricing [6.5, 6.6].

The concept of LMP can be extended to DOPF networks. In this case the Lagrangian multipliers for energy-balance at a node in the mathematical network can be used as a basis for charging demand and paying generation at a particular bus and a particular time.

In addition to the information provided by the Lagrangian multipliers associated with nodal energy balance, multipliers on inequality constraints provide useful economic information. Those associated with branch-flow limits, bus-voltage limits and generator limits gives the *shadow-price* of the constraint in the units of the objective function. For example, if the multiplier on a power-flow limit is £10/WM, the marginal cost of relaxing that limit is £10/MW. This can be thought of as the marginal benefit of upgrading the network with regards to this limit.

As with LMPs, the concept of shadow-prices extends to DOPF, where the constraints used to model flexible demand and energy storage have their own multipliers and therefore shadow-prices.

The remainder of this section describes in more detail the definition and potential use of DLMP and shadow-prices in a DOPF context.

6.1.1 Overview of Locational Marginal Prices in Optimal Power Flow

The concept of LMPs is best explained via an example. Figure 42 shows a simple 2-bus network with two loads o02f 5MW and two generators: a cheap generator with a marginal cost of £50/MWh; and an expensive generator with marginal cost of

£100/MWh (note this example is illustrative and it is not meant to suggest that the values used are realistic for a physical power system). Consider three situations:

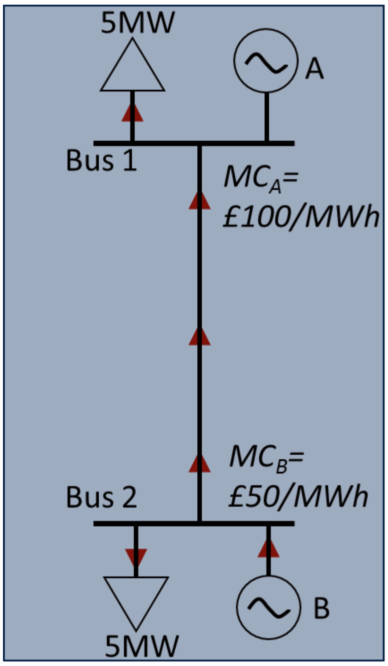

Figure 42: A two-bus power system used to illustrate locational marginal pricing in Chapter 6

1. **The circuit linking Bus 1 and 2 has zero impedance and is not congested.** In this case the optimal solution is to meet the total demand of 10MW from generator B at a marginal cost of £50/MWh. An increase in demand at either bus can be served from generator B without losses, so the marginal costs of meeting demand at both buses is £50/MWh. In this example the LMP is the same at both buses.
2. **The circuit linking bus 1 and 2 has resistance but is not congested.** Resistance in the circuit leads to losses. If losses are currently 1MW, then a total of 6MW must flow into the circuit from Bus 2 to meet the 5MW demand at Bus 1. The marginal costs of meeting the two demands are now different. At Bus 2, the LMP is still £50/MWh, but to meet demand at Bus 1 requires additional generation equal to both the increased demand and the increased losses. If marginal losses

are 0.1MW per 1MW injected by the circuit at Bus 1, the LMP at Bus 1 rises to £55/MWh.

3. **The circuit linking bus 1 and 2 is at full capacity.** In this scenario no more power can be transferred from Bus 1 to Bus 2 within the constraints of the circuit. Meeting additional demand at Bus 1 requires the use of generator A. This has a marginal cost of generation of £100/MWh, so the LMP at Bus 1 rises to £100/MWh. Additional demand at Bus 2 can still be met from generator B, and so the LMP here remains at £50/MWh.

In more complex meshed networks it is not possible to calculate LMP values as readily and instead the optimal dispatch should be calculated via an OPF and the LMP values defined from the Lagrangian multipliers.

The LMP for a particular bus can be decomposed into three components [6.7], in line with the three examples above: an energy cost; the cost of losses; and the cost of congestion. At a general bus, b, the LMP can be written as:

$$LMP_b = LMP_{b_{ref}}^{energy} + LMP_b^{loss} + LMP_b^{con} \tag{6.1}$$

where $LMP_{b_{ref}}^{energy}$ represents LMP at a reference bus, LMP_b^{loss} represents the marginal cost of losses associated with demand at bus b and LMP_b^{con} is the congestion cost associated with the bus. Such a decomposition allows LMPs to be used to inform the sharing of congestion and loss costs [6.7, 6.8].

6.1.2 Merchandising surplus

The use of LMPs can create situations where payments by consumers exceed payment to generators, leading to a surplus of payments, this is known as *merchandising surplus*. It can arise due to network losses and congestions.

Considering the power system in Figure 42 with Generator A removed and no demand at bus 2: generator B is to supply power via the circuits to bus 1. If:

1. **Circuit has zero impedance and is not congested:** prices are the same at both buses, written as π_1 and π_2, and the quantity of energy generated equals that demanded:

$$P_{gen,2} = P_{dem,1};\ \pi_1 = \pi_2 \tag{6.2}$$

As quantity and price are the same for demand and generation, payments from loads exactly equal payments to generators.

2. **Circuit has resistance and no congestion:** in this situation, generation must exceed demand by the quantity of energy lost between bus 2 and bus 1. The price at Bus 1 will be higher to compensate, but it will be higher by *the marginal cost of losses:*

$$\mathrm{LMP}_1 = \frac{\partial C}{\partial P_1} \tag{6.3 a}$$

$$= \frac{\partial C}{\partial P_2}\frac{\partial P_2}{\partial P_1} \tag{6.3 b}$$

$$= \frac{\partial C}{\partial P_2}\left(1 + \frac{\partial P_{loss}}{\partial P_{l\to 1}}\right) \tag{6.3 c}$$

Equation (6.3 a) states the definition of LMP at bus 1 as the rate-of-change of total cost, *C,* with respect to meeting demand at bus 1. In this case, bus 1 demand is met by generation at bus 2 and in equation (6.3 b) LMP_1 is split into the rate-of-change of cost with generation at bus 2 and the rate-of-change of generation at bus 2 with respect to demand at bus 1. This second term includes the increase in losses and can be written in (6.3 c) as the sum of the increase in generation required to meet demand at 1 and the increase in losses with-respect-to the power injected into bus 1 by the circuit linking the two, $P_{l\to 1}$

(due to losses it is important to differentiate the power in to the circuit at Bus 2 and the power out of the circuit at Bus 1). Losses are a convex function of power-flow, so greater power flows lead to higher marginal losses, so the marginal loss rate is always higher than the average loss rate. The result is that the LMP at bus 1 is based on the marginal cost of losses whereas the cost of generation required to cover losses is actually a function of the average rate. In this case:

$$\pi_1 P_{dem,1} > \pi_2 P_{gen,2} \tag{6.4}$$

and more payments are collected from demand than are distributed to generation. The remainder is defined as the merchandising surplus, *MS:*

$$MS = \sum_{n=1}^{n_b} \pi_n P_{dem,n} - \sum_{n=1}^{n_b} \pi_n P_{gen,n} \tag{6.5}$$

The term *surplus* in merchandising surplus is used in the economic sense similarly to *welfare* and analogous to consumer surplus. Using the idea of a separate market at each bus, circuits could be thought of as 'buying' at one end and 'selling' at the other end, merchandising surplus represents the revenue accrued by the circuit above its cost of operation.

3. **Congestion and no losses:** congestion can also create merchandising surplus. Returning to the original example in Figure 42 with two demands and two generators, if the line limit is 4MW (and assumed loss-less), generator B supplies all the demand at bus 2 and the first 4MW at bus 1. Generator A supplies only 1 MW to bus 1, but the high marginal cost of Generator A sets the price for *all* demand at bus 1. Therefore demand at bus 1 pays the high price for 5MW, and generator A is paid the high price for only 1MW. At bus 2 the LMP remains at £50/MWh, so generator B is paid only at this rate for all 9MW generated. The result is that demand payments total £750/hr and

payments to generators total £550/hr. The remaining £200 is a merchandising surplus.

The merchandising surplus can be used to pay the operator of the power system for providing transmission or distribution of electricity. The merchandising surplus created by losses allows the power system to cover the cost of transporting the electricity; the merchandising surplus created by congestion provides an incentive, or a signal, to build additional capacity to reduce the congestion.

6.2 Defining Dynamic Locational Marginal Pricing

The concept of LMP as described briefly above is easily extended to DOPF networks and many of the concepts transfer directly. An example network similar to that in Figure 42 is used to illustrate the concept. The length of the time-steps are set to 1 hour for simplicity as this provides parity between MW and MWh values. Figure 43 shows the network, which consists of two buses, two generators, two loads and three time-steps. In addition there is an energy storage unit that links the three nodes that represent bus 1.

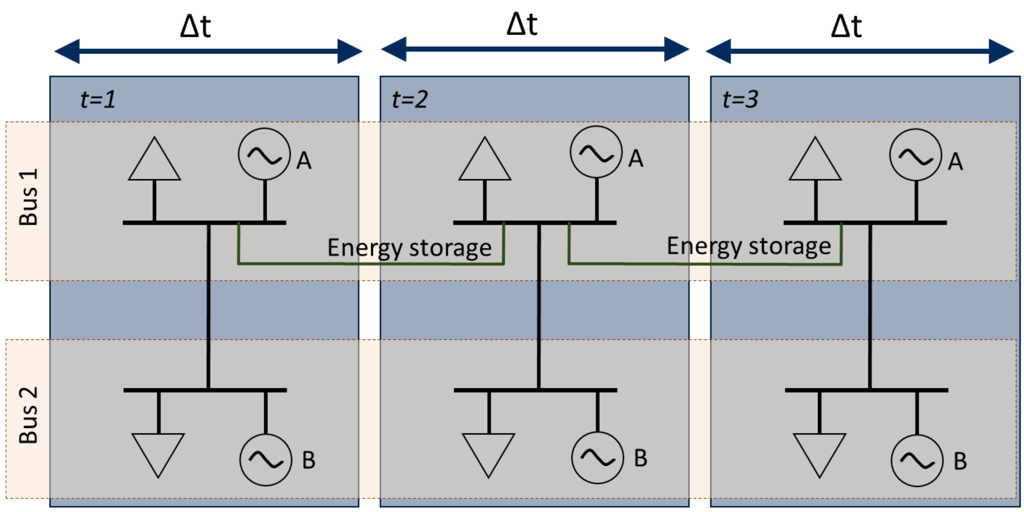

Figure 43: Example 2–bus DOPF network model with three time-steps used to illustrate DLMPs. The power system is the same as that shown in Figure 42.with the addition of an energy storage device linking the three nodes representing bus 1 through time.

Without the energy storage, the mathematical model would consist of three instance of the network in Figure 42 with differing demand values, and each of the three instances could be solved separately to give three sets of LMPs. The addition of energy storage links the three instances.

The definition of the DLMP at a particular bus and a particular time can be written in two ways as defined in Box 3 and Box 4.

DLMP is the marginal cost of meeting demand at a particular bus and at a particular time. Demand can be met by generation located elsewhere on the network and transferred via the power system, or by generation at other time-steps and delivered to the relevant time-step via intertemporal flexibility.

Box 3: Dynamic Locational Marginal Pricing definition based on marginal cost

DLMPs are the values of the Lagrangian multipliers from a DOPF solution on the nodal energy balance constraint for nodes representing particular buses at particular time-steps.

Box 4: Dynamic Locational Marginal Pricing definition based on DOPF Lagrangian multipliers

In the example network of Figure 43, demand during time-step *t=3* can be met using cheap generation from generator B in time-steps *t=1* and *t=2*, and transferred through the power-system circuit to bus 1 and via the energy store to time-step 3. Transferring energy via the power system circuit and by energy storage both involve losses and these losses will form part of the DLMP calculated for the particular nodes, the loss component of DLMP will automatically include the energy storage losses.

As noted in Section 5.2 it is important to differentiate between physical power system *buses* and mathematical network *nodes*. In this section a *node* will be identified by the bus and the time-step that it represents using the following convention: [b=*b*, t=*t*]; for example [b=*2*, t=*1*] refers to the node representing bus 2 at time-step 1.

As an example, consider a demand of 1MW at node [b=1,t=3] served via generation at node [b=1,t=1] and transferred to time-step 3 using the energy storage:

$$\mathrm{DLMP}_{[b=1,t=3]} = \frac{\partial C}{\partial P_{[b=1,t=3]}} \tag{6.6 a}$$

$$= \frac{\partial C}{\partial P_{[b=1,t=1]}} \frac{\partial P_{[b=1,t=1]}}{\partial P_{[b=1,t=3]}} \tag{6.6 b}$$

$$= \frac{\partial C}{\partial P_{[b=1,t=1]}} \left(1 + \frac{\partial P_{loss,store}}{\partial P_{[b=1,t=3]}}\right) \tag{6.6 c}$$

This is the same as the derivation in (6.3) with the losses occurring in the storage rather than in an electrical circuit.

6.2.1 A simple example of Dynamic Locational Marginal Pricing

A simple example of a DOPF solution including DLMPs is given here to clarify the concepts. For ease of understanding, only real power and resistance are included, although the method generalises to a full AC power flow including reactive power as demonstrated in Chapter 7.

The network of Figure 43 is extended to 24 time-steps, each of 1 hour duration. The components that form the network are described in Table 15 and the demand characteristics are shown in Figure 44.

Table 15: Summary of components in example DLMP network for Chapter 6.

Component	Location (Bus)	Characteristics	Comments
Demand	1,2	See Figure 44 below	Assume demand the same at both buses
Generator A	1	$C_B(P_B) = 100P_B + 0.5{P_B}^2$ $P_B^{min} = 0;\ P_B^{max} = 50$	Expensive generator. P_B^{min} , P_B^{max} are the minimum and maximum generator limits for the expensive generator and P_B is the dispatched generaiton
Generator B	2	$C_A(P_A) = 50P_A + 0.5{P_A}^2$ $P_A^{min} = 0;\ P_A^{max} = 50$	Cheap generator
Energy storage	1	$P_{max}^c = P_{max}^d = 1MW$ $E_{max}\ = 5MWh$ $\varepsilon_c = \varepsilon_d = 0.84$; $\varepsilon_{rt} = 0.7$	Where P_{max}^c and $P_{max}^d$are the charging and discharging limits, E_{max} is the energy capacity and ε_c, ε_c and ε_{rt} are the charging, discharging and round trip efficiencies.
Distribution circuit	1 → 2	$P_{max}\ = 11MW$ $R = 0.1\ Ohms$	

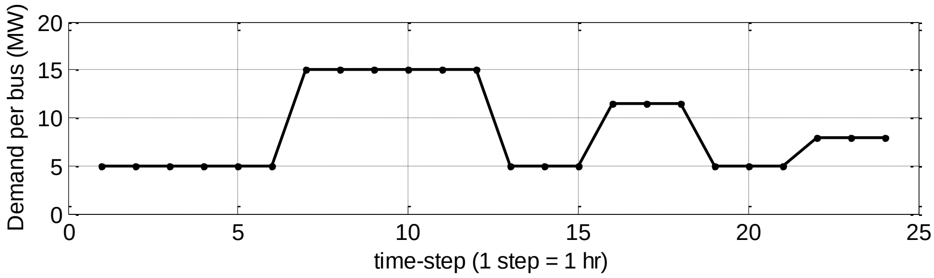

Figure 44: Time-series of demand for example DLMP case study. The same demand profile is used for load at both buses.

6.2.1.1 *Dynamic Locational Marginal Prices without energy storage*

Solving the DOPF without energy storage gives DLMP values equal to the LMPs that would be found by solving an OPF for the power system separately at each of the 24 time-step. The results are shown in Figure 45.

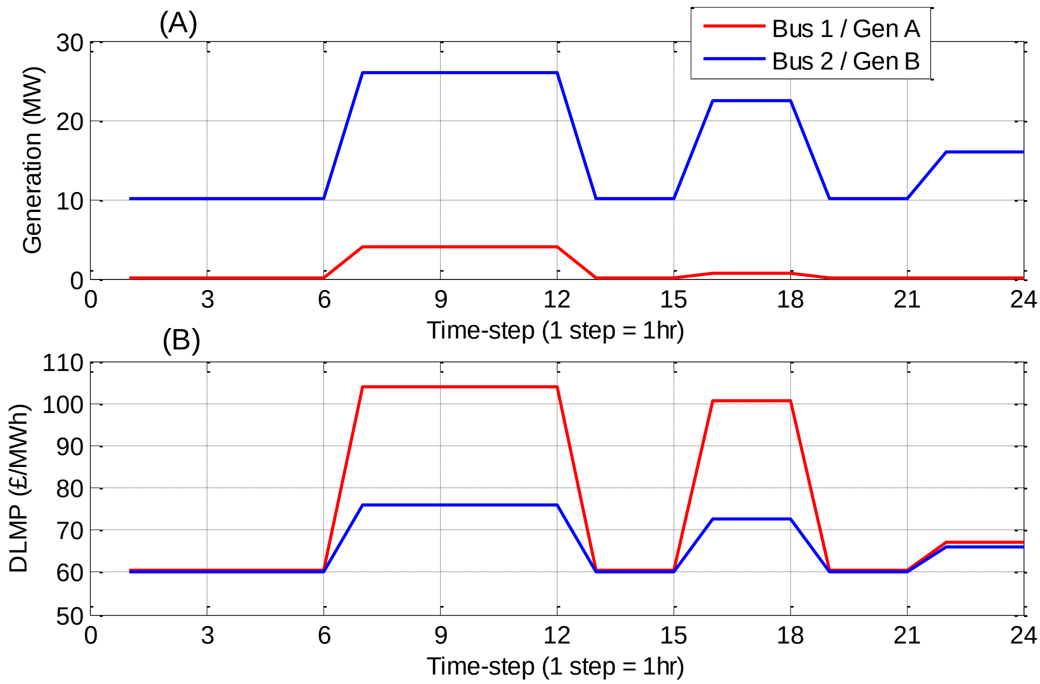

Figure 45: (A) Generation and (B) DLMP values for Bus 1 and 2 with no storage included.

The following key points can be noted from the results:

- During time-steps 1 – 6, 13 – 15 and 19 – 24 only generator B is operating, as there is sufficient capacity on the power-system circuit to supply power to bus 1 from the cheap generator. As such, there is only a small difference between the DLMPs at bus 1 and bus 2 caused by the electrical losses.
- During time-steps 7 – 12 and 16 – 18 generator A operates as the electrical circuit is at full capacity, leading to high marginal costs. There is now a significant difference in the DLMP between the two buses. Note that between time-steps 16 and 18 generator A is only operating at a very low level.

6.2.1.2 Dynamic Locational Marginal Prices with an Ideal 100% efficient energy storage device

If the energy store at bus 1 is added to the optimisation and modelled as 100% efficient[4], it is able to transfer energy between time-steps. The optimal generation schedule, DLMP and storage schedule are shown for this scenario in Figure 46.

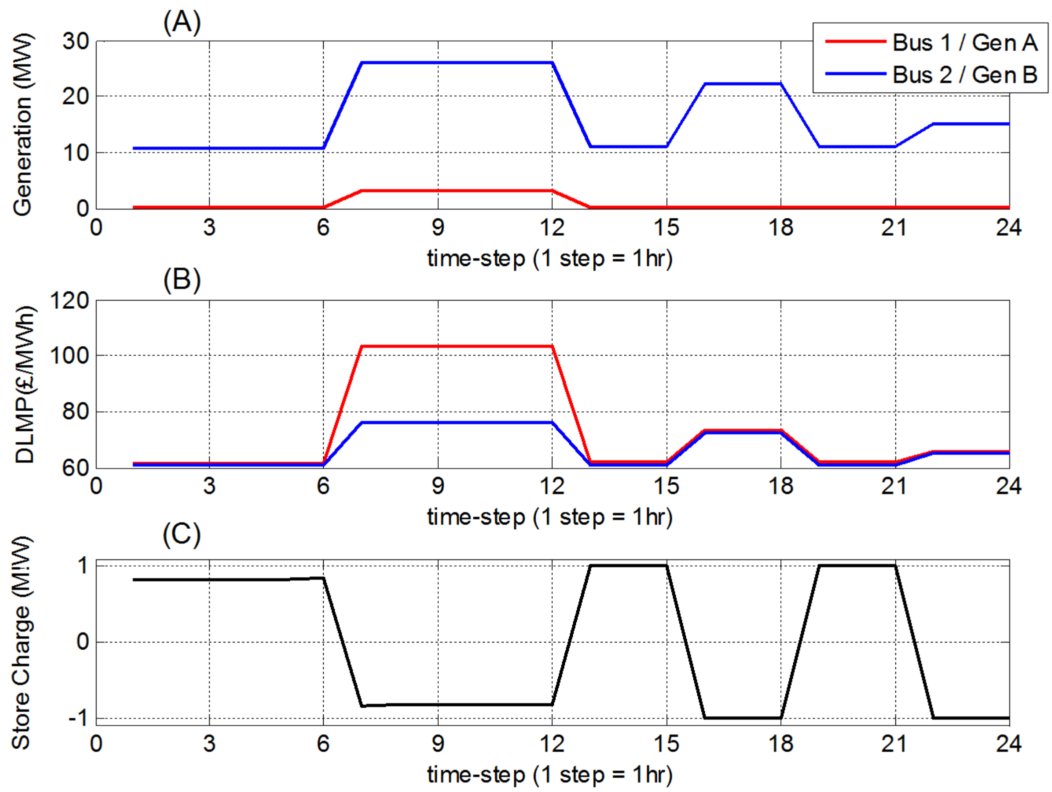

Figure 46: (A) Generation, (B) DLMP and (C) storage schedule for the case where a totally efficient store is added to the test 2-bus network.

[4] As discussed in Section 5.4 the DOPF model of storage required round-trip efficiency to be less than 1. When stated as '100% efficient' in the text, energy storage is modelled with a round-trip efficiency of 99.99%.

The results for the efficient energy store show the following:

- Energy storage charges during time-steps 1 – 6 and discharges during time-steps 7 – 12. The store does not charge/discharge at its full rate of 1MW as there is insufficient energy capacity to sustain charging of 1MW for 6 hours. Charging during time-steps 1 – 6 is carried out using energy from generator B – slightly raising the DLMP during these time-steps (from £60.52/MWh without storage to £61.46/MWh with storage at bus 2). Discharging displaces generation from generator A, slightly reducing the DLMP at bus 1 during time-steps 7 – 12 (from £104.10 to £103.27).
- The charge cycle in time-steps 13 – 18 is able to completely displace the use of generator A during time-steps 16 – 18. This significantly reduces the DLMP at bus 1 during these time-steps (from £100.60/MWh to £73.38/MWh). The bus 1 price during these time-steps is now set by the marginal cost of generation at generator B (nodes [b=2, t=16] – [b=2, t=18]).
- During time-steps 19 – 24, a charge cycle is used to increase generation during time-steps 19 - 21 and reduce generation during time-step 22 – 24.

6.2.1.3 Dynamic Locational Marginal Prices with a 70% efficient energy storage device

To identify the effects of inefficiencies in the energy store, a store with a 70% round trip efficiency is modelled. The results for DLMP and the storage schedule are shown in Figure 47.

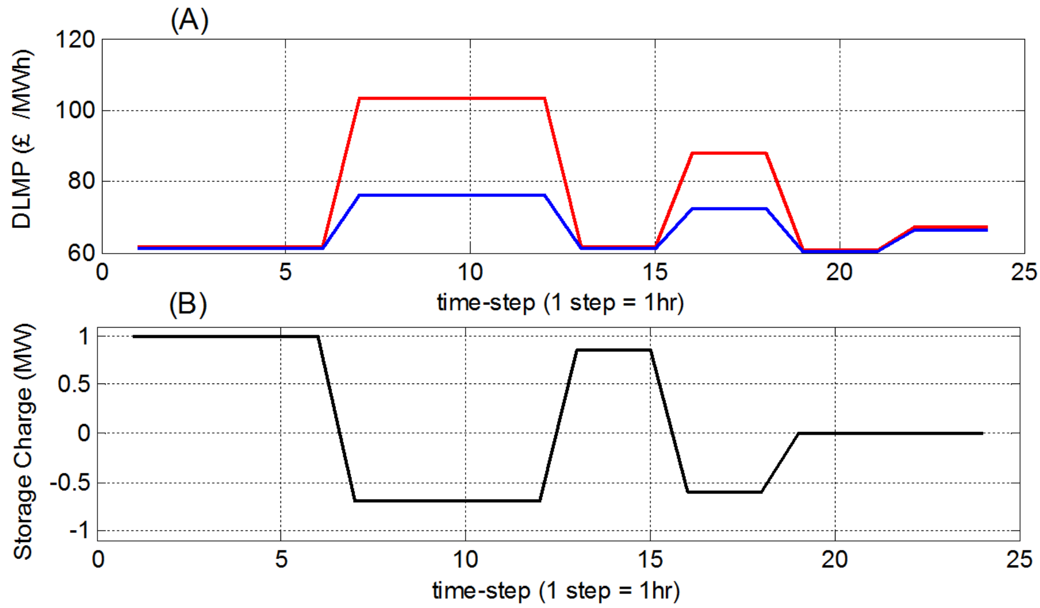

Figure 47: (A) DLMP and (B) storage schedule when an energy store with round-trip efficiency of 0.7 is included in the 2-bus test network.

The key points from these results are that:

- As with the 100% efficiency store, the charge cycle during time-steps 13 – 18 removes the need to operate generator A during time-steps 16 – 18. Generator B during time-steps 13 – 15 sets the DLMP at bus 1 during time-steps 16 – 18, because of the losses incurred by the energy storage, there is a higher marginal cost associated with demand at nodes [b=1, t=16] – [t=1, t=18]. The DLMP of these nodes is higher than when using a 100% efficient storage but are still lower than in the case of no storage.
- The efficiency losses mean that the optimum solution no longer involves a charge cycle during time-steps 19 – 24. The very small decrease in operating costs of the generators is outweighed by the cost of 30% energy losses in the storage. This echoes the result of (4.15): energy storage will only operate if the ratio of DLMPs between nodes at different time-steps is greater than the inverse of the round-trip efficiency:

$$\frac{\pi_t}{\pi_{t'}} > \frac{1}{\varepsilon_{rt}} \quad \text{where } t \neq t' \tag{6.7}$$

Unlike the optimisation used in Chapter 4, the prices π_t and $\pi_{t'}$ here, which represent the DLMP for different time-steps, are now dependant on the power injections of the storage device.

6.2.2 Dynamic Optimal Power Flow shadow prices

As well as affecting the DLMP prices, the energy storage device has associated shadow prices representing the marginal value in relaxing particular constraints.

A storage device is modelled by a collection of constraints on power and energy storage at each time-step, as defined by the equations and inequalities in Section 5.3.

Each constraint has an associated multiplier, and there are $4n_t + 1$ constraints:

- n_t inequalities on power-injections into the device with associated multipliers (5.18). The multipliers on the lower limit (representing negative power injections to the power system) $\mu_{p,charge}(t)$ represent the shadow-price on the charging power limit.
- n_t inequalities on power-injections out of the device and associated multipliers (5.18). The multipliers on the upper limit (representing positive power injection to the power system), $\mu_{p,discharge}(t)$ represent the shadow-price on the discharging power limit.
- n_t constraints and multipliers, $\mu_{E,upper}(t)$ on the upper bound of energy stored in the device (5.20).
- n_t constraints and multipliers, $\mu_{E,lower}(t)$ on the lower bound of energy stored in the device (5.20).
- 1 constraint ensuring the initial and final states of charge are the same (5.21).

The marginal benefit created by increasing the size of either the power or energy storage capacity is the sum of the shadow prices related to that component; upgrading the device simultaneously relaxes all the constraints associated with it. For example, if the same physical component is used to charge and discharge the store, the marginal benefit of increasing the power capacity is given by:

$$MB_{power} = \sum_{t=1}^{n_t} \{\mu_{p,discharge}(t) + \mu_{p,charge}(t)\} \tag{6.8}$$

with energy capacity, there is an additional complication due to the initial and final state of charge. In the DLMP example presented above, the initial and final state of charge are both set to zero. Consider the upper bound on the store:

$$SOC_{store}(\mathrm{t}) > SOC_{store}^{max}\ \forall t \tag{6.9}$$

substituting for $SOC_{store}(t)$ from (5.19) and rearranging to give the constraint in the maximum energy capacity E_{store}^{cap} gives:

$$\frac{\varepsilon_c \Delta t}{E_{store}^{cap}} \sum_{t'=1}^{t} P_{store}^{c}(t') - \frac{\Delta t}{E_{store}^{cap}\varepsilon_d} \sum_{t'=1}^{t} P_{store}^{d}(t') > SOC_{store}^{max} - SOC_{store}(0)\ \forall t \tag{6.10}$$

defining the left hand side of (6.10) as $SOC_{store}^{net}(t)$ and multiplying through by E_{store}^{cap}, the energy capacity of the store, this simplified to:

$$E_{store}^{net}(t) > E_{store}^{cap} - E_{store}(0)\ \forall t \tag{6.11}$$

where in (6.11) $E_{store}^{net}(t)$ is the net energy stored up-to time *t*. Similarly for the lower bound:

$$E_{store}(0) - E_{store}^{min} > E_{store}^{net}(t)\ \forall t \tag{6.12}$$

From (6.11) and (6.12), if the energy storage capacity is increased but the initial state of charge remains the same (for example at zero), there is a relaxation of (6.11) but not (6.12). If however, the initial energy in the store is set to a fraction of the maximum capacity (for example $0.5E_{store}^{max}$) then increasing the size of the storage leads to a relaxation of both (6.11) and (6.12).

In general, for a marginal increase in energy capacity of δE_{store}^{cap}, and an increase in the initial energy stored of $\alpha \delta E_{store}^{cap}$ where α is the fraction of E_{store}^{cap} set for $E_{store}(0)$, the marginal benefit of increasing storage capacity is:

$$MB_{energy} = \sum_{t=1}^{n_t} \{\alpha \mu_{E,upper}(t) + (1-\alpha)\mu_{E,lower}(t)\} \tag{6.13}$$

For the example, where $\alpha = 0$ and $E_{store}(0) = 0$ this becomes:

$$MB_{energy} = \sum_{t=1}^{n_t} \mu_{E,upper}(t) \tag{6.14}$$

To confirm these formulations, results are presented in Table 16 showing the multipliers extracted from the optimal DOPF solution and summed to estimate the marginal benefit, and the change in the objective when the power/energy components are increased by 0.01MW/0.01MWh respectively. Both the DOPF multipliers, and the results of a small change in the optimisation setup lead give the same results confirming the statements of equation (6.8) and (6.13).

Table 16: Comparing the change in objective function with small increases in power and energy capcacity of the store. Row 1 shows the objective value and the value of (6.8) and (6.14) at this point. Row 2 and 3 show the effect of a small change in power and energy capacity and the resulting marginal change in the objective funtion. Results show the equivalence of the two methods.

Storage scenario		Value of objective (£)	Δ Objective (£)	Marginal change in objective	$\sum_{t=1}^{n_t}\{\mu_{p,discharge}(t) + \mu_{p,charge}(t)\}$	$\sum_{t=1}^{n_t}\mu_{E,upper}(t)$
$P_{max}^{c} = P_{max}^{d} = 1MW$; $E_{store}^{cap} = 5MWh$; $E_{store}(0) = 0$; $\alpha = 0$		25,750			£46.9/MW	£41.8/MWh
	$\delta P^{cap} = 0.001$		0.0469	£46.9/MW		
	$\delta E^{cap} = 0.001$		0.0418	£41.8/MWh		

It should be noted that the results presented in Table 16 represent the *marginal* benefit in power and energy when everything else is held constant. So the marginal benefit of increasing the power capacity assumes the energy capacity is held constant. The marginal values appear very small compared with the optimal value of the objective function. However, at lower capacities the marginal value is much higher. Figure 48 (A) shows the change in marginal benefit from the power capacity whilst energy capacity is held constant, and Figure 48 (B) shows the change in marginal benefit from energy capacity as power capacity is held constant. As can be seen in both cases, at small values of power or energy, the marginal benefit is much larger. At a power capacity of 1.7MW, the marginal benefit of increasing power capacity drops to 0. This is because, for the fixed energy capacity, the power capacity is not able to provide further benefits.

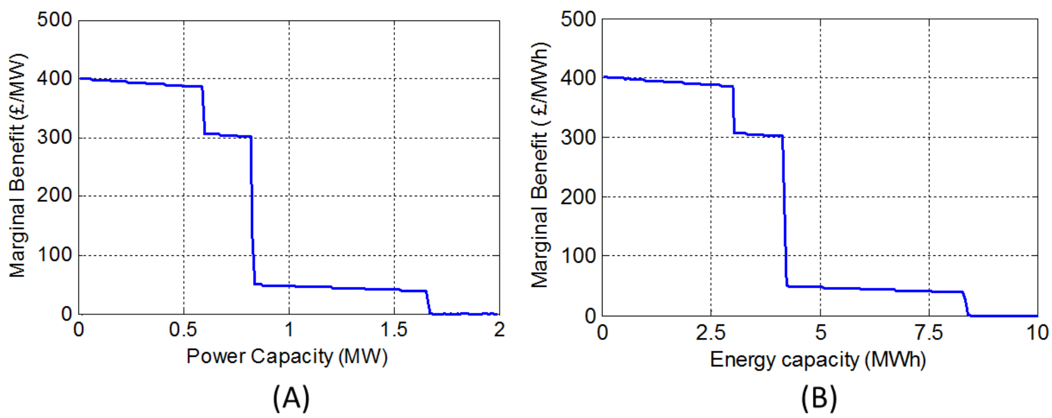

Figure 48: Variation of marginal value of (A) power and (B) energy capacity of the energy storage using shadow prices. In both cases the other variable is kept constant at either 1MW or 5MWh. Note the sharp drop-off as the additional power or energy capacity increases. To increase value both power and energy should be increased simultaneously.

6.2.3 Merchandising surplus in Dynamic Optimal Power Flow

The merchandising surplus of a DOPF problem can be defined in the same way as for an OPF problem: the difference in payments by loads and payments to generators. As with other concepts it will be prefixed by *dynamic* to allow clear differentiation. Dynamic merchandising surplus (DMS) is formally defined here as:

$$DMS = \sum_{m=1}^{n_t} \left\{ \sum_{n=1}^{n_b} \pi_{[b=n,t=m]} P_{dem,[b=n,t=m]} - \sum_{n=1}^{n_b} \pi_{[b=n,t=m]} P_{dem,[b=n,t=m]} \right\} \quad (5.40)$$

The payments and surpluses for the DLMP for the example from Section 6.2.1 are given in Table 17. It shows that the addition of energy storage reduced both the total cost of generation (which is the objective function of the optimisation) and payments by consumers compared to the problem in Section 6.2.1. The payments by consumers goes either to generators or forms the merchandising surplus, both of which drop with the addition of energy storage. The efficient store reduces payments by consumers by almost £1000, which is split between a £290 reduction in payments to generators and a £680 reduction in merchandising surplus.

Payments to generators cover the operation costs of generating power, and leads to a generator surplus. The addition of efficient energy storage leaves the generators surplus almost unchanged, as the reduction in payments to generators is almost completely offset by the cost of generation. The reduction in merchandising surplus provides a signal that energy storage allows a more economically efficient dispatch.

In the case of the 70% efficient energy store, the cost of generation increases slightly and the DMS rises by £280. The increase in DMS is due to losses which in this case include the losses in the storage.

Table 17: Values of payments and economic surpluses with energy storage. The objective function is the total costs of generation. By reducing this, storage also reduces the payments by consumers and affects both the generators' surplus and the merchandising surplus.

Scenario	Total payments by consumers (£)	Total payments to generators (£)	Total cost of generation (£)	Generator surplus (£)	DMS (£)
No storage	32,610	29,890	26,060	3830	2,720
Efficient storage	31,640	29,600	25,750	3850	2,040
Inefficient storage	32,190	29,870	25,970	3900	2320

6.2.4 Dynamic Locational Marginal Pricing with flexible demand

The discussion so far has focused on energy storage. Flexible demand will also affect DLMPs and DMS. In an optimal solution, flexible demand is dispatched to minimise the objective function. When the objective is the minimisation of generating costs and the DLMPs represent the marginal cost of meeting demand at each node, flexible demand will be scheduled during periods of low DLMP at its point of connection.

Flexible demand is modelled in this thesis as a form of energy storage to allow the time at which electricity is drawn to be disconnected from the time at which the end product (either energy or a product that embodies energy) is required. As the underlying demand for energy is now separated from the electrical network, it will pay prices based on the DLMPs at which electricity is drawn rather than when it is used.

The example study from Figure 43 and Table 15 is repeated for the base scenario with half the fixed demand at bus 1 replaced with flexible demand. The underlying demand profile is assumed to be the same as for fixed demand but is buffered by 100MWh of equivalent storage (This represents an excess of energy storage). Figure 49 shows the DLMPs for bus 1 with and without flexible demand and the schedule for flexible demand to draw electricity. Flexible demand is scheduled to coincide with time-steps of low DLMP. The effect on DLMPs is to slightly raise them during periods of low DLMP and reduce them during periods of high DLMP.

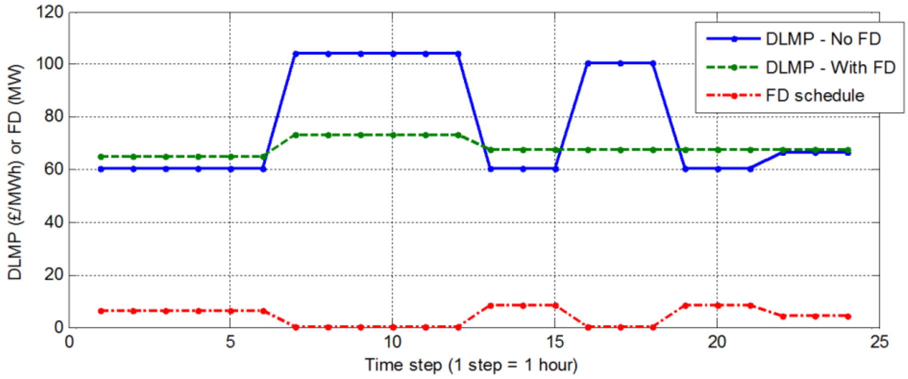

Figure 49: DLMPs for bus 1 with and without flexible demand and the schedule for flexible demand.

As with previous studies using energy storage, the use of flexible demand reduced the need to use the expensive generator B which leads to a big reduction in DLMP during time-steps 7 – 12 and 16 – 18. The payments by consumers drops considerably even though the same quantity of energy is demanded across the optimisation horizon. Table 18 shows how the payments and surpluses with flexible demand compare to the case without. Payments by consumers drop by 12.5% and payments to generators by 4.8%. Generator surplus reduces slightly but the biggest change is in the DMS which is almost completely removed (a reduction of 96.3%). The reason for the huge drop in DMS is the removal of congestion on the power system circuit. Without flexible demand, the circuit is congested during time-steps 7 – 13 and 16 – 18. This leads to the out-of-merit order commitment of generator B and a non-zero congestion component of DMS. The remaining DMS of £100 covers the costs of losses.

Table 18: Value of payments and economic surpluses for case with flexible demand.

Scenario	Total payments by consumers (£)	Total payments to generators (£)	Total cost of generation (£)	Generator surplus (£)	Merchandising surplus (£)
No Flexible Demand	32,610	29,890	26,060	3830	2,720
With Flexible Demand	28,550	28,450	24,690	3760	100

6.3 Discussion of Dynamic Locational Marginal Pricing

The use of DLMP provides a novel way of measuring the value of energy storage, and flexible demand. From a DLMP perspective, energy storage and flexible demand act as network reinforcements, able to be used to (a) reduce the value of objective function of minimising generation costs; (b) reduce payments by consumers, which is one of the key objectives of power system operation; and (c) reduce the DMS which acts as a signal of out-of-merit dispatch of generation.

In the situation modelled, flexible demand is able to almost completely remove DMS leaving only an element related to the losses in the electrical circuit. As modelled here, flexible demand has no associated losses. Energy storage by contrast will have losses associated with it. An oversized energy storage device will not reduce DMS as much as flexible demand due to the additional loss component. To illustrate this, the case study reported in Table 17 is remodelling with an energy store with no power or energy limitation and 70% round trip efficiency. Even with the oversized energy store, the DMS is still £1,800 compared to the £100 achieved with flexible demand. There is no congestion component to this DMS; it comes from the 30% losses in the round trip of the device.

One issue identified as a key problem for dynamic pricing is excessive variability of prices that can result10. In a system where prices fluctuate wildly it is difficult to plan usage, and consumers run the risk of being forced to accept very high prices at some times. One of the advantages of the DLMP view of energy storage and flexible demand is that it can stabilise prices through its action in linking time-steps.

The discussion of DLMPs in this chapterhas been formulated in terms of monetary units. However, the same theory applies whatever the underlying 'currency' of the objective function. Where the objective of the optimisation is to minimise imports from the distribution network, the 'currency' is energy (usually measured in MWh). In this situation the Lagrangian multipliers represent the marginal increase in import required for an increase in demand at a particular bus, this might referred to as Dynamic Locational Marginal *Imports.*

Applying the concept of LMPs and DLMPs to distribution networks involves treating the external and exogenously defined market price as the 'marginal cost' of the grid connection point. In the DOPF developed in Chapter 5, the grid connection point is treated as a generator. If there is to be no wind curtailment, the grid connection point will be the marginal generator and for both importing and exporting situations, additional demand within the distribution network will be met by a net increase in import at the market price.

6.3.1 Wind generation in Dynamic Locational Marginal Pricing

The generators modelled in the simple case study of this chapter represent two conventional generators: a high and a low cost generator. The cost curves for those generators are based on the marginal cost of production and are heavily dependent on the fuel prices and the efficiency with which chemical energy is converted into electricity.

Wind is an example of a technology with very low marginal cost of generation. Once the wind turbine has been built there are no fuel costs and the cost of regular maintenance are not directly related to the operation of the device. As such wind is often modelled as having zero marginal cost of production [6.9]. This places it at the top of the merit order when dispatching generation to minimise costs. Wind generation in the system will reduce the cost of generation as any of its output will have zero associated costs and will offset the need to use more expensive generation.

Firm wind generation may reduce the DLMPs by replacing or reducing expensive generators, however it will never be the marginal generator. By definition all wind generation must be able to be dispatched within the system limits at all times, and there will always be a requirement for other (more expensive) generation which will therefore set the DLMPs. Whilst firm wind can significantly reduce the cost of generation, it may have a smaller effect on the cost to consumers because the expensive generators remain setting the price.

To illustrate this, the example from Section 6.2.1.1 is repeated with the addition of 5MW of wind at bus 1. The wind generation is assumed to generate at full capacity during all time-steps. Figure 50 shows the effect this has on the DLMPs when there is no energy storage or flexible demand. It shows that there is a small decrease in the DLMP when the wind capacity is generating. The cost of generation drops by £6920 but the reduction in consumer payments is minimal dropping by only £2250. The addition of wind reduces the merchandising surplus because the need to use generator A during time-steps 16 – 18 is removed. However, the generator surplus increases significantly by £5850. This is because the wind generation is being paid at the price set by generator A but it has zero operational costs. All payments to this generator therefore counts as surplus. The values of payments and surplus for this scenario is given in Table 19.

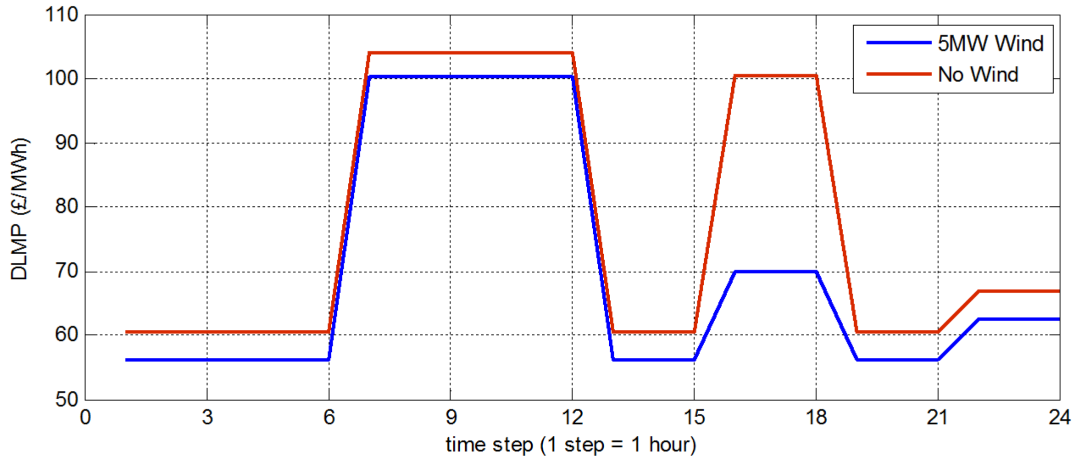

Figure 50: The effect of firm wind generation on DLMPs at bus 1. During time-steps 7 – 12 both conventional generators continue to operate. During time-steps 16 – 18 the expensive generator B is no longer required once wind is added.

The situation with non-firm wind is different. Curtailment applied to non-firm generators due to thermal or voltage limits means that a marginal increase in demand can be met directly by increasing wind generation. In this case the DLMP value can drop to zero. To illustrate the effect of moving from a situation with firm wind only to one with non-firm wind the above scenario is repeated twice with 9.9MW and 10.1MW of wind. In this simple system, with no minimum limits on the conventional generation, 11MVA thermal rating on the line and a system demand minimum of 10MW, the system can always accommodate 10MW of wind generation.

The system with 9.9MW of wind generation therefore requires no curtailment, and the DLMP values are always set by the conventional generators. With 10.1MW of wind, during time-steps 1 – 6, 13 – 15 and 19 – 21 wind is curtailed and therefore sets the DLMP. The DLMPs for bus 1 in the two scenarios are shown in Figure 51. The additional 0.2MW of wind generation makes almost no difference to the DLMP values when demand is higher than 10MW, but reduces them from £47.1/MWh to zero when demand is at 10MW. The addition of the extra 0.2MW of wind capacity reduces the cost of generation by just £50 but the payments by consumers drops by £6050 as the price paid during low demand periods drop to zero. This directly cuts into the generators surplus. During low demand periods, wind is now paid at its marginal cost of production which is zero, and generator surplus for wind is only created at higher demand. In both these scenarios the merchandising surplus is almost zero as there is no congestion on the electrical circuit leaving only a small loss component.

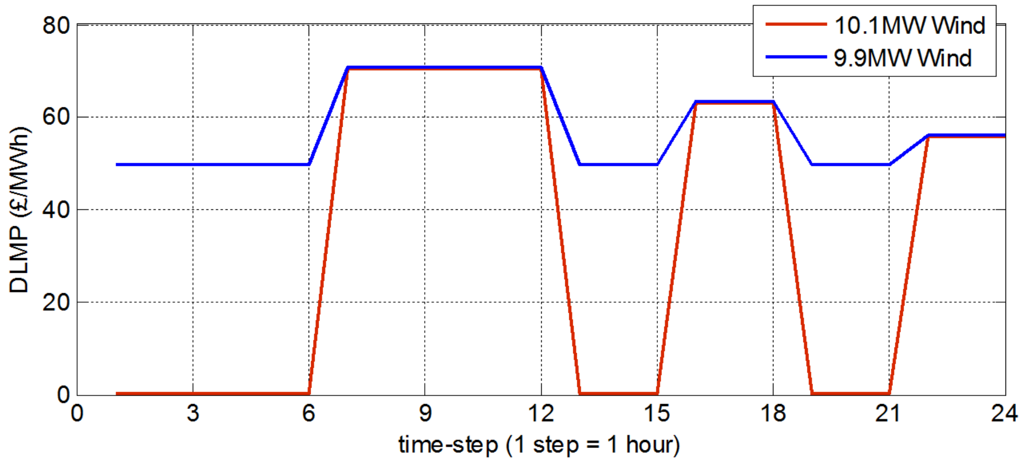

Figure 51: DLMP values for bus 1 with 9.9MW of firm wind compared with 10MW of firm + 0.1MW of non-firm wind.

Table 19: Payments and surpluses for the example case including wind generation with zero marginal cost.

Scenario	Total payments by consumers (£)	Total payments to generators (£)	Total cost of generation (£)	Generator surplus (£)	Merchandising surplus (£)
No Flexible Demand	32,610	29,890	26,060	3830	2,720
5MW wind	30,360	28,820	19,140	9680	1540
9.9MW wind	25,710	25,690	10,520	15,170	20
10.1MW wind	19,660	19,650	10,290	9,400	10

Adding energy storage and flexible demand with non-firm wind generation allows some curtailed wind to be used to meet demand from other time-steps. In the case of energy storage, the demand remains fixed but it may be possible to meet marginal demand at a particular node from curtailed wind generation from a node at a different time-step.

The effect on consumer and generator payments and on generator and merchandising surplus of adding 1MW/6MWh 70% energy storage to a system with 15MW of wind (10MW of which is non-firm) are shown in Table 20. Consumer payments are reduced as the marginal cost of generation is now reduced during high demand time-steps. The results show that in this case, the merchandising surplus increases. Without energy storage, there is a small merchandising surplus due to losses in the electrical circuit. With energy storage the merchandising surplus increases to £430 due to both losses and congestion in the energy storage unit.

Table 20: The effect of adding a 1MW/6MWh 70% energy storage on payments and surpluses with 15MW of wind generation

Scenario	Total payments by consumers (£)	Total payments to generators (£)	Total cost of generation (£)	Generator surplus (£)	Merchandising surplus (£)
15MW wind	18,130	18,120	6,630	11,490	10
+ 1MW store	17,930	17,500	6,210	11,290	430

6.4 Conclusions

This chapter has presented the theory of DLMPs for situations involving intertemporal flexibility. It uses the Lagrangian multipliers on nodal energy balance equations to define a separate node price for each bus and each time-step. The method is an extension of the existing LMP theory – which is new to this thesis – used to define location-specific prices in several major power markets.

The extension allows the effect of energy storage and flexible demand to be directly incorporated into the location- and time-dependant prices. DLMPs are defined as either the marginal cost of supplying the next unit at a particular location and time by using generation anywhere and at any time within the constraints on the network and intertemporal devices.

The method generalises the concepts of both constraint shadow prices and merchandising surplus to DOPF modelling. Dynamic Merchandising Surplus includes the surplus generated by transferring power through energy storage.

A simple case study is used to identify a number of important general conclusions for the theory of DLMP:

- Energy storage reduces the variability in DLMPs as it raises the DLMP at nodes with initially low DLMP and reduces it at nodes with initially high DLMP. The limit of this effect is set by the storage efficiency, and a store will not operate to reduce the ratio of DLMPs between nodes to less than the inverse of the efficiency.
- Flexible demand also reduces variability by increasing initially low DLMPs and decreasing high ones. Flexible demand pays the DLMP at the time of drawing electricity and does not contribute to merchandising surplus.
- The marginal benefit of increasing power and energy capacity of intertemporal devices can be calculated by summing the multipliers on the relevant constraints.
- As DOPF solves a single network spanning an optimisation horizon, DMS is generated when there is a constraint on energy storage capacity, and a loss component due to the efficiency losses in energy storage.
- The existing conclusions for wind in LMP-based systems apply to DLMP systems: wind can displace the most expensive generators, so reducing (D)LMPs. When non-firm wind is present this can reduce the (D)LMP to zero which is the marginal cost of generation for wind.
- Energy storage and flexible demand, by reducing wind curtailment and using this to offset conventional generation, reduce the cost of meeting demand but can also reduce payments by consumers.

The benefit of intertemporal flexibility has been defined so far in terms of its effect on the objective function. This chapter has shown that it is also possible to measure the benefit in terms of the effect on payments by consumers and also on merchandising and generator surpluses. It allows a detailed analysis of the way this flexibility affects the structure of monetary flows between network / market participants.

The chapter has presented this theory in the context of a generic power system rather than specifically to distribution networks. Chapter 7 will apply the DLMP theory to an example ANM scheme being developed on the Shetland Islands. Whilst there are no current plans to use variable pricing on the Shetland scheme, the chapter models developments elsewhere in the world where there is a trend to market-based mechanisms at distribution level. This is shown in the Olympic Peninsula distribution network [6.10] and location-dependent pricing is proposed for the Bornholm distribution network [6.11]. In academic literature the application of LMPs at the distribution level has been studied, for example in [6.4] and in these and similar projects DLMP can be applied to give information on the effect of energy storage and flexible demand in an efficient market.

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Chapter 7: Dynamic Optimal Power Flow on an islanded distribution network

THE SHETLAND ISLANDS are approximately 100 miles off the north coast of mainland UK. They have one of the best wind resources in Europe, and the only operational wind farm on the islands has achieved an annual capacity factor during some years in excess of 0.5. Shetland is both geographically remote and electrically isolated; a core 33kV network supplies power to the majority of Shetland's populated islands. As with many islanded systems, the Shetland power system suffers from low inertia, leading to frequency stability issues which have, in the past, severely limited the capacity of wind generation allowed to connect to the network. For this reason there is only a single 3.66MW wind farm with firm connections and approximately 0.4MW of small scale-renewable generation currently connected.

A project is now underway to increase the capacity of renewable generation connected to the Shetland network and gain the most benefit from that capacity. The Northern Isles New Energy Solutions project (NINES) [7.1] involves the use of an Active Network Management (ANM) scheme and generation curtailment to manage frequency stability as well as thermal and voltage constraints. NINES is a second-generation ANM scheme, as it will also schedule energy storage and flexible demand in advance. In addition, the flexible demand will have the potential to respond to frequency and assist in the management of frequency stability.

This chapter provides a case study based on the NINES project and describes the application and deployment of Dynamic Optimal Power Flow (DOPF) in an industrial project. The objectives of the NINES project are to decrease the energy generation from conventional fossil fuel generators and secondly to reduce the *peak conventional generation* requirement. This second objective has particular benefits because the main power station on Shetland is reaching the end of its operational life and will be replaced in the next few years; management of peak demand can reduce the size of replacement generation plant that will be needed.

This case study concentrates on the first of these objectives and uses DOPF to produce schedules that minimise conventional generation output by using non-firm wind capacity, energy storage and flexible demand – three aspects of the NINES project. As well as applying the DOPF algorithm developed in Chapter 5, this chapter describes the innovation required to produce a bespoke operational model adapted to meet the specific requirements of the Shetland scheme.

Key original concepts and results presented in this chapter are:

- The definition of a *stability envelope* for wind generation that takes account of a broad range of technical and economic stability issues, including frequency stability.
- The scheduling of *frequency-responsive demand* within the DOPF algorithm as a way of managing frequency stability constraints.
- Simulation results show that there is significant benefit from flexible and frequency-responsive demand in terms of reducing conventional generation and little benefit provided by energy storage for this objective.
- The use of Dynamic Locational Marginal Pricing (DLMP) within the Shetland context as a method of defining the benefit of the system in terms of reducing the cost of generation.

In addition it provides an analysis of the first application of DOPF to an industrial project and its role in informing the design of an ANM scheme.

The chapter is structured as follows. In Section 7.1 a description of the Shetland power system is presented, including the current state of the network and the proposed developments under the NINES project.

In Section 7.2 the concept of stability is developed in the context of NINES and more generally as an example of an islanded distribution network.

Section 7.3 gives the full specification of the case study scenarios.

Sections 7.4 – 7 study the problem of scheduling energy storage and flexible demand to gain greatest benefit from wind generation in the Shetland power system under several ANM scenarios. The focus is on scheduling and the calculation of the increased benefit of wind in these scenarios. .

Section 7.8 uses the NINES project to present an example of the application of DLMP using the Shetland power system as an example.

Section 7.9 summarises the learning and discussed how the results produced by DOPF have been used to inform the development of the NINES project itself.

The chapter presents an analysis of a particular configuration of the Shetland systems. As the NINES project is ongoing there are likely to be changes and developments in the project not presented here. In addition, some of the data used in the modelling is either commercially sensitive or represents the outcomes of other academic work that is yet to be published. The work and data presented ensures that the reader is able to replicate the method, and where possible within the project constraints data for an example day is provided in Appendix 3.

In addition, in producing the work presented here the author collaborated with a large research team concentrating on other aspects of the NINES project. These researchers produced the inputs required to run the DOPF models and some of these inputs are described in the chapter. Where work from other researchers is described it is clearly noted[5].

7.1 The Shetland power system

Shetland is home to approximately 22,000 people spread over 16 inhabited islands, all but one[6] of which are connected to the Shetland power system. The electrical demand ranges between 11MW and 47MW, for which a load duration curve is shown in Figure 52. Generation is provided by three main stations and some small-scale generation. The main generation stations are Lerwick Power Station (LPS), a diesel station; Sullom Voe Terminal (SVT) with gas turbines as part of a large oil terminal; and Burradale Wind Farm located near Lerwick. Summary of the power system is given in Table 21.

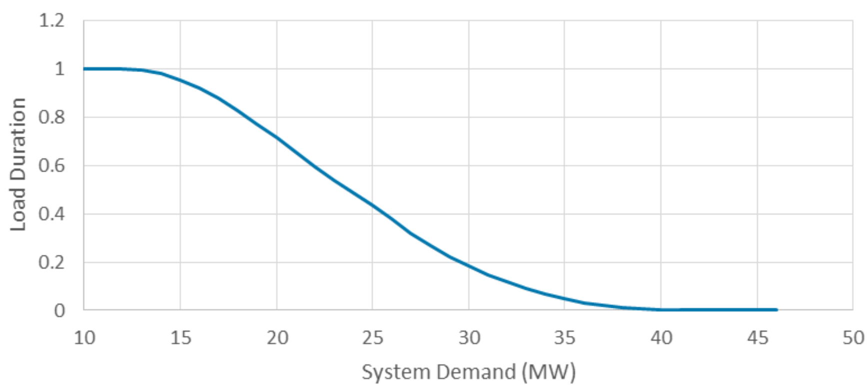


Figure 52: Load duration curve for the Shetland power system.

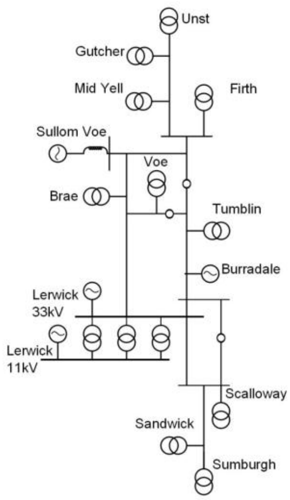
[5] The author would specifically like to acknowledge the following inputs to the DOPF model:
- the concept of the stability envelope was developed by the author, whilst the specific characterisation of each stability rule was the work of the NINES team. The Author would like to acknowledge Michael Dolan (mdolan@smartergridsolutions.com) for this work.
- The demand profiles for flexible demand come from research by the NINES team, the application of those profiles through DOPF is the work of the Author. The Author would like to acknowledge Katalin Svehla (katalin.svehla@strath.ac.uk) and Prof. Joe Clarke for this work.

[6] The island of Foula, with a population of 31, has its own small power system.

Table 21: A summary of the electrical characteristics of the Shetland power system

Component	Parameters	Description
Population	22,000	Of which 7,500 are in Lerwick, the capital.
Electrical demand	11MW – 47MW	Minimum occurred during summer evening, maximum occurred during winter daytimes.
Generation:		
- Lerwick Power Station (LPS)		Diesel generation station at Lerwick with generation capacity capable of meeting all demand on Shetland's islands.
- Sullom Voe Terminal		A large oil terminal with gas-turbine generators. These generators are used to cover all internal demand at the terminal and are contracted to export to the Shetland power system.
- Burradale Wind Farm	3.66MW installed capacity 5 turbines	Located close to Lerwick, Burradale wind farm regularly achieves annual capacity factors above 0.45.
- Small scale wind	0.4MW	Located across the Shetland power system.

(A)



(B)

Figure 53: The Shetland islands: (A) Map of the islands[7] and (B) topological outline of the 33kV power system. This repeats Figure 9.

[7] Shetland map Creative Commons licence courtesy of http://commons.wikimedia.org/wiki/File:Wfm_shetland_map.png

The power system connecting these generators with demand consists of three 33kV circuits radiating out from a hub at Lerwick. The two northern 33kV circuits can be reconfigured by means of normally open points, a procedure which is used in the event of a fault or during maintenance. The geography of Shetland and the 33kV layout are shown in Figure 53. There are a number of other features of the existing Shetland energy system relevant to NINES. These are:

- **Lerwick district heating network:** approximately 1000 premises in the capital town of Lerwick receive heat through the district heating network operated by Shetland Heat Energy And Power (SHEAP). The primary source of heat is the energy recovery plant used to incinerate waste produced both on Shetland and from the surrounding oil and gas industry. This plant produces 6.3MW of heat at a constant rate and this heat is fed into the district heating network; additional heat is currently provided by oil-burning boilers, however SHEAP is currently engaged in a project to provide heat from wind generation via an electric boiler [7.2].
- **Shetland teleswitching scheme for storage heaters:** beyond the district heating network, heat provision on Shetland is through electric heating, solid fuel systems or individual oil tanks. Several thousand households use storage heaters to heat their homes and electric emersion heaters for hot water. The electrical Distribution Network Operator (DNO) operates a teleswitching scheme to spread the electrical demand from these heaters across the day. The scheme works by dividing houses into a number of teleswitching groups and programming heaters to receive switch-on and switch-off instructions relevant to that group via a radio signal. Schedules for delivery of heat to storage heaters are fixed and do not change regularly.
- **Shetland Repowering project:** the current Lerwick power station is nearing the end of its life and will be replaced within the next few years. Planning for the replacement plant is currently underway, and it is expected that the NINES project will influence those plans. In line with the project objectives,

two benefits are identified from NINES: (i) the addition of new wind power provides a benefit in terms of annual energy generation and a corresponding decrease in the annual energy requirements of a new conventional plant; and (ii) through control of energy storage and flexible demand, the ANM scheme can manage the *peak generation requirement* through peak lopping.

- **Viking wind farm:** A project is underway to build a large wind farm on Shetland of 370MW capacity and provide a High Voltage DC link to mainland Scotland with a connection to the main UK transmission network [7.3]. The project has received planning permission but is at a very early stage of development. If the Viking project is successful it will completely change the electrical characteristics of the Shetland Islands. Due to some uncertainties, the work presented in this thesis ignores the Viking project.

7.1.1 Stability on Shetland

For the majority of other distribution networks, the maximum firm wind capacity is defined by thermal or voltage limits and the worst case scenario – usually full generation and low demand. On Shetland the limiting factor is frequency stability. Despite the different limiting factor, the method of defining that firm capacity remains the same: identify the worst case scenario, model this to find the maximum generation allowed in this situation and use this to define the firm capacity limit.

Frequency stability on Shetland is defined as the ability of the system to maintain frequency within nominal limits under the instantaneous loss of all wind generation. Using this definition the *worst case* scenario occurs when there is low inertia, low levels of generation able to respond to frequency variations and when wind generation is at its highest. On Shetland this situation occurs with both low demand and when SVT is offline. Modelling by the DNO has shown that the firm limit is approximately 4MW and this is the capacity of the existing firmly connected wind farm at Burradale and other small scale wind across the network.

7.1.2 The Northern Isles New Energy Solutions project

The NINES project began trial implementation of various innovative solutions during 2012/13 and comprised a number of interconnected components. The overall objective of NINES is to 'trial a set of alternative solutions… to reduce the cost of meeting the electricity needs of Shetland' [7.4]. This can be broken into two components: reducing the fixed capital costs associated with replacing LPS; and secondly reducing operating costs such as fuel by reducing the energy generation required.

As NINES is an ongoing project all aspects are subject to change. The details presented here represents the most up-to-date information the author has available. Whilst the specific quantities are liable to change during development, it is expected that the overall character and objectives of the scheme will remain. As such, the analysis described in this chapter provide an example of the analysis to a Shetland system that can be adjusted to take account of future developments. Below is a brief description of each component of the NINES as planned in January 2013.

7.1.2.1 Non-firm wind capacity

The firm capacity limit discussed above for wind generation is only binding during a few time-steps of the year. Modelling the electrical network with conditions that are not the 'worst case' shows the actual generation limit specific to those conditions. The Shetland ANM scheme will include rules based on the results of this modelling and will allow non-firm wind capacity to generate when doing so will not breach stability limits.

7.1.2.2 Energy storage

A battery energy storage unit is expected be connected to the network at Lerwick. It is expected that this will be a 1MW, 6MWh device and the exact technology to be used is not yet defined.

7.1.2.3 Domestic Demand Side Management of household heating

Some existing electric space and water heating currently controlled by the teleswitching scheme is expected to be re-fitted with new heating devices which have the ability to receive schedules and real-time control signals from the ANM scheme. This forms the Domestic Demand Side Management project (DDSM) – part of NINES. The teleswitching scheme for electric storage and hot-water heating has allowed the DNO to manage the demand peak which threatened to grow after the introduction of storage heaters using off-peak overnight tariffs. However, the level of flexibility provided by the scheme is minimal and cannot be adjusted to the high levels of variability introduced by wind generation.

The DDSM scheme allows daily schedules and real-time adjustment of the electrical delivery of energy by the ANM scheme. In line with the model of flexible demand used in DOPF and presented in Chapter 5, a DDSM device consists of the ability to convert electricity to heat, a heat storage component and an underlying demand profile for heat.

DDSM devices are grouped so that multiple houses can be controlled as one group. The energy storage capacity and power capacity of the group is aggregated from individual devices. Figure 54 shows examples of demand profiles for heat for a group of 100 houses (for space heating and for hot water respectively). The delivery of energy through the electrical system can be varied as long as the underlying heat-demand profile can be met at all times and the state of charge is returned to the initial level at the end of the day.

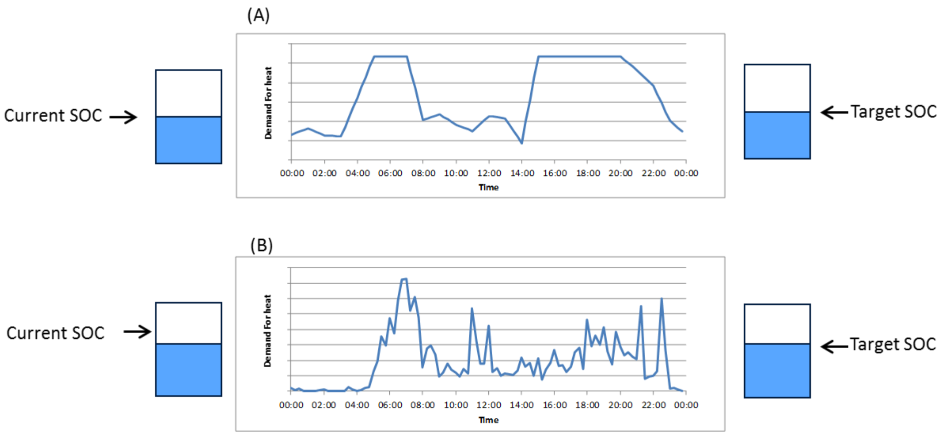


Figure 54: Illustration of demand profiles for (A) space heating and (B) water heating in a group of approximately 100 houses in Lerwick.

Detailed modelling of houses has been carried out and presented as part of the NINES project[8]. The output of this modelling is detailed group demand profiles for each time-step of each day in 2011 including the weather conditions, day of the week and time of the year.

7.1.2.4 Lerwick district heating network wind-to-heat scheme

Approximately 800 households and 200 business in Lerwick – the capital town of Shetland – are connected to the Lerwick district heating network. Heat for this system (6.3MW) comes from a waste incinerator which operates throughout the year. Additional heat is provided from oil-burning boilers.

The operator of the Lerwick district heating network on Shetland currently has a moratorium on the connection of new customers due in part to the lack of renewable heat. In partnership with the NINES project, SHEAP, the district heating system operator, is planning a wind-to-heat system consisting of a wind farm, electric boiler

[8] As with other input data for the NINES project, the raw data was made available as part of the industrial project. This data is commercial sensitivity and is not in the public domain. An example days' worth of data is provided in Appendix 3 to illustrate the format of the data and allow the reader to replicate the method with other data.

and large heat-store. The scheme will both reduce the reliance on oil burning and increase the capacity of the district heating network to meet heat demand from renewable sources. The flow of energy between components of the district heating scheme is shown in Figure 55. Heat from the energy recovery plant is either used directly or stored in the heat tank. Additional wind-to-heat generated in the electric boiler can also be stored and power by the wind farm can also be stored. Remaining wind generation is available to the Shetland power system. Oil boilers will continue to cover any remaining heat demand.

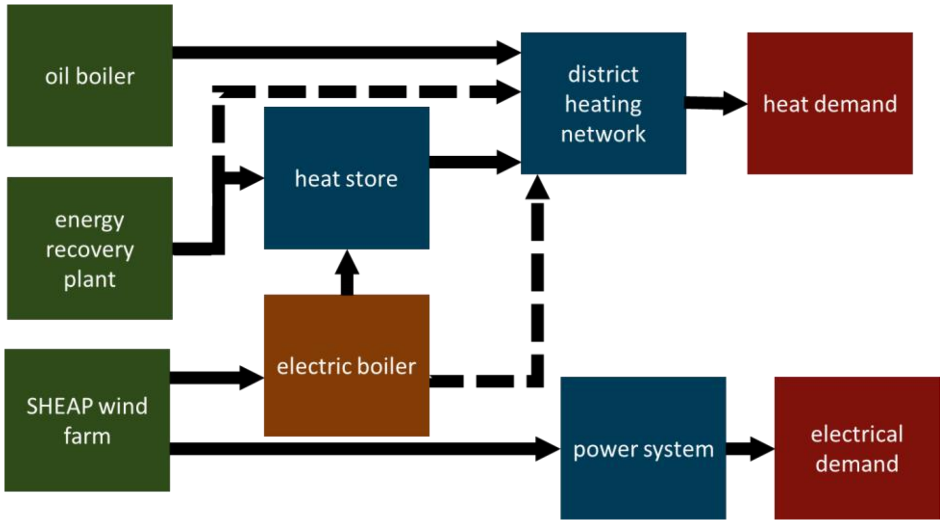


Figure 55: Heat flow from existing and planned components linked to the Lerwick district heating network.

This district heating project provides an interesting and innovative addition to the ANM scheme. However, its detailed analysis and modelling is beyond the scope of this chapter. For more details on the role of wind-to-heat modelling of an islanded power system see [7.5].

7.1.2.5 Frequency-responsive demand

As discussed above, frequency stability is a limiting factor on Shetland. Frequency-response is usually provided by generators providing inertia and through fast-acting governors and generator control systems. The NINES project plans to supplement this with frequency-responsive demand. The project will trial frequency-response on DDSM devices and also potentially on the electric boiler that will form part of the district heating network.

Detailed dynamic modelling of the Shetland network is being carried out to identify the effect of frequency-responsive demand on the dynamics of the Shetland power system, and an explanation of the methodology used is presented in [7.1, 7.6]. The result of this modelling is that for a given generation scenario, the limit on wind generation will be a function of the aggregate demand from frequency-responsive devices. This function can be defined as the *effectiveness* of the frequency-responsive demand. Effectiveness is defined as the additional wind generation allowed per MW of frequency-responsive demand operating at a particular time.

7.1.2.6 The use of Dynamic Optimal Power Flow in the Northern Isles New Energy Solutions project

As part of the NINES project, DOPF has been used in conjunction with other tools to analyse the effect of each of the NINES components on reducing conventional generation output across a given period. As noted above the aim of the project is to reduce the cost of electrical generation, and it is assumed here that variable operating costs are directly proportional to the energy generated by conventional generation.

The discussion from Chapter 4 of the various measures of the benefit of wind generation are relevant here. The NINES project identifies the benefit of wind generation as the reduction in conventional generation. This is similar to the objective developed in Chapter 5 of minimising imports to a transmission-connected distribution network. In this case it minimises conventional generation rather than import.

This chapter provides a case study based on three aspects of the NINES project: non-firm wind capacity, energy storage, and flexible demand (the last is explored both with and without frequency-response). Modelling of the district heating network is not covered. It also concentrates on the second benefit mentioned above: reducing the conventional electricity generation output requirements.

7.2 Defining stability for Shetland

Stability of electrical networks is an important consideration for network planners, and one that is particularly important in small networks. So far in this chapter stability has been discussed in terms of frequency, but as the term 'stability' is generic and can refer to many aspects of power system operation, it is important to define its meaning in a particular context.

The *IEEE/CIGRE Joint Task Force on Stability Terms and Definitions* provide a detailed definition of technical power system security in. From this, they propose a general definition of stability as:

> Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact [7.7].

From this definition the paper identifies three areas of technical stability: rotor-angle, frequency and voltage stability. Operation of all power systems must meet the definition of stability given above with respect to these areas.

This definition of *technical* stability can be extended to include other areas of power system operation such as economic stability. Defining stability in a broader context can also allow for the role of engineering judgement and rules developed heuristically by trial and error, rather than by exhaustive modelling or testing. Whilst the academic engineer tends to prefer theoretically defined rules, heuristic rules form an important part of the operation of real systems. For example, one of the existing operating rules on Shetland places a low bound on the percentage of total generation provided by LPS. This has been develop through experience of operating the network. It ensures sufficient reactive power generation is available from the generator sets at LPS and that in this situation voltage levels are maintained.

Within the NINES project a broad definition of stability is used which encompasses all issues of particular importance to Shetland and goes beyond *technical* stability. Four separate stability aspects have been identified for the Shetland ANM scheme [7.8]:

- **Frequency stability:** the ability of the system to maintain system frequency within nominal limits during a defined set of events. It depends on the system inertia, online-generation, speed of response for generator governors and the time-constant of the current network setup.
- **Spinning reserve stability:** this is closely related to frequency stability, but specifically separates out the *headroom* at the fastest responding generator as a limiting factor. The consequence of having too little spinning reserve is that if wind generation is lost, the remaining generation will attempt to respond and could potentially trip its protection or that of a network component connecting it to the network as it exceeds its own headroom to respond.
- **Dispatch stability:** as with spinning reserve stability, this is closely linked to frequency stability. It isolates the issue that the current on-line generation will have a minimum allowed output. For example, generators may be subject to minimum limits due to technical operation or emissions criteria related to part-load efficiencies.
- **Operational stability:** this term is used to define wider stability issues. For example there may be contractual obligations on maximum and minimum outputs from specific generators, or heuristic decisions developed through engineering experience of operating a particular power system.

Frequency, spinning-reserve and dispatch stability for a small islanded network effectively come under the definition of short-term frequency stability as defined in [7.7]. Operational stability issues are beyond the scope of the work presented in [7.7] in that they represent a combination of non-technical and heuristic operating rules and conditions specific to a particular system.

The extent to which these considerations affect network operation depends on events happening against which the system operator wishes to secure the network. It is the responsibility of the network operator to maintain the supply of electricity, however in a relatively small islanded network it would be impossible to secure the system against a fault on a multi-MW generator without temporarily disconnecting some customers. Most power systems make use of underfrequency load shedding as a method of saving the network from collapse in the case of a significant fault, and the stability of a network with non-firm wind capacity should be judged by the same standard. Wind generation introduces variability, and an ANM scheme should ensure that the additional variability does not adversely affect the reliability of the network.

Additional wind generation in an islanded network introduces variability for two reasons:

- Wind generation is intermittent, it has the potential to vary the overall output by a significant fraction of the installed capacity over a period of tens of seconds. A power system with a high penetration of wind must be able to cope with this variation, and in a small geographical area, such as a small, islanded power system, all wind generation may be affected by the same variations in wind at roughly the same time.
- As with distributed generation, wind on an islanded network is subject to protection settings which are likely to disconnect that generation in the event of a voltage and frequency deviation. On an islanded network these deviations may occur more regularly and be experienced by generation more severely than on a large power system.

Once the events to secure against have been defined, detailed dynamic modelling can be used to identify a limit for wind generation for each separate set of operating conditions. The results from these studies for multiple simulations can be combined to produce a rule linking measureable quantities from the power system with maximum defined outputs from wind generation.

7.2.1 Defining and maintaining stability in Active Network Management

When using an ANM scheme to manage stability it is important that it is defined in such a way that allows logical rules to be applied based on measurement of the system and a well-defined control approach and enabling architecture. Existing ANM schemes use simple linear rules to determine the limit on generation due to thermal and voltage limits. On Orkney such rules take the form of measurements of power flow combined with predefined operating margins: once power flow along a line reaches the operating margin and is approaching the maximum power flow, trimming and tripping actions are triggered at the non-firm generators associated with that constraint [7.9].

A design requirement for the Shetland ANM scheme is that linear relationships are defined between the output of monitored Shetland generators and the maximum wind generation [7.6]. Margins may be applied to the theoretical limit and once the limits are reached, trim and trip commands will be sent to the generators.

Limits on each of the stability considerations discussed above together define a *stable envelope for wind generation*, within which operation must be maintained. Figure 56 illustrates the concept of the stability envelope for a system where network, frequency and spinning reserve constraints form the limits on wind generation. This represents the Shetland case. Where stability limits for other systems take different values, the shape of the stability envelope will change, however the concept remains unchanged. In this case network limits are fixed at all times, and frequency and spinning reserve limits depend on the current dispatch of generation. Figure 56 also shows the concept of *operating margin* in which the maximum allowed wind generation is further constrained within the envelope. The exact size of the operating margin will depend on the maximum expected rate of change of demand and wind generation under normal operating conditions and also on the approach to risk (perhaps informed and developed by analysis and experience) adopted by the system operator.

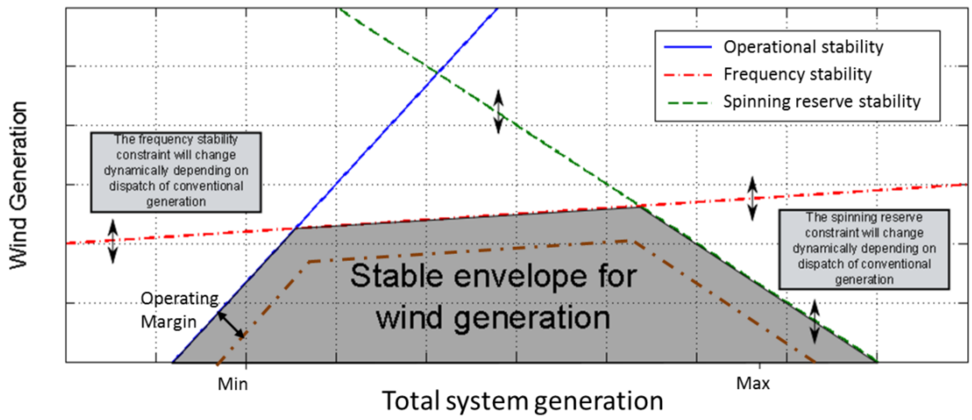


Figure 56: The concept of the stable operating envelope as defined by stability limits. The operating margin is configurable, and both the frequency and spinning reserve constraints depend on which conventional units are dispatched.

The stable envelope for wind generation acts as the limits within which the ANM scheme must maintain output of firm and non-firm wind capacity. As with the thermal and voltage limits already discussed, curtailment is applied based on a principle-of-access. In the case of Shetland this is a priority order 'last-in-first-out' (LIFO) scheme similar to that used on Orkney [7.10].

The Shetland ANM scheme will be a *second-generation ANM scheme* as discussed in Chapter 2. It is second-generation as it must move beyond the 'real-time monitor and control' paradigm and engage in scheduling of energy storage and flexible demand in advance of operation. The components required for such an ANM control system are shown in Figure 57. First-generation ANM schemes such as the existing Orkney scheme use the *automatic real-time monitor and control* box and also allow manual intervention. The addition of energy storage and flexible demand gives the opportunity to create a schedule for that flexibility. The role of DOPF simulations in the NINES ANM project is to inform the design of the scheduling engine.

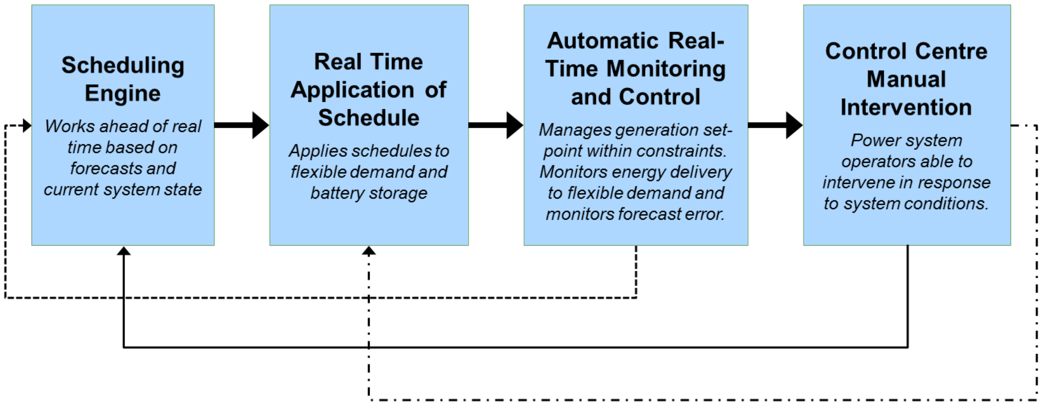


Figure 57: Summary of the roles of the Shetland ANM scheme as an example of a second-generation system (taken from [7.11])

7.2.2 Defining stability rules in Dynamic Optimal Power Flow

Extending the DOPF of Chapter 5 to include stability limits can be achieved by adding linear constraints linking the outputs of various generators and frequency-responsive components. A generic linear stability rule relating the outputs of: conventional generators; firm and non-firm wind generators; and frequency-responsive demand components can be given in the form:

$$\sum_{n=1}^{n_{firm}} \alpha_n P_{firm,n} + \sum_{m=1}^{n_{nf}} \beta_m P_{nf,m} + \sum_{p=1}^{n_{conv}} \gamma_p P_{conv,p} + \sum_{q=1}^{n_{frd}} \delta_p P_{frd,q} > \varepsilon \qquad (7.1)$$

All of $\alpha, \beta, \gamma, \delta$ and ε are sets of constant coefficients, relating to $P_{firm,n}$, $P_{nf,m}$, $P_{conv,p}$, $P_{frd,q}$, the sets of power from firm wind generators, non-firm wind generators, conventional generators, and frequency-responsive demand units respectively . This generic form can be used to model a range of different categories of limits. Three particular categories are relevant to the Shetland case study are discussed.

Minimum fraction of output from one generator

If the output of one conventional generator, $P_{conv,i}$, must be greater than a given fraction, ρ, of total generation, P_g^{total}:

$$P_{conv,i} > \rho P_g^{total} \tag{7.2}$$

Expanding P_g^{total} in terms of individual generators:

$$P_i > \rho \left\{ \sum_{n=1}^{n_{firm}} P_{firm,n} + \sum_{m=1}^{n_{nf}} P_{nf,m} \sum_{p=1}^{n_{conv}} P_{conv,p} \right\} \tag{7.3}$$

and noting that $P_i \in P_{conv}$ and without loss of generality define this as conventional generator 1. In the generic format of (7.1) this becomes:

$$\sum_{n=1}^{n_{firm}} -\rho P_{firm,n} + \sum_{m=1}^{n_{nf}} -\rho P_{nf,m} + P_{conv,1} + \sum_{p=2}^{n_{conv}} -\rho P_{conv,p} > 0 \tag{7.4}$$

As frequency-responsive demand is not involved in this constraint, all $\delta$are set to 0.

Wind generation bounded by linear function of total generation

If the maximum limit of wind generation is set by a linear bound in the form:

$$aP^{total} + b > P^{wind} \tag{7.5}$$

where P^{wind} is the total wind generation including both firm and non-firm generation. Then expanding P^{total} and P^{wind} and rearranging to give the constraints in the generic form of (7.1) gives:

$$\sum_{n=1}^{n_{firm}} (\mathrm{a}-1)P_{firm,n} + \sum_{m=1}^{n_{nf}} (\mathrm{a}-1)P_{nf,m} + \sum_{p=1}^{n_{conv}} \mathrm{a}P_{conv,p} > -b \tag{7.7}$$

If the effect of frequency-responsive demand is to be included, an additional term representing the effect of that independently should be added:

$$\sum_{n=1}^{n_{firm}} (\mathrm{a}-1)P_{firm,n} + \sum_{m=1}^{n_{nf}} (\mathrm{a}-1)P_{nf,m} + \sum_{p=1}^{n_{conv}} \mathrm{a}P_{conv,p} + \sum_{q=1}^{n_{frd}} \delta P_{frd,q} > -b \tag{7.8}$$

Where δ is the effectiveness of frequency-responsive demand (defined in Section 7.1.2 above) and is assumed to be the same for all frequency-responsive units.

Wind bounded by spinning reserve

This defines a limit on wind generation as being no more than the maximum headroom available at a particular generator, in this case conventional generator *I,* representing the fastest responding generator. In this situation additional spinning reserve can be provided by frequency-responsive demand:

$$P_{conv,i}^{max} - P_{conv,i} > P_{wind} - P_{frd} \tag{7.9}$$

Again expanding and rearranging gives:

$$-\sum_{n=1}^{n_{firm}} P_{firm,n} - \sum_{m=1}^{n_{nf}} P_{nf,m} - P_{conv,i} + \sum_{q=1}^{n_{frd}} P_{frd,q} > -P_{conv,i}^{max} \tag{7.10}$$

And the coefficients, γ_p, on all other conventional generators are 0 as the slow response does not allow them to contribute to spinning reserve before generation i reaches its full output and is in danger of tripping generator and network protection.

Inequalities (7.4), (7.8) and (7.10) are added to the DOPF formulation of Chapter 5. The formulation used in this case study is summarised in Appendix 1.

7.3 NINES: the case study defined

The case study presented in this thesis is a subset of the developments proposed under the NINES project. It includes the following components:

- Generation curtailment (non-firm wind capacity in a LIFO scheme)
- Energy storage
- Flexible DDSM
- Frequency-responsive DDSM

The case study does not include the wind-to-heat district heat network.

The objective of the case study is to provide an example of the method of analysis used in the NINES project and to provide realistic results. However, to maintain commercial confidentiality, the actual quantities used here are not exactly those planned on Shetland. For example, coefficients of the stability limits, contractual arrangements and locations of new developments have been changed. As such the reader should consider the results presented here as representative of the results from the NINES project.

7.3.1 Objective

The objective of NINES project studied here is to **minimise generation from conventional sources:**

$$f = \min \sum_{t=1}^{t_n} \{P_{LPS}(t) + P_{SVT}(t)\} \tag{7.11}$$

where $P_{LPS}(t)$ and $P_{SVT}(t)$ are the are the power generated by LPS and SVT respectively. In relation to Chapter 4, this corresponds to defining the benefit of wind generation by its ability to offset conventional generation. In previous chapters this was achieved by minimising import to the network from a transmission network. In the island-network context of this chapter it is more directly achieved by minimising output from the two conventional generators. SVT is modelled with lower costs than LPS, and generation from SVT is therefore used in priority over LPS, within thermal, voltage and stability constraints.

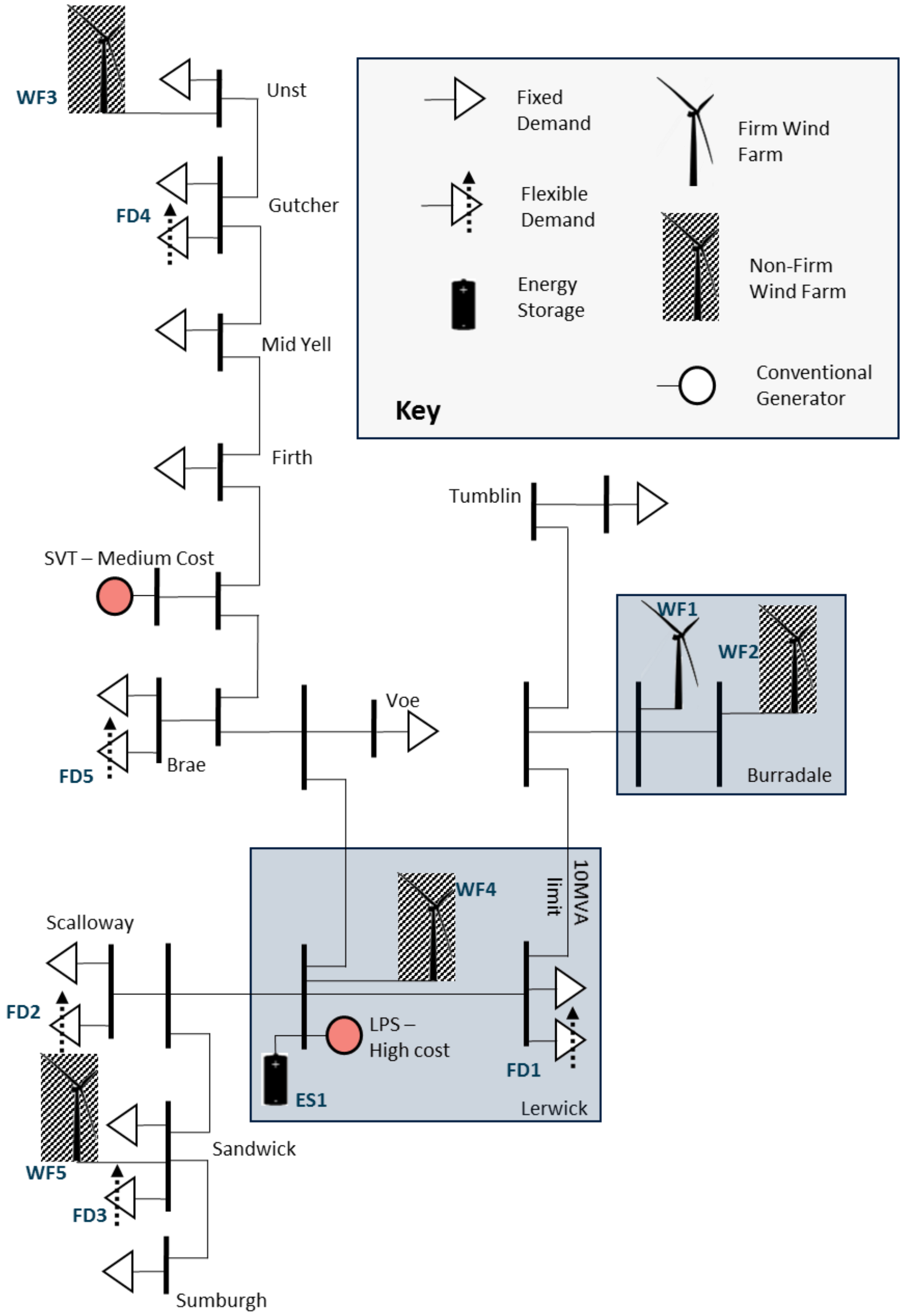


Figure 58: Network diagram of Shetland power system showing flexible components modelled in this chapter. Wind Farm 1 (WF1) is a 4MW firm wind farm, WF2 – WF4 are non-firm wind farms and the capacity is varied across simulation cases. There are 5 flexible demand (FD) components and 1 energy storage (ES) unit.

7.3.2 Network model

A simplified network diagram is shown in Figure 58 which shows the location of the key components. Firm-connected wind generation of 4MW capacity is installed at Burradale, and 4 non-firm wind farm locations are identified. There are 5 locations for flexible demand and 1 energy storage unit. Note that the thermal limit for the line linking Burradale and Lerwick is reduced from the actual value to 10MVA in this case study. This gives a constraint on the output of WF3 required to maintain thermal limits to make the case study illustrative of management of PF limits.

The outline 33kV network was provided by the distribution network operator as a PSS/E model and converted to Matpower. The model contains 26 buses and 25 branches. Existing generation is from 3 generation stations: LPS, SVT and Burradale. Burradale capacity has been increased from 3.66MW to 4MW to include in the single model the existing small-wind capacity. Power Flow analysis performed in the NINES project and confirmed with the DNO shows that voltage is well managed by current operating procedures and reactive generation on Shetland.

7.3.3 Wind power model

A wind generation output time-series is taken directly from records for Burradale generation for the period January 2011 – December 2011. During the year Burradale achieved a capacity factor of 0.49. To ensure that this data is representative of the available wind resource, periods in which one or more turbines were out of action have been identified. Generation during these periods is scaled to give a value equivalent to all turbines being in service.

For the purposes of this case study are all wind farms on Shetland are assumed to experience the same wind regime and, as such, available generation is perfectly correlated.

7.3.4 Demand model

Demand is estimated by summing historical records of generation. The output of all generators on Shetland are summed to give a total generation for each point in time. In addition the network model provided by the DNO includes peak demand values at each bus and it is assumed that demand at any time is split between these buses in line with the ratio of demand peaks. Power flow studies are used to identify the network losses for different levels of total generation and these losses are subtracted from the total system generation to give the estimated of historic demand.

Periods when the network was in a fault condition, and therefore demand was disconnected have been identified. Where faults are for 2 time-steps or less (30 minutes) then demand in those two time-steps is set equal to the previous / next time-step. For longer faults, data is replaced by a copy of the demand data from the previous day.

7.3.5 Active Network Management model

The ANM scheme is assumed to perform perfectly its role in maintaining thermal, voltage and stability limits. The non-firm wind capacity shown in Figure 58 is modelled with priority-order principle-of-access between individual generation stations as defined by equation (5.12) of Chapter 5. The modified objective used to incorporate the priority order is:

$$f_{modified} = \sum_{t=1}^{t_n} \left\{ \{P_{LPS}(t) + P_{SVT}(t)\} + \sum_{nf=1}^{nf_n} \frac{p}{1000} P_{nf}(t) \right\} \tag{7.12}$$

The specifics of the energy storage and flexible demand aspects are introduced below. When included, the ANM scheme scheduled these devices for the coming 24-hour period. It is assumed for the majority of the studies that the ANM scheme has perfect foresight of wind generation and demand for the coming 24 hours.

7.3.6 Network stability model

Three stability rules together define the stable envelope of wind generation. These are:

1. Operational stability rule[9]:
    a. Output of SVT must be at least 3.6MW at all times
    b. Output of LPS must be at least 20% of total generation for the island

Combining these two limits gives the following inequality:

$$0.8P_{total} - 3.6 > P_{wind} \tag{7.13}$$

2. Frequency stability rule:

    The limit on wind from a frequency stability perspective is defined as:

$$0.44P_{total} + 3.1 > P_{wind} \tag{7.14}$$

3. Spinning reserve stability rule:

    SVT is assumed to provide spinning reserve, and its output is constrained to a maximum of 25MW:

$$25 - P_{SVT} > P_{wind} \tag{7.15}$$

The three rules (7.13) – (7.15) can be rearranged into the form of inequality (7.1), and the envelope defined by them is shown in Figure 59. This formulation of the rules is included with an overview of the full DOPF formulation used for the case study in Appendix 1.

[9] The values used here do not represent the actual arrangements of the current or future Shetland networks. They are representative of realistic rules.

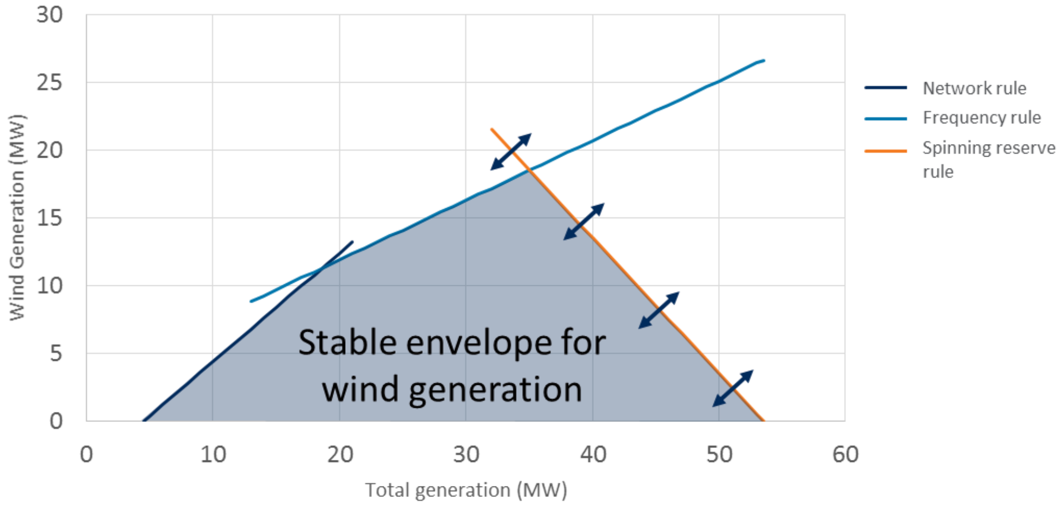


Figure 59: The stable wind generation envelope for the Shetland case study with no flexible demand. The Spinning Reserve rule moves depending on the current dispatch of SVT, and the maximum wind it can allow is 21.4MW, which corresponds to the minimum dispatch of SVT.

7.3.7 Other network components

Energy storage, DDSM, wind-to-heat and frequency-responsive demand are studied in Sections 7.5 - 7.6.4. The specifics of these are introduced in the relevant sections.

7.3.8 Time-steps and time-horizon

A DOPF optimisation is run for each 24-hour period of the year 2011. Each day is divided into 96 time-steps, each of 15 minutes duration. Generation and demand values for each time-step represent an average value for those 15 minutes. Each 24-hour optimisation represents a day-ahead scheduling problem for the NINES system.

7.3.9 Case study questions

The DOPF method is used to analyse this case study and specifically to answer the following questions:

1. What is the capacity factor and annual generation of each MW of wind generation connected under the scheme?

2. What capacity of wind generation can achieve a capacity factor in excess of 0.25 when curtailment is applied[10]? How does the addition of energy storage, flexible demand and frequency-responsive demand affect the capacity factor?
3. What is the reduction in conventional generation that optimal operation of energy storage and flexible demand creates?

7.4 The benefit of non-firm wind capacity

This section presents results with non-firm wind generators controlled by ANM and curtailed to maintain the power system within limits. It shows the benefit of non-firm wind capacity in offsetting conventional generation without the addition of flexible technologies. The results are based on the following scenario: four wind farms have applied for a non-firm network connection on Shetland under the NINES scheme, with a combined capacity of 26MW. The *principle-of-access* for these is priority order in the form of LIFO. The planned capacities of these wind farms and their priority order are shown in Table 22. It is unlikely that all of the planned capacity will be economically viable. Non-firm wind capacity is defined as *economically viable* if it has a marginal capacity factor of 0.25 or greater.

For these studies the DOPF algorithm is run with no flexible devices and the algorithm simply minimises conventional generation by maximising wind generation. Curtailment is applied to maintain both the thermal limit between Burradale and Lerwick (see Figure 58) and the network stability limits, and the order of curtailment follows the priority order given in Table 22.

[10] A capacity factor of 0.25 is used as the definition of economically viable for a non-firm wind farm as discussed in Chapter 5.

Table 22: Example of 'planned' capacities of wind farms for the Shetland case study. For locations refer to the network diagram in Figure *58*, above.

Wind Farm	Location	Planned Capacity	LIFO priority
WF2	Burradale	8MW	1
WF3	Lerwick	6MW	2
WF4	Mid Yell	5MW	3
WF5	Sandwick	7MW	4

If no curtailment is applied, each 1MW of installed capacity generates 4.28GWh during the year, corresponding to a capacity factor of 0.49. The exact reduction in conventional generation is a combination of this additional wind generation and changes in network losses.

Studies are run for non-firm wind capacities ranging from 1MW to 26MW increasing at 1MW steps. Non-firm generation is connected according to the priority order, so initially each MW of additional generation is added at WF2, and when this reaches its full capacity of 8MW, additional generation is added at WF3. The process continues up to a limit of 26MW of non-firm capacity.

Table 23 shows the results of studies with non-firm wind capacity. Listed are the: generation and curtailment at each wind farm; capacity factors of each wind farm and the entire fleet; and conventional generation. The additional energy generated by each MW of non-firm wind generation (the marginal benefit of capacity when measured in wind energy generated) is plotted in Figure 60. Initially curtailment is almost zero and each MW of non-firm wind generates 4.28GWh per year. When the capacity of WF2 reaches 7MW, during times of full wind output the thermal limit on the line linking Burradale to Lerwick becomes active. Output of WF2 is curtailed to maintain is the thermal limit. This creates the characteristic dip in Figure 60 at 7 – 8MW. From 9MW of total non-firm generation capacity and upwards, no more generation is placed behind the thermal constraints and the marginal benefit rises

Table 23: Results for non-firm wind generation for base case simulations with no flexible demand or energy storage

Total NF capacity (MW)	*Capacity at each Wind Farm (MW)*				*Generation at each wind farm (GWh)*				*l Gener-ation (GWh)*	*Curtailment at Each wind Farm (GWh)*				*Curtai-lment (GWh)*	*Generation at conventional stations (GWh)*		*Gene-ration (GWh)*
	WF2	WF3	WF4	WF5	WF2	WF3	WF4	WF5	Total	WF2	WF3	WF4	WF5	Total	SVT	LPS	Total
0															59.57	147.53	207.10
1	1				4.28				4.28	0.00				0.00	57.71	144.80	202.50
2	2				8.56				8.56	0.00				0.00	56.35	141.49	197.84
3	3				12.84				12.84	0.00				0.00	55.49	137.65	193.14
4	4				17.12				17.12	0.00				0.00	54.87	133.56	188.44
5	5				21.39				21.39	0.01				0.01	54.39	129.38	183.77
6	6				25.64				25.64	0.04				0.04	53.99	125.17	179.16
7	7				29.58				29.58	0.37				0.37	53.66	121.26	174.91
8	8				31.89				31.89	2.34				2.34	53.41	119.01	172.42
9	8	1			31.89	4.13			36.02	2.34	0.15			2.49	53.34	114.81	168.15
10	8	2			31.89	8.10			40.00	2.34	0.46			2.80	53.31	110.84	164.15
11	8	3			31.90	11.80			43.70	2.34	1.03			3.38	53.33	107.20	160.53
12	8	4			31.91	15.16			47.07	2.34	1.95			4.30	53.38	103.94	157.31
13	8	5			31.91	18.15			50.06	2.34	3.25			5.59	53.46	101.06	154.52
14	8	6			31.92	20.54			52.46	2.34	5.43			7.77	53.57	98.57	152.15
15	8	6	1		31.91	20.54	2.37		54.82	2.34	5.43	1.91		9.68	53.28	96.39	149.67
16	8	6	2		31.91	20.54	4.39		56.85	2.34	5.43	4.17		11.93	53.02	94.57	147.59
17	8	6	3		31.91	20.54	6.06		58.51	2.34	5.43	6.78		14.55	52.80	93.07	145.86
18	8	6	4		31.91	20.54	7.34		59.79	2.34	5.43	9.77		17.54	52.63	91.83	144.46
19	8	6	5		31.91	20.54	8.44		60.89	2.34	5.43	12.96		20.73	52.49	90.77	143.26
20	8	6	5	1	31.91	20.54	8.44	0.97	61.86	2.34	5.43	12.96	3.31	24.04	52.34	89.82	142.17
21	8	6	5	2	31.91	20.54	8.44	1.85	62.74	2.34	5.43	12.96	6.71	27.44	52.22	88.96	141.18
22	8	6	5	3	31.91	20.54	8.44	2.66	63.54	2.34	5.43	12.96	10.18	30.91	52.10	88.17	140.27
23	8	6	5	4	31.91	20.54	8.44	3.40	64.29	2.34	5.43	12.96	13.71	34.44	52.00	87.45	139.44
24	8	6	5	5	31.91	20.54	8.44	4.10	64.99	2.34	5.43	12.96	17.29	38.02	51.90	86.77	138.67
25	8	6	5	6	31.91	20.54	8.44	4.75	65.64	2.34	5.43	12.96	20.92	41.65	51.81	86.14	137.95
26	8	6	5	7	31.91	20.54	8.44	5.36	66.25	2.34	5.43	12.96	24.59	45.32	51.73	85.55	137.28

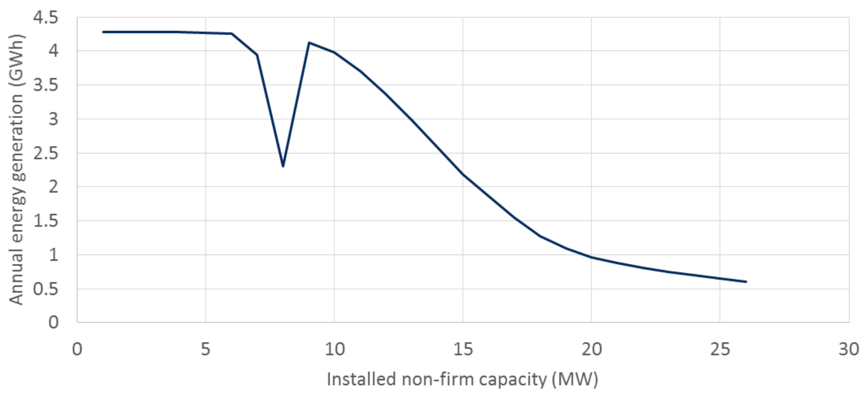


Figure 60: The benefit of each additional MW of non-firm wind capacity in terms of the energy it generates during a 1-year period. Note the obvious drop in benefit at 7 – 8MW due to the thermal constraint on WF2 from the line between Burradale and Lerwick.

again; but the stability limits become binding as more capacity is added and with higher capacity the marginal benefit decreases.

As mentioned throughout this thesis, the objective of ANM schemes is not the generation of electricity from wind, but the *effect* of that additional wind generation. In the case of NINES the objective is to reduce conventional generation. The benefit of WF2 in terms of reducing conventional generation is 34.68GWh, at an average of 4.33GWh per MW of installed non-firm wind capacity. This benefit is greater than the energy generated by that wind farm, as the additional wind generation leads to a reduction of network losses. The benefit of all 26MW of non-firm wind capacity is a reduction of 69.82GWh conventional generation or 2.68GWh/MW installed non-firm wind capacity. At 26MW the average capacity factor of all non-firm wind capacity is 0.29, however the viability of each 1MW of installed capacity is defined by its *marginal* capacity factor. Table 24 shows the benefit of each additional MW of non-firm generation capacity in terms of the reduction in conventional generation and the marginal capacity fact of that MW. The marginal capacity factor of each MW is estimated by calculating the additional wind generation of the fleet when the capacity is increased by 1 MW. The middle column of Table 24 shows the marginal decrease in conventional generation and the right hand column gives the marginal capacity factor. Taking a marginal capacity factor of 0.25 as a measure of viability, 15MW of non-firm wind capacity is viable in this scenario; the marginal benefit of the 15th MW is a 2.47GWh/MW reduction in conventional generation. From **Table 23** it can be seen that the total benefit of 15MW non-firm wind is 57.43GWh. The additional planned capacity listed in is Table 22 is not economically viable and is unlikely to be developed.

Table 24: Marginal conventional generation reduction and marginal capacity factor of each 1MW of non-firm wind capacity added to the NINES network.

Total NF capacity (MW)	*Marginal conventional decrease (GWh/MW)*	*Marginal non-firm wind capacity factor*
1	4.60	0.489
2	4.66	0.488
3	4.71	0.488
4	4.70	0.488
5	4.67	0.488
6	4.61	0.485
7	4.25	0.451
8	2.50	0.263
9	4.27	0.472
10	4.00	0.454
11	3.62	0.423
12	3.21	0.384
13	2.80	0.341
14	2.37	0.294
15	2.47	0.250
16	2.08	0.212
17	1.72	0.176
18	1.41	0.146
19	1.20	0.125
20	1.09	0.110
21	0.99	0.100
22	0.91	0.092
23	0.83	0.085
24	0.77	0.080
25	0.72	0.075
26	0.67	0.069

The addition of non-firm wind capacity does not simply reduce conventional generation by an amount corresponding to its generation. Network losses are also reduced. The difference between non-firm wind capacity and conventional reduction can be seen in the results of Table 23. With zero non-firm wind capacity connected, conventional generation provides 207GWh. Network losses are 9.44GWh, which is 4.2% of total generation. At 15MW non-firm wind capacity, losses have dropped to 6.84GWh or 3.1% of total generation.

A plot of the decrease in losses as non-firm wind capacity increases is shown in Figure 61. The decrease in losses is not a simple function of installed wind but depends on both the total capacity and the location at which wind generation is added.

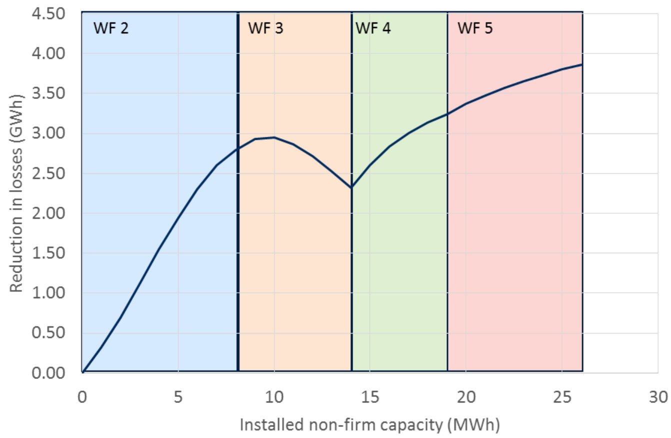


Figure 61: Reduction in losses with installed non-firm wind capacity. The shaded boxes highlight the location of marginal capacity.

Initially wind generation is added at Burradale (WF2) and this tends to displace generation at SVT which in turn tends to reduce the flow of power from SVT to the load-centre at Lerwick. Reducing the high power flow on this line has a large effect on systems losses.

The second non-firm wind farm (WF3) is located at Unst. A small capacity of wind generation here feeds demand at Unst and Gutcher. This reduces power flow from SVT northwards. However, there are only small peak demands at these buses: Unst has a peak demand of 1.6MW and Gutcher 0.9MW - and at higher non-firm wind capacities (at WF3) there is an increase in the export of wind generation southwards, leading to a rise in losses.

The addition of capacity at WF 4 and WF5 tend again to reduce power flow from SVT to Lerwick and therefore continue the reduction of power flow and losses.

7.4.1 Analysing the schedule: 12th June 2011

The wind generation available and scheduled across the 96 time-steps of 12th June is shown in Figure 62. The stability rules refer to limits on total wind generation – firm and non-firm, and as such the schedule illustrated includes both the 4MW firm and 15MW non-firm connected wind capacity discussed. Curtailment occurs from approximately 02:00 to 17:00. At other times of the day there is less wind available and no curtailment.

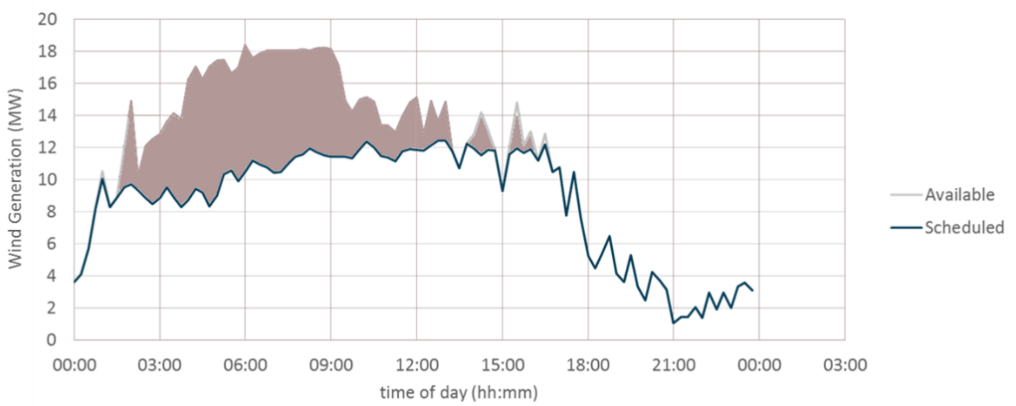


Figure 62: Available and scheduled non-firm wind generation for 12th June 2011. Curtailed generation output is shaded.

The time-series data of Figure 62 can be represented as a scatter plot of total system generation against total wind generation. This is shown in Figure 63 and is plotted on top of the stability envelope from Figure 59. The small red dots represent the scheduled wind; the larger grey dots show the same situation without curtailment of non-firm wind capacity.

The action of the ANM scheme modelled by the DOPF is to curtail the generation until those 57 points fall on the stability limit. This is shown by the arrows linking available wind generation points with scheduled wind generation points. Points already within the stability envelope remain unchanged.

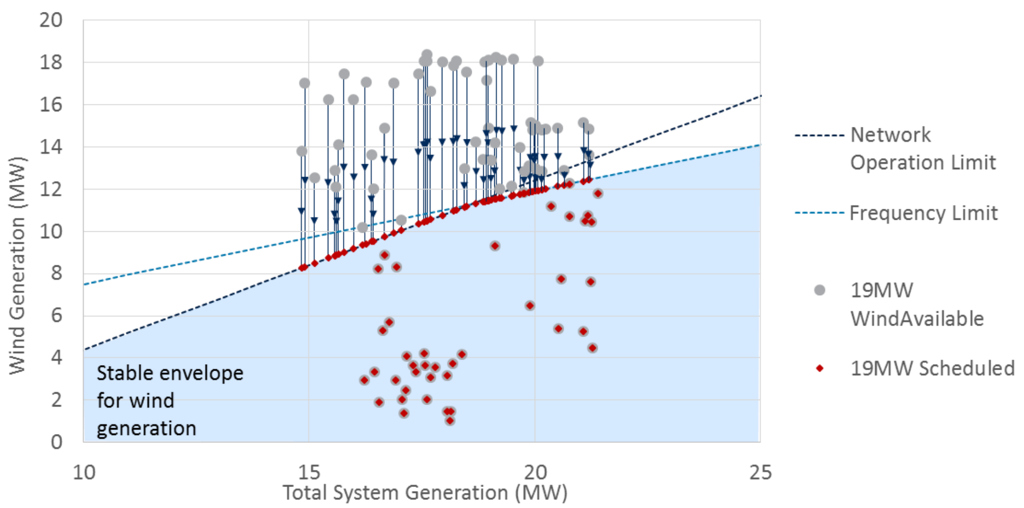


Figure 63: Results showing the wind generation (both available and scheduled) and system generation at each of the 96 time-steps of 12th June 2011. These data points overlay the network and frequency limits and shows part of the stable envelope (highlighted).

7.4.2 Base case summary

In summary, a generation curtailment scheme with 15MW of non-firm wind capacity is likely to be economically viable under this Shetland scenario: 8MW at Burradale; 6 MW on Unst and 1MW at Lerwick. This offsets 57.43GWh of conventional generation output, a reduction of 28% compared with the current situation. The average reduction in conventional generation per MW of non-firm wind capacity is 3.82GWh/MW and the marginal benefit at 15MW non-firm wind capacity is 2.48GWh/MW.

7.5 The benefit of energy storage

An energy storage unit is planned for the Shetland network as part of the NINES project and will be located at Lerwick. This will be owned and operated by the DNO and is a resource to meet the network objectives, namely minimising the requirement for conventional generation (capacity and output).

Energy storage is studied with the 15MW of non-firm wind capacity already shown to be viable. The scenarios presented here answer question 1 and 3 from Section 7.3: how energy storage affects the generation of non-firm wind capacity and its ability to offset conventional generation.

A 1MW, 6MWh, 77% efficient store is added to the base-network at Lerwick as shown in Figure 58. This represents the size of battery planned for Shetland [7.4] and an estimate of the round trip efficiency of a Sodium Sulphur battery [7.12, 7.13]. An optimisation is run for each day of 2011 and results compared to the 15MW scenario without energy storage. The results for non-firm wind capacity and conventional generation with and without storage are shown in Table 25. The addition of this energy storage allows an increase in wind generation of 487MWh and a corresponding decrease in conventional generation of 290MWh. These values represent a 0.9% increase in non-firm wind generation output and only a 0.2% decrease in conventional generation output.

Table 25: The effect of a 1MW/6MWh 77% efficient store on wind and conventional generation

	Generation at each wind farm (GWh)				*Total Generation (GWh)*		*Conventional Generation (GWh)*
No Energy Storage	31.914	20.540	2.369		54.822		149.676
With Energy Storage	31.914	20.930	2.410		55.254		149.366
				Increase:	0.432	Decrease:	0.310

Whilst these results are modest it is important to benchmark the effect by the size of the store. In Chapters 5 and 6 the effect of energy storage was benchmarked by the maximum charge and discharge achievable from a store could achieve across the study period taking account of efficiencies. For the store analysed here over a one year period it is possible to charge a total of 4.30GWh and discharge 3.37GWh after losses. These can be used to benchmark the actual increase in renewable generation and decrease in conventional generation.

Table 26 shows such a calculation for the NINES energy store, the difference between maximum charge and discharge is due to the storage efficiency losses.

Table 26: Benchmarking the benefits of energy storage

	Maximum charge / discharge across one year (GWh)	Wind generation increase (GWh)	Conventional generation decrease (GWh)	Normalised effect on wind / conventional generation
Charging	4.38	0.487	N/A	0.11
Discharging	3.372	N/A	0.290	0.086

The effectiveness of energy storage at increasing wind generation and decreasing conventional generation relies on how often curtailment occurs, on the changes in network losses and the interaction of generation with the stability rules.

In the scenario studied, there is no curtailment during 85% of all time-steps, including 42 full days with zero curtailment. In effect, this limits the annual benefit that storage can provide. Changes in network losses are negligible with and without storage. Finally, the stability limits place further restrictions on the operation of storage. This is best understood through an example taken from the 12th June.

7.5.1 *Energy storage operation: 12th June*

The effect of energy storage on the operation of the Shetland power system on the 12th June is shown in Figure 64.

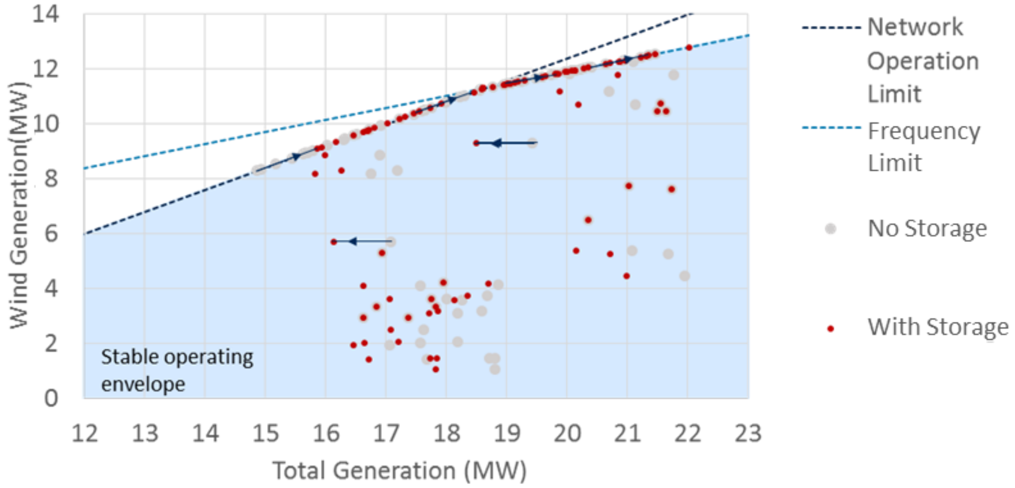


Figure 64: The effect of energy storage on total generation and wind generation at each time-step, 12th June 2011.

Table 23 shows the effect that energy storage has on total generation and wind generation for each time-step during 12th June. The change between the optimal solution with and without energy storage is indicated by the movement of some points.

In the stable operating envelope region, points that move horizontally to the left correspond to periods of discharging of the store; here total generation is reduced whilst wind generation remains the same. The maximum rate of discharge from the store is 0.88MW – the capacity of the energy convertor multiplied by the discharge efficiency – however the exact change in total generation will also reflect any changes in network losses.

Charging is shown by points that move to the right and only occur when wind is curtailed and the points lie on a stability limit. The movement of these points shows an important effect: charging the store increases total generation, but only part of this can be covered by increasing wind whilst maintaining the stability limit. Charging the store at a rate of 1MW cannot use 1MW of wind generation as this would move the point outside the stability envelope. The fraction of wind generation that can be used is defined by the gradient of the limit. For the operational limit the gradient is 0.8, and wind generation can be increased by 0.8MW; the remaining 0.2MW must come from an increase at LPS to maintain the network stability rule.

For frequency stability, the gradient is 0.44 and only 0.44MW of additional wind generation is allowed for each 1 MW demand from the store. When operating at this limit, the ability of the store to raise wind generation is severely restricted. In this example, if the store is charged to 6MWh when the system is on the frequency limit and the store is discharged to offset conventional generation, the total reduction in conventional generation is only 1.26MWh.

The result of the interaction with stability limits is that energy storage in the Shetland context is not very valuable in terms of reducing conventional generation. As generation from the 15MW of viable non-firm wind capacity does not increase significantly the addition of the energy storage unit is also unlikely to increase the viable capacity of wind.

7.5.2 Other benefit streams for energy storage on Shetland

This analysis suggests that energy storage is not valuable in terms of decreasing conventional generation requirements. However, it is valuable in terms of the second part of the NINES objectives: managing peak demand. If the timing and size of demand peaks can be predicted accurately then the ANM scheme can use energy storage to reduce the maximum required output required from conventional generation. This only requires that storage is scheduled to discharge during the daily peak on days when demand is high. In the case of storage studied here this can reduce the peak demand by 0.88MW.

7.6 The benefit of Domestic Demand Side Management

The DDSM scheme provides benefit to the NINES project through the flexibility it creates in the timing of demand, and potentially through its ability to provide a frequency-response.

The project replaces existing domestic space and water storage heaters with ones that can be controlled by the ANM controller. This provides flexible demand units which can be modelled by the structure of flexible demand introduced in Chapter 5. The NINES project included a plan to install and operate between 100 – 200 houses in the next couple of years, but the communications and control infrastructure of NINES allows significantly higher penetration of DDSM to be managed. To investigate the benefit of a large DDSM scheme to Shetland this research studied up to 1750 DDSM-enabled homes spread across the Shetland power system.

Table 27 gives the locations of DDSM-enabled houses across the Shetland power system and refers to the DDSM groups identified in the network diagram of Figure 58. The average house on the DDSM scheme is assumed to contain 2.4kW of water heating and 5kW of space heating. Both water and space heating are assumed to have 5 hours of energy storage capacity (equating to 12kWh and 25kWh respectively).

Table 27: Size and location of DDSM groups on the Shetland power system.

DDSM group	Location	Number of houses	Installed charging capacity (MW)	Installed energy storage capacity (MWh)
FD1	Burradale	1190	10.0	49.48
FD2	Lerwick	180	1.51	7.56
FD3	Mid Yell	105	0.882	4.41
FD4	Brae	200	1.68	8.40
FD5	Sandwick	20	0.168	0.48

The heat-demand profile required by the 1750 houses can be estimated through detailed thermal modelling of the Shetland housing stock, combined with historical records of weather conditions which take into account time-of-year and day of the week[11]. This has been carried out and presented by an academic team as part of the NINES project. An example demand profile for heat for 1750 houses on the 10th January 2011 is shown in Figure 65. This represents the underlying demand component of flexible demand as discussed in Section 5.3.7. The underlying demand is the same regardless of the mechanism of delivery of heat – teleswitching or DDSM.

[11] As noted above, this data has been provided by other members of the NINES research team, it has yet to be published and has been made available to the author before it is in the public domain. A 1 day example of the data is given Appendix 3.

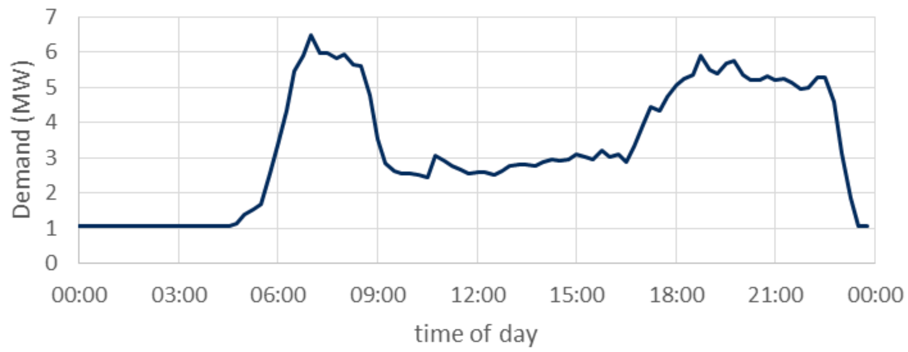


Figure 65: The underlying demand profile for heat in 1750 houses for the 10th January 2011

To model a system containing DDSM, historic fixed-demand profiles are adjusted to account for the removed teleswitched demand and this is replaced with flexible demand. The new fixed-demand profiles can be estimated using the underlying heat demand profile and the schedule of teleswitched houses. Figure 66 shows the fraction of teleswitching capacity that is switched on throughout the day. This profile is the same throughout the year, although the actual demand will depend on weather conditions, time of year, day of the week and other factors.

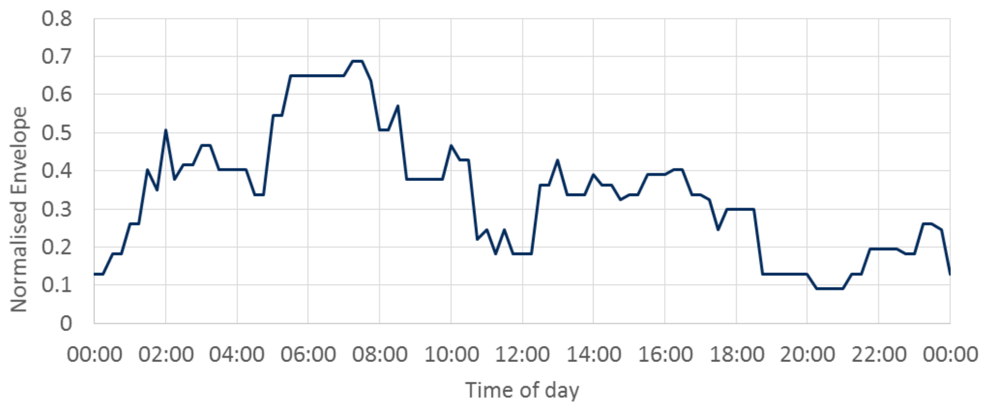


Figure 66: The normalised teleswitching envelope for Shetland. This represents the fraction of capacity switched on at each time-step. The demand at that time-step for a particular day will be within the envelope.

For each day of the year, this envelope is scaled so that the area under the graph is equal to the total underlying heat demand for that day. The resultant year-long profile represents the total reduction in fixed demand at each time-step. This reduction is split across the 5 DDSM locations in proportion to the number of houses at each location.

The flexible demand components of the DOPF model represent the aggregated power and energy capacities at each location as shown in Table 27. The underlying heat-demand profile that they must meet is given by results from the thermal modelling (mentioned above as an input to the DOPF described here) scaled to represent the number of houses at each location.

7.6.1 The benefit of flexible Domestic Demand Side Management

With 15MW of non-firm wind capacity, Table 28 shows the effect on wind generation and conventional generation of flexible DDSM. The installation of 1750 DDSM-enabled homes raises the output of wind generation by 1.73GWh across the year. This has a corresponding effect on conventional generation output, which reduces by 1.62GWh.

The benefit of DDSM corresponds to an average reduction of conventional generation of 0.92MWh per house. This can be given in terms of the effect per MW of installed DDSM capacity, giving 121MWh/MW.

Table 28: Results showing the effect of DDSM on energy generation at WF2, 3 and 4.

	Generation at each wind farm (GWh)				***Total Generation (GWh)***		***Conventional Generation (GWh)***
	WF2	WF3	WF4				
No DDSM	31.91	20.54	2.37		54.82		149.68
With DDSM	31.91	21.93	2.71		56.550		148.06
				Increase:	**1.73**	**Decrease:**	**1.62**

As with energy storage, the interaction of DDSM with the stability rules affect its ability to meet the objectives of the optimisation. Again, this is best discussed with reference to a single day.

7.6.2 Domestic Demand Side Management on the 12th June

As with energy storage, it is useful to study the optimal results for a particular day. Figure 67 shows the scatter plot of time-steps with and without DDSM. The points can be split into three regions: those within the stable operating envelope; those which are constrained by the operational limit; and those constrained by the frequency limit.

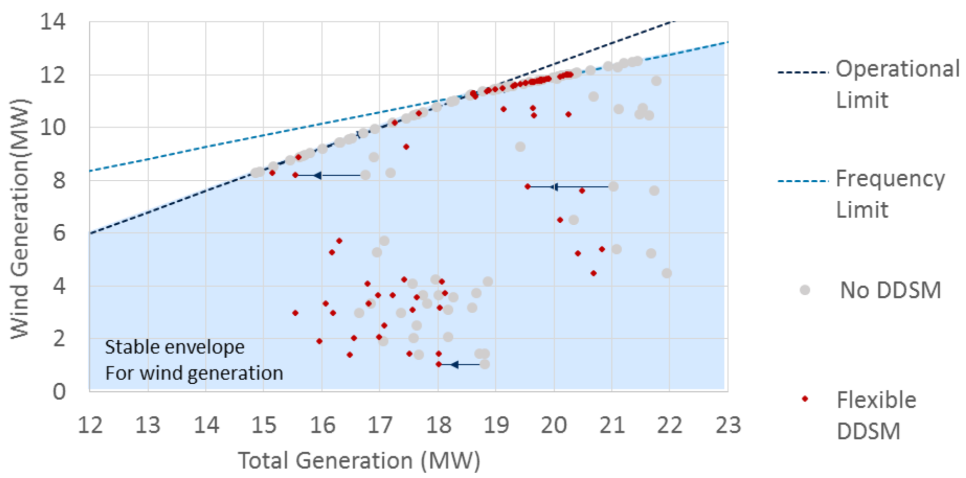


Figure 67: The effect of introducing flexible demand in the form of DDSM on dispatch of generation for the 12th June. Fixed demand is removed at all time-steps and flexible demand is rescheduled. DDSM tends to be scheduled during time-steps where wind generation is limited by the operational limit.

The removal of fixed demand initially moves all points towards the left. Flexible demand is then scheduled only for time-steps that are constrained to lie on a stability limit. The overall effect is to move points on stability limits up and right. As with energy storage, it is not possible to meet all the additional demand during this time-step from wind as this would breach the stability constraint. The fraction that can be met is defined by the gradient of the limit which in the case of operational stability case is 0.8 MW_{wind}/MW_{total}.

Where constraint is due to frequency, the limit has a gradient of 0.44 MW_{wind}/MW_{total}. DDSM is not scheduled for the majority of these points. This is because there is a limited flexible demand to be scheduled. It is more valuable to schedule this limited demand during periods with operational constraint rather than frequency constraint because the gradient of the operational limit is greater than that of the frequency limit. The result is that the majority of points on the frequency stability limit move left, leading to greater curtailment at these times.

7.6.3 Increasing the viable wind capacity with DDSM

The results of Table 28 show that as generation output from the existing 15MW of non-firm wind capacity increases, its capacity factor will increase. In addition DDSM increases the capacity that is viable and a true estimate of the benefit of DDSM should include the benefit derived from this increased viable capacity.

Simulations for a range of installed non-firm wind capacities are repeated with DDSM installed in 1750 houses, and the marginal capacity factor is calculated. Results are shown in Figure 68 for the situation with and without DDSM. With more than 10MW installed non-firm wind capacity, the marginal capacity factor is higher with DDSM due to the reduced curtailment. Using linear interpolation between results of individual studies gives an estimate for the new viable non-firm wind capacity. The addition of DDSM raises this capacity by 0.7MW (i.e. from 15.0MW to 15.7MW).

The benefit of DDSM in reducing conventional generation can now be defined to include (a) the increase in generation output from the already viable wind capacity and (b) the additional generation output by the extra viable wind capacity. The combination of these is shown as the shaded area in Figure 68.

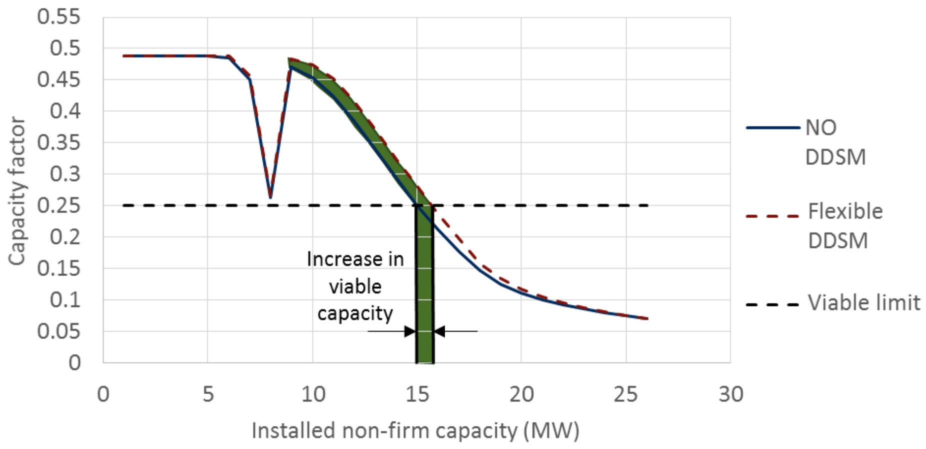


Figure 68: The effect of flexible DDSM on the viable wind capacity. The shaded region shows the total increase in wind generation taking account of the decrease in curtailment at existing wind capacity plus the generation by the increased viable capacity.

Table 29 shows the benefit of DDSM by comparing the total viable capacity non-firm wind capacity without DDSM (15MW) with the situation with DDSM including 15.7MW non-firm wind capacity. The effect on conventional generation is significantly larger than suggested by studying a fixed capacity. The total effect is to reduce conventional generation output by 3.38GWh in total. This corresponds to a benefit of 230MWh/MW DDSM capacity or 1.9MWh/house.

Table 29: Aggregated effect of DDSM including the addition of an extra 0.7MW of viable non-firm wind capacity.

		Total Generation (GWh)		*Conventional Generation (GWh)*
No DDSM, 15MW non-firm wind capacity		54.822		149.68
With DDSM, 15,7MW non-firm wind capacity		58.1		146.3
	Increase:	**3.28**	**Decrease:**	**3.38**

7.6.4 The benefit of frequency-responsive Domestic Demand Side Management

Results for the DDSM scheme shown in Section 7.6.1 show the effectiveness of *flexible* demand. The NINES project also has the potential to make the DDSM *frequency-responsive* as well as flexible. In the context of Figure 67 this results in a relaxation of the frequency limit.

Detailed dynamic modelling of the Shetland power system has been carried out as part of the NINES project. The results show that the effectiveness of frequency-responsive demand is 0.3MW/MW; that is, every 1MW of frequency-responsive demand currently operating allows an additional 0.3MW of wind generation.

To study the effect of frequency-response, the DOPF simulations for DDSM are repeated but with an adjustment to one of the stability rules. Equation (7.14) which defines the frequency stability limit is adjusted to include a term relating to frequency-responsive demand:

$$0.44P_{total} + 3.1 + 0.3P_{ddsm} > P_{wind} \tag{7.16}$$

The studies are initially conducted for 15MW of non-firm wind capacity, and the results for non-firm wind generation and conventional generation are shown in the top half of Table 30 together with results for no DDSM and flexible DDSM. Adding frequency-response capability to the flexibility provided by DDSM creates a significant increase in generation over that of simply flexible DDSM; frequency-response has a significant benefit.

As with flexible DDSM it is possible to identify the additional wind capacity that is viable and Figure 69 plots marginal capacity factor against installed non-firm wind capacity. With frequency-responsive DDSM, 17.1MW of non-firm wind capacity is viable. A final study is run with this non-firm wind capacity and the wind and conventional generation are shown at the bottom of Table 30. The increase in viable capacity of 2.1MW makes a significant difference to the benefit of DDSM.

For frequency-responsive DDSM the total decrease in conventional generation is 8.67GWh, which is 5.95MWh/house or 590MWh/MW.

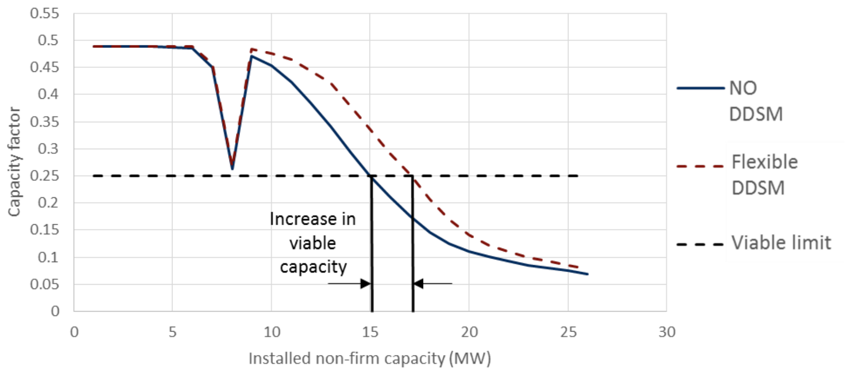


Figure 69: The increase in viable capacity created by frequency-responsive DDSM

Table 30: The effect of frequency-responsive DDSM on both wind generation and conventional generation

		Total Generation (GWh)		***Conventional Generation (GWh)***
No DDSM, 15MW non-firm wind capacity		54.822		149.68
(Flexible DDSM, 15 MW non-firm wind capacity)		(56.55)		(148.06)
FR DDSM, 15MW non-firm wind capacity		58.23		146.51
	Increase:	**3.41**	**Decrease:**	**3.17**
FR DDSM, 17.1MW non-firm wind capacity		63.17		141.01
	Increase:	**8.35**	**Decrease:**	**8.67**

The results shows that frequency-responsive DDSM can benefit the Shetland system by reducing conventional generation by 4.95MWh/house or 589MWh/MW. This is more than twice the effect of flexible DDSM and shows the importance of frequency limits on the Shetland system.

The effect of frequency-response on optimal dispatch of DDSM

There is a significant difference between the optimal schedule for DDSM with and without frequency-response. Frequency-responsive DDSM can now allow significantly more wind generation during periods when the frequency stability limit is binding - but does not affect the operational stability limit. Without frequency-response, 1MW of flexible demand increases viable wind generation capacity by only 0.44MW when the frequency stability limit is binding, with frequency-responsive DDSM this additional viable wind power capacity rises to 0.76MW.

The effect of frequency-response on the schedule for the 12th June can be seen in Figure 70. Without frequency-response, many points remain constrained by the frequency limit. However, with the addition of frequency-response this constraint is released during many time-steps and the points can move above the fixed limit. The operational stability limit remains binding at higher values of total generation.

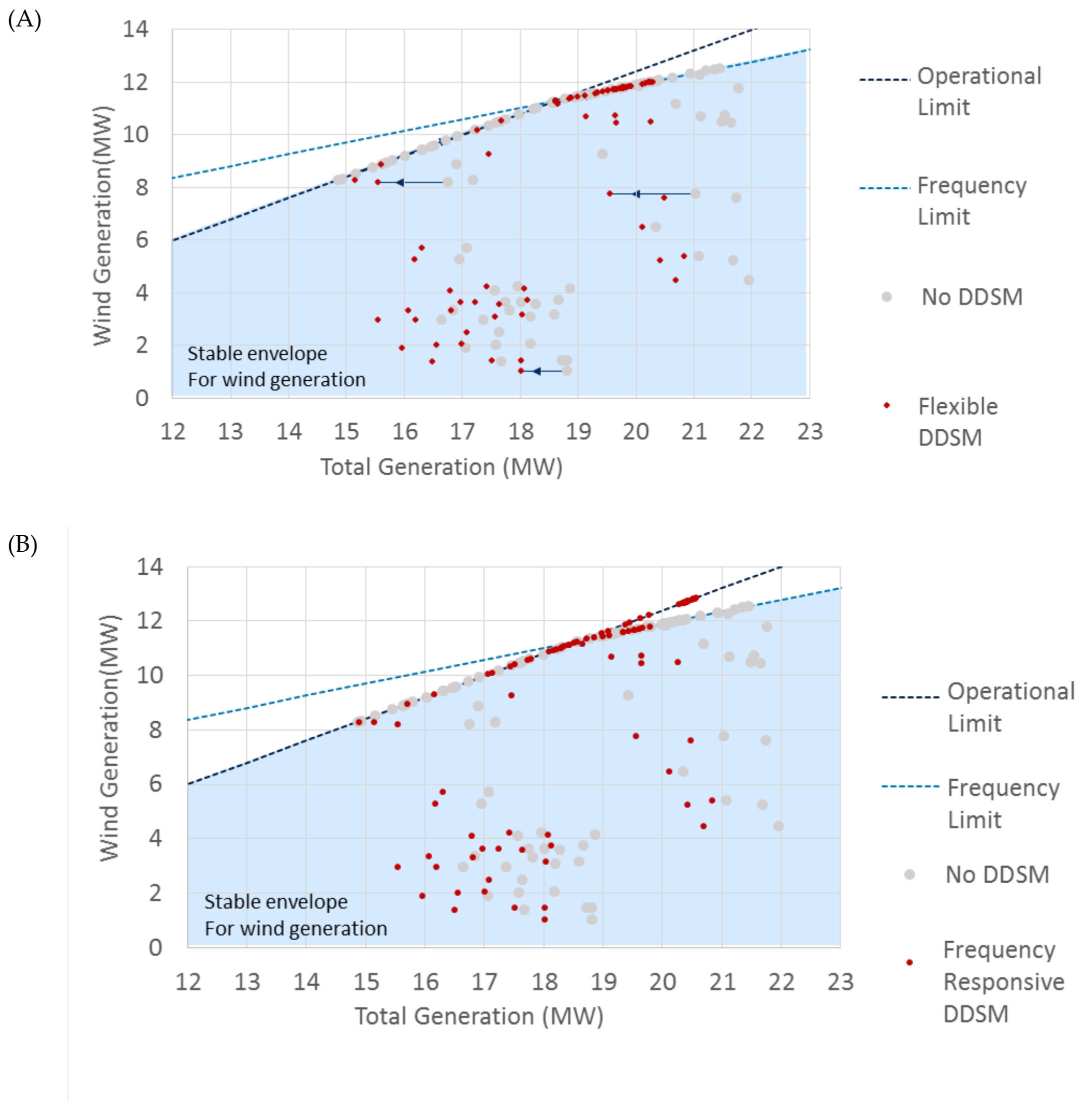


Figure 70: Scatter plot of total generation with (A) flexible DDSM and (B) frequency-responsive DDSM. Note the relaxation of the frequency limit when frequency-responsive DDSM is used.

7.7 Summary of the NINES case study

The ability of DOPF to analyse and provide useful results to the NINES case study has been illustrated in the sections 7.3 to 7.6. The key objective of NINES is that additional wind generation, flexible demand and energy storage should provide a benefit of reducing the cost of electricity generation on Shetland through replacing conventional generation output with wind energy. In terms of reducing generation output by fossil fuel plants, non-firm wind capacity, flexible demand and to a greater extent frequency demand have been shown to have the potential to provide significant potential. A Shetland with 1750 DDSM-enabled homes, that includes frequency-response allows up to 17.1MW of wind generation to be viable. This leads to a total decrease in conventional generation of compared with the current situation of 66.1GWh.

Energy storage is shown to have little benefit due to the lack of significant curtailment reduction and the interaction of generation and the stability rules. However, both energy storage and flexible demand can help to manage the *peak conventional generation* on Shetland. During 2011, the absolute *conventional generation peak* was 46.6MW. Analysis of fixed and flexible demand schedules suggest that DDSM can reduce *peak conventional generation* by approximately 1kW per DDSM enabled house - a total of 1.75MW for the 1750 homes studied here. In addition, as discussed in Section 7.5.2 energy storage can reduce *peak conventional generation* by 0.87MW. Overall this scenario would reduce *peak conventional generation* requirement for 2011 by 2.62MW. The benefit of this peak management is that if it can be guaranteed, the design of the replacement power station for Shetland can be reduced by 2.62MW, with a respective reduction in capital expenditure[12].

Managing DDSM to reduce *peak conventional generation* has the potential to affect its ability to reduce conventional generation output, however for two reasons the objectives are mutually compatible. Firstly, during the period 2010 – 2011 only 5 days were recorded where the daily peak fixed demand was within 3MW of the overall peak. This suggests that if daily peak demand levels can be accurately forecast in advance, peak management is only needed on a small number of days. Secondly, during *peak conventional generation* two circumstances coincide: high fixed demand and low or zero wind generation. In this situation there is no curtailment and DDSM

[12] As with other results in this Chapter, the peak reduction represents that which can in the scenario modelled here rather than in the final roll out of the NINES project.

can be dispatched to manage *peak conventional generation* without significantly affecting total energy generation.

The results of this section are based on the assumption that the DNO has perfect foresight of demand and wind generation for the coming day. The introduction of forecast errors will lead to a reduction in the ability of ANM to meet its objectives. The detailed analysis of the importance of forecast errors is a large and important topic of analysis beyond the scope of this chapter. However, some initial analysis has been carried out for the NINES project [7.14].

7.7.1 The deployment of Dynamic Optimal Power Flow in the Northern Isles New Energy Solutions project

The case study presented here shows the method and the format of the results produced by DOPF being applied in the NINES context. Similar studies have been carried out to model the existing and proposed repowered Shetland power systems. These are being used to inform the design of the ANM scheme.

Whilst it is possible to use the DOPF algorithm directly as part of the ANM solution, this has not been the approach adopted for the NINES project. A key requirement for the ANM controller is that the scheduling engine is based on a simple logic structure using the inputs of system measurements and wind / demand forecasts. The role of DOPF in the design of the scheduling engine is to provide detailed analysis of an optimal solution for historical conditions. The design and tuning of the scheduling engine then attempts to mimic as closely as possible the DOPF results.

7.8 Modelling Shetland with Dynamic Locational Marginal Prices

The Shetland distribution network provides a useful case study for the introduction of Dynamic Locational Marginal Pricing (DLMP) as discussed in Chapter 5. The concept of DLMP extends the use of Lagrangian multipliers on energy balance constraints from OPF to DOPF problems.

This part of the chapter moves beyond current plans for the NINES project and presents an example of results for a DLMP market, using data for the 12th June 2011. The setup is similar to that of the previous scenarios, although some alterations are made to highlight the potential role of DLMPs; the outline is given in Table 31. A total of 17.1MW of non-firm wind capacity is installed and the principle-of-access is changed from *priority order* to *technical best*. Constant marginal cost curves for generation at SVT and LPS are used and the objective of minimising the cost of generation is applied. Energy storage and DDSM are installed as shown in Figure 58 and an additional energy storage unit is added at Burradale, which is able to assist in managing the thermal constraint between WF1/2 and Lerwick.

The cost of generation at LPS and SVT are estimated from generic values for heat rate and fuel costs for gas turbines and diesel generators and the costs are listed as part of Table 31. It should be noted that these do not reflect the actual costs of generation on Shetland. Stability rules remain unchanged. This scenario used values for demand and wind generation values for the 12th June introduced earlier in this chapter.

Table 31: Setup for the DLMP study of the Shetland power system

Component	Location	Description	
WF2	Burradale	9MW	Marginal cost of all wind = 0. Technical best principle-of-access
WF3	Unst	5MW	
WF4	Lerwick	5MW	
WF5	Sandwich	1MW	
DDSM (frequency-responsive)	Brae	200 houses. Power capacity : 1.68MW Energy Storage: 8.5MWh	
Energy Storage 1	Lerwick	1MW/6MWh 77% efficient	
Energy Storage 2	Burradale	1MW/6MWh 77% efficient	
SVT	Sullom Voe	Marginal Cost = £80/MWh Max output = 23MW	
LPS	Lerwick	Unit 1: Marginal Cost = £150/MWh Maximum output = 10MW	
Stability rules		As previous (see Section 7.3)	

7.8.1 Base case analysis

The DOPF algorithm is run with no non-firm wind capacity, representing the current situation. In this scenario the control actions available to the algorithm are simply to minimise overall costs at each time-step by dispatching SVT and LPS. The DLMPs are the same as the simple LMP values which would be achieved by running a separate OPF for each time-step; they represent the cost associated with marginal demand at a particular location at a particular time.

The DLMP values for selected buses are plotted in Figure 71. The highest prices occur at Sumburgh at the southern extremity of the network. Demand here is associated with high losses. At all times of the day the marginal cost of generation at Lerwick is £100/MWh and at SVT it is £80/MWh, and variations from this are due to network losses. The least-cost solution involves dispatching LPS at its minimum value of 20% of total required generation and dispatching the remainder of the generation requirement (after firm wind has been used) from SVT. Without losses the marginal cost of meeting additional demand would be the same across the network:

$$0.2 \times \frac{dC}{dP_{LPS}} + 0.8 \times \frac{dC}{dP_{SVT}} = £94/MWh \tag{7.17}$$

Including losses in the calculation means that increasing demand at Lerwick increases losses. The majority (80%) of the increase in generation occurs at SVT due to its lower cost, and this leads to increased losses between SVT and Lerwick (the additional 20% from LPS is simply to maintain the operational stability limit). The DLMPs at Lerwick range from £99.56MWh - £107.43/MWh. The DLMPs at locations in the North of Shetland are significantly lower as they tend to reduce power flow on the line between SVT and Lerwick. DLMPs for both Brae and Unst are shown in Figure 71 and are much closer to the no-losses value. DLMPs at some buses, notably at SVT itself are less than £94/MWh, as increasing demand here will reduce overall losses, as a greater proportion of LPS generation is used to meet Lerwick demand.

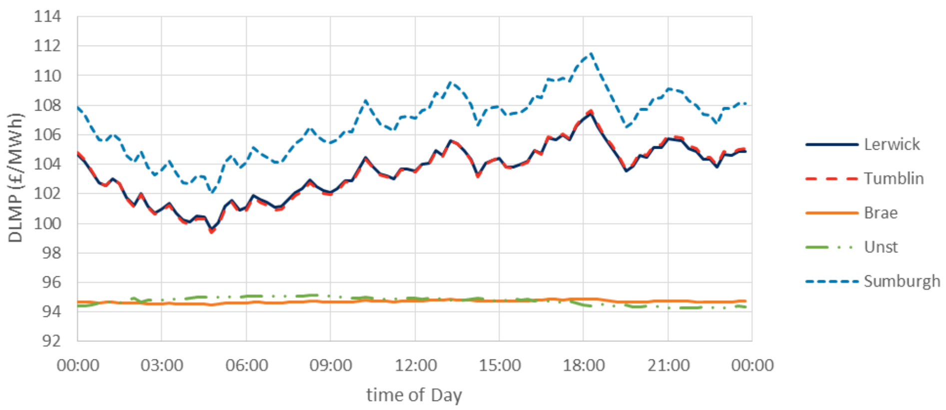


Figure 71: DLMP values for selected locations for the 12th June with no non-firm wind.

Values for the payments by consumers, payments to generators, cost of generation and merchandising surplus in this study are shown in the first column of Table 32.

7.8.2 Non-firm wind

Installing additional non-firm wind capacity will lead to significant changes in the structure of DLMPs, because when non-firm wind is curtailed there is the opportunity for some wind generation to contribute to meeting marginal demand increases, therefore lowering the DLMPs in these periods. The stability rules do not allow *all* of the marginal demand to be met via wind so the DLMPs will not go to zero. As there are still no intertemporal linkages, the DLMPs remain the same as the LMPs that would be found from solving individual OPFs for each time-step.

Table 32: Payments and merchandising surplus for the 12th June using DLMP

Component	Base Case	With NF Wind	With Energy Storage	With Flexible Demand
Payments by consumers (£1000)	44.94	31.08	32.71	32.5
Payments to conventional generation (£1000)	37.64	17.83	17.76	17.26
Payments to firm wind (£1000)	5.73	3.22	3.55	3.67
Payments to non-firm wind (£1000)	N/A	9.39	10.43	10.88
Total payments to generators (£1000)	43.73	30.43	31.75	31.81
Cost of generation (£1000)	**38.30**	**25.46**	**24.99**	**24.50**
Generators' surplus (£1000)	5.07	4.97	6.76	7.31
Merchandising surplus (£1000)	1.57	0.65	0.96	0.69

Figure 72 shows the DLMPs for locations in the network with the addition of 15MW of non-firm wind capacity. A key difference is the increase in variability seen in the DLMPs compared to the situation without non-firm wind capacity. Three distinct cost regions can be identified: (i) when there is no curtailment, DLMP values are similar to those without non-firm wind capacity; (ii) when the operational limit is binding then prices are low since marginal demand can be met with 20% from LPS and 80% from non-firm wind; and (iii) when the frequency limit is binding prices are at an intermediate level as 56% of marginal demand can be met from conventional generation and 44% from non-firm wind.

Non-firm wind capacity reduces the costs of generation by displacing expensive conventional generation as listed in column 3 of Table 32. Payments by consumers and to generators are also reduced through the lower DLMPs.

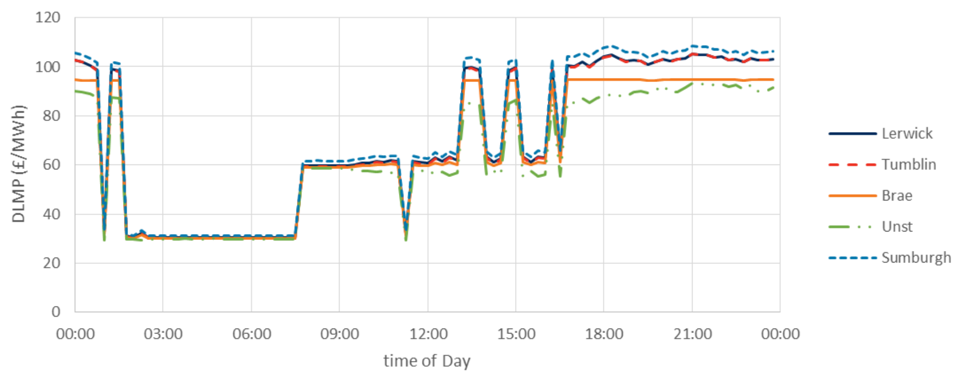


Figure 72: DLMPs at selected locations with 15MW of non-firm wind capacity.

It is interesting to note that the addition of non-firm wind capacity at Unst reduces the DLMP at this location when wind generation is available. This is because demand at Unst now reduces power flow out from the Unst bus, therefore reducing losses. Even when no curtailment is being applied, the DLMP at Unst can be less than £94/MWh.

7.8.3 Energy storage

The addition of energy storage can increase non-firm generation, although results from Section 7.5 have shown that this effect is minimal. Despite this, it changes the structure of DLMPs. Figure 73 shows the DLMPs at Lerwick with and without energy storage and the charge / discharge schedule for the storage device. Energy storage reduces DLMP values during a few time-steps, although it raised prices during a greater number of time-steps.

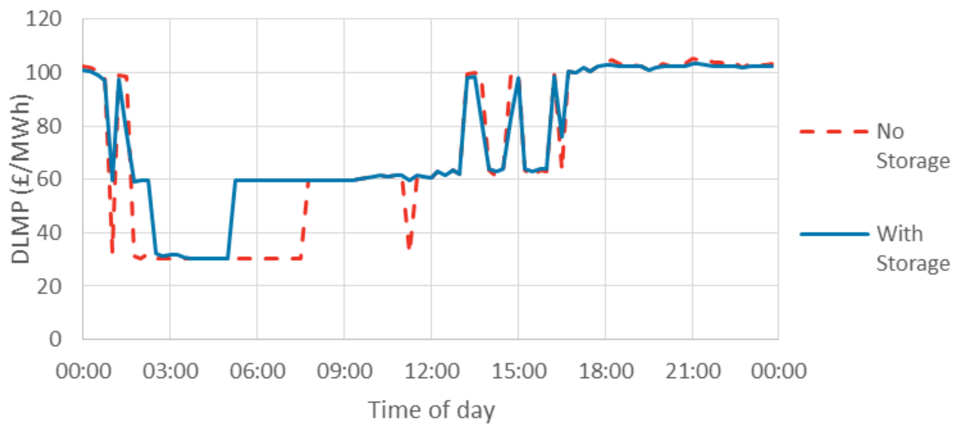
The column 4 of Table 32 breaks down the payments for a scenario with energy storage and shows that the operation of energy storage reduces the cost of generation but increases payments by customers, compared with non-firm wind capacity only. Both the generator surplus and merchandising surplus increase. The increase in generator surplus is due to increased generation from and payments to non-firm wind with zero marginal price. The increase in merchandising surplus relates to the losses in the energy storage device.

As discussed in Chapters 4 and 6, energy storage will charge when the price is low and discharge when the price is high. In a DOPF problem this is achieved through minimising the objective function and the prices at nodes representing a bus to which storage is connected depend on the action of the store. The majority of charging in the optimal solution of Figure 73 occurs between 02:30 and 09:15. Apart from a small amount at 11:15 there is no charging after 09:15, even though from Figure 62 it can be seen that there is still curtailed non-firm wind available. The DOPF has found the schedule for the storage that minimises the overall cost of generation across the optimisation-horizon. The optimal solution involves charging the store when wind is constrained due to the operational constraint - as at these times 80% of charging can be met through increasing wind generation with zero cost. If at a particular time-step charging of the store increases total generation enough that wind is now constrained by the frequency limit, the DLMP value will rise from the low price of around £30/MWh to the intermediate price of around £60/MWh. This can be seen to happen between 05:30 and 07:30.

Discharging occurs when wind is not constrained and the DLMPs are around the high value of £100/MWh. Discharging will not lead to further constraints during these time-steps as this would be sub-optimal, as such discharging tends not to affect the DLMPs significantly.

In the NINES scenario studied here where DLMP values are linked to the system-wide stability limits, energy storage decreases the costs of generation but leads to increased payments by consumers. Can the energy storage be said to benefit consumers?

(A)



(B)

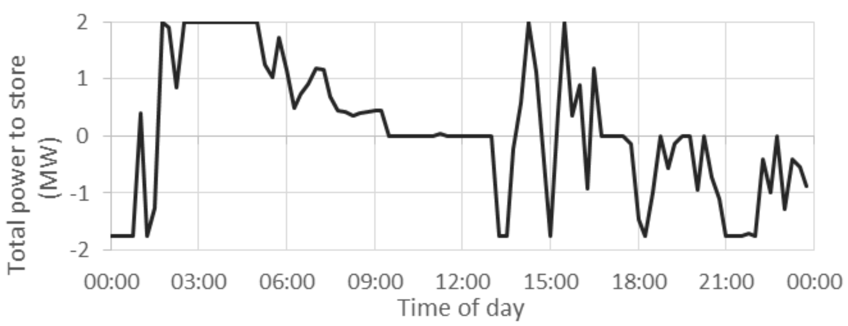


Figure 73: (A) DLMP values for Lerwick on the 12th of June with and without energy storage and (B) Combined schedule for the two energy storage devices.

One benefit is the reduction in variability of the DLMPs. The mean DLMP value for Lerwick rises with the addition of energy storage (from £70.37/MWh to £74.25/MWh), but the standard deviation drops (from £29.65/MWh to £24.28/MWh). The trend in mean DLMP values and their standard deviation is shown in Table 33 for larger capacities of energy storage. Increasing storage capacity leads to smaller DLMP standard deviations. The advantage of storage to customers is therefore reduced variability in prices.

Figure 74 shows the time-series of Lerwick DLMPs with the different capacities of storage from Table 33. Variability of DLMPs is not removed even for very high installed capacities of energy storage because of storage inefficiency. The increase in prices between the charging and discharging of the store must be greater than the efficiency losses in the store. The line for the infinitely large store in Figure 74 produces a two-level profile of DLMPs. The value of the two levels are £86.39/MWh and £66.52/MWh and the ratio of these prices is 0.77 – exactly equal to the round-trip efficiency of the store.

Table 33: The effect on the mean and standard deviation of DLMPs at Lerwick with increasing capacity of installed energy storage

	No Store	12MW/6MWh	120MW/600MWh	Inf/Inf
Mean (£/MWh)	70.37	74.25	77.24	75.01
Standard deviation (£/MWh)	29.65	24.28	14.44	9.83

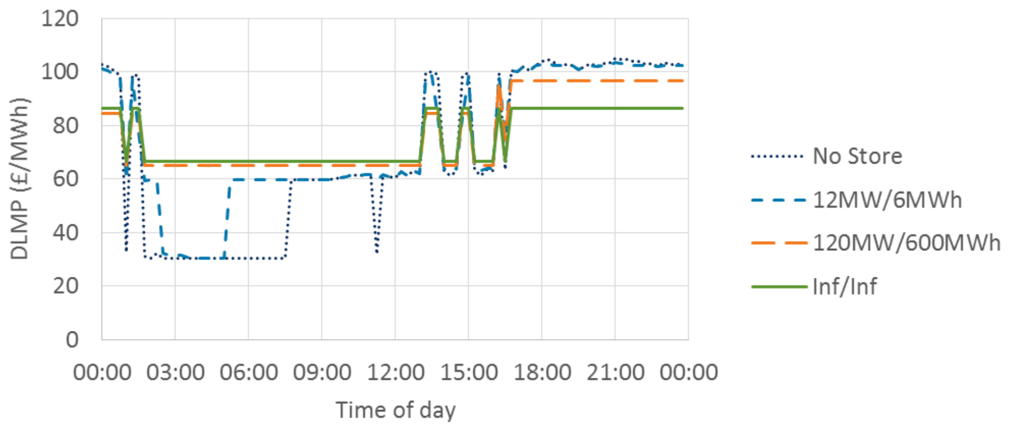
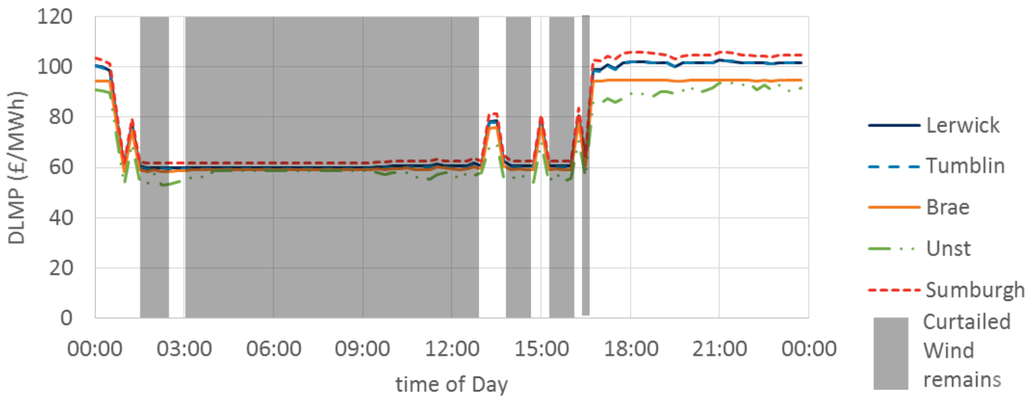


Figure 74: DLMPs at Lerwick with increasing installed energy storage capacity.

7.8.4 Domestic Demand Side Management

Finally, adding flexible DDSM across the network leads to a further change in the structure of the DLMPs. It reduces both the payment by consumers and the cost of generation (the latter compared with only energy storage). DLMPs across the network with both DDSM and energy storage connected are shown in Figure 75 A. Aggregate demand schedule (fixed demand plus flexible demand) with and without DDSM in shown in Figure 75 (B). The addition of DDSM reduces the variability of DLMPs across the network. Merchandising surplus reduces slightly but generator surplus increases.

(A)



(B)

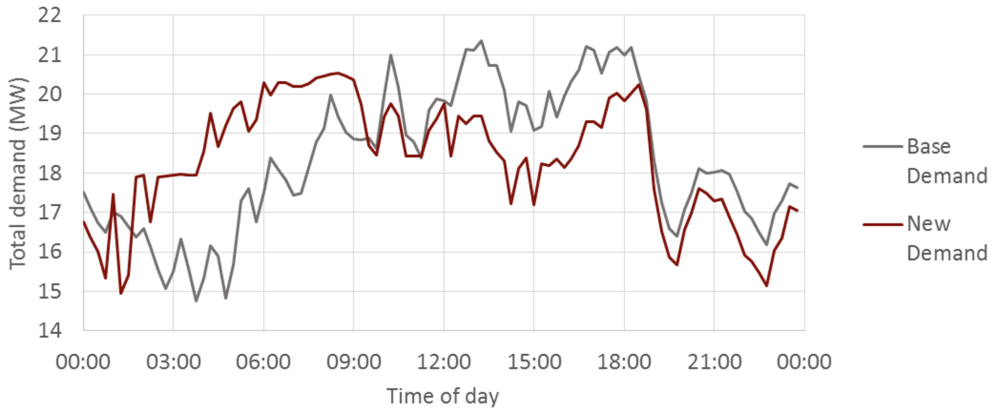


Figure 75: (A) DLMPs across the Shetland network with DDSM and energy storage and (B) total demand scheduled across the day with and without DDSM.

As with energy storage, DDSM is scheduled to charge during periods of lower DLMP which correspond to time-steps with wind constrained by the operational stability limit. Scheduling DDSM at these time-steps reduces the overall cost of generation, as more wind generation is used to meet the same total energy demand. Payments by consumers also decrease because more demand occurs during low price time-steps. The structure of the DLMPs in Figure 75 (A) is such that prices are approaching a 2-tier structure with a DLMP of around £60/MWh when curtailed wind generation remains, and DLMPs of around £100/MWh when there is no wind curtailment. There are also a small number of time-steps with DLMPs around £80/MWh for which there is no remaining wind curtailment. To understand better the effect of marginal demand at different time-step, studies are run with a fixed demand increase of 0.1MW at Lerwick for 06:00, 21:00 and 15:00 – time-steps with DLMPs at the three levels identified.

1. **An increase of 0.1MW in demand at 06:00:** leads to an increase in generation at LPS, SVT and non-firm wind during all periods between 04:00 – 09:15. Rather than an increase in generation only at 06:00, the intertemporal linkages provided by DDSM spread the increase in generation across multiple time-steps. Rescheduling of DDSM over multiple time-steps minimizes the increase in network losses and meets 44% of the increase from wind generation in line with the binding frequency stability limit.
2. **An increase of 0.1MW in demand at 21:00:** leads to an increase in generation at SVT and LPS at 21:00 only. There is no DDSM scheduled at 21:00 and no curtailed wind, therefore it is not possible to meet this demand any more economically than to generate the electricity at the same time as the demand.
3. **An increase of 0.1MW in demand at 15:00:** this corresponds to a time-step at which there is no curtailed wind generation available and the DLMP is around £80/MWh. To meet the additional 0.1MW, energy storage discharge is increased by 0.1MW at 15:00. This leads to a complex re-dispatch of energy storage and flexible demand between 09:30 and 16:00. The 0.1MW increase in discharge results in additional wind generation (44%) and conventional generation (56%) during other time-steps and transferred by the energy storage to 15:00. The storage inefficiency imposes an additional loss component on the DLMP at 15:00 compared with that of 06:00 (where marginal demand is met by re-dispatch of DDSM). The ratio of the DLMPs for 06:00 and 15:00 is 0.76 almost equal to the energy storage losses. The small difference from 0.77 is due to changes in network losses.

This analysis of DLMPs highlights some important points. Firstly it highlights how energy storage and flexible demand link time-steps together: to understand the concept of DLMP it is not possible to concentrate on the additional generation required to meet demand *at the same time*, instead it depends on the changes in generation profiles across the whole optimisation time-horizon.

Secondly, it shows that energy storage and flexible demand will alter the relationship between payments to generators, payments by consumers and merchandising surplus. The increase in merchandising surplus seen when energy storage is installed is an interesting example. Part of merchandising surplus is to allow the network to recover the cost associated with losses. In DOPF energy storage is considered as part of the network and therefore the cost of its losses form part of the cost of network operation and should be covered by the merchandising surplus. It also shows that when considering consumers, the objective of minimising the cost of generation may no longer be appropriate for minimising the cost to consumers.

7.9 Conclusions

The application of DOPF to inform the design of a real ANM system is a significant advance. This chapter has shown how the DOPF method has become part of the design process of a bespoke ANM system for the Shetland Islands. As part of this, the DOPF formulation of Chapter 5 has been extended and adapted to deal with the specific requirements of the Shetland ANM scheme. This demonstrates the versatility of the method and how designers of second-generation ANM schemes can employ it.

Specifically, the concept of a stable envelope of wind generation has been developed which takes account of technical and non-technical stability issues. The linear bounds of this envelope are included in the DOPF formulation and historical data for Shetland are used to carry out year-long studies into the benefit of non-firm wind capacity, energy storage and DDSM. Results show that energy storage on Shetland has little value in terms of reducing conventional energy generation, due to its interaction with the stability rules. It is noted however, that energy storage does have a benefit in terms of the management of *peak conventional generation*. By contrast, DDSM gives significant benefit in reducing conventional generation, which comes in the form of reduced curtailment and increased capacity of non-firm wind that is viable. If DDSM is able to provide frequency-response to the system - and therefore relax the frequency stability limit on wind generation, then the benefit in terms of conventional generation output reduction more than doubles.

Finally the use of DLMPs has been illustrated in the Shetland context. The theoretical formulation from Chapter 6 is discussed in the specific context of the Shetland Islands, including operational stability rules and the intertemporal linkages created by energy storage and flexible demand.

Non-firm wind capacity is shown to significantly reduce DLMPs during some time-steps but at the expense of introducing large variations in prices between time-steps. Energy storage, whilst reducing the costs of generation, also increases merchandising surplus and leads (in the example) to a small increase in payments by consumers. A key benefit that energy storage does provide is that it can mitigate variations in DLMPs. Including DDSM further reduces the costs of generation and reduces payments by consumers. It also significantly reduces the variation in DLMPs.

This chapter has focused on the application of DOPF to a specific ANM system. As such it has dealt with the issues of a particular power system. The work, whilst producing a number of important contributions to knowledge, does help to identify several areas for further work. The discussion of these form an important part of the next and final chapter.

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Chapter 8: Conclusions

THE WORK PRESENTED in this thesis has developed three tools that allow the analysis of ANM schemes containing energy storage and flexible demand: a linear programming optimisation (Chapter 4), Dynamic Optimal Power Flow for Active Network Management (Chapter 5) and Dynamic Locational Marginal Pricing (Chapter 6). It has also presented analysis of several case-study networks, culminating in the detailed description of the application of DOPF to the Shetland ANM scheme (Chapter 7).

This chapter concludes the research presented, and relates it to the objectives and thesis questions defined in Chapter 1. It brings together and summarises the evidence for the contributions to knowledge that the thesis delivers and it lays out the future work suggested by the thesis.

8.1 Review of conclusions

Each chapter of the thesis provides a perspective on the main thesis question:

- How can energy storage and flexible demand be scheduled in a second-generation Active Network Management (ANM) scheme? How should they be operated to gain the most benefit for distributed wind generation?

8.1.1 Conclusions from the review of literature on existing ANM schemes and optimisation methods

Chapters 2 and 3 reviewed the existing literature on ANM and optimisation of distribution networks respectively. The conclusions of these chapters identify gaps in the literature which this thesis addresses.

In Chapter 2 the philosophy of ANM, as developed in the UK is reviewed and contrasted with the development of market-based methods in active distribution networks elsewhere in the world. This review identifies the following conclusions:

- ANM has a relatively centralised control philosophy based on the measurement and communication of network conditions to a centralised controller which makes decisions on the operation of network components, sometimes known as 'locally centralised'. There is some distribution of control to network components, particular wind farms, but this is restricted to *how* to achieve the action defined by the central controller and how to react to communication failure and faults. Developments in active distribution networks outside the UK show examples of greater distribution of control through, for example, market based pricing mechanisms. As such, it is expected that in the future ANM schemes will continue to cede centralised control.
- The deployment of ANM up to 2013 has been based almost entirely on systems which monitor and control devices in real-time. Technologies and techniques deployed, such as generation curtailment, do not have intertemporal linkages. Such schemes have been designated in this thesis as first generation ANM. Plans for future ANM schemes, including some which are coming online during 2013, include intertemporal technologies. Operation of these technologies during one time-step affects operation during other time-steps.
- First generation ANM is becoming business-as-usual on UK distribution networks. The move towards intertemporal technologies and greater

distribution of control constitute a second-generation of ANM. In these schemes, the controller will have to take a greater role in scheduling intertemporal technologies in advance of operation.

These conclusions highlight the need to understand how second-generation ANM schemes should operate, and the need to develop the tools to analysis them. The need for intertemporal optimisation tools is clear as is the incorporation of intertemporal technologies into market analysis. Optimal Power Flow (OPF) currently provides a useful analysis tool for existing first generation ANM schemes, however there is limited literature on OPF based techniques to tackle second-generation ANM schemes. Chapter 3 presents a review of the literature on optimisation of distribution networks, particularly focusing on OPF. The key conclusions are:

- OPF formulations allow the modelling of existing control mechanisms within first generation ANM schemes. Such methods are not intertemporal and can optimise controllable devices separately for each time-step.
- The optimisation of first generation ANM schemes is well covered by existing literature, which includes methods of applying generation curtailment and voltage control. One notable exception is the modelling of principles-of-access for non-firm generators in generation curtailment schemes where little research has been brought forward.
- Some multi-period OPF methods have been presented which, for example, limit the curtailment at any one wind farm across a year. These methods are not suitable for modelling energy storage and flexible demand as they do not model the *order* of time-steps.
- The value of full multi-time-step or Dynamic Optimal Power Flow (DOPF) is identified. A small number of papers have made some progress to adapting this method to one that can address issues relating to distributed energy storage and flexible demand. However, a number of important gaps in the existing formulations are identified.

- There have been no studies to date into the analysis of the economic information contained in the solution to a DOPF problem.

An objective of this thesis is to develop tools capable of analysing second-generation ANM schemes including intertemporal technologies. The literature review shows the DOPF is a useful tool for this, but identifies that little work in this area has been done. The gaps identified includes the development of fully flexible models of energy storage and flexible demand, and the application of these tools to realistic systems. Through analogy with Locational Marginal Pricing (LMP) the literature review suggests that useful economic information is contained within the optimal solution of a DOPF problem. This information has the potential to be used in future market based ANM schemes as well as at transmission level. This aspect of DOPF is developed in Chapters 6 and 7 where it is shown that the extension of LPMs to the solution of a DOPF allow the economics of storage and demand flexibility to be investigated. The technique is shown to be powerful at finding the efficient economic solution to the problem of scheduling of energy storage and demand flexibility. For example leading to a solution in which energy storage reduces price variations until the point at which the ratio of price variations is equal to the round trip efficiency of the store.

To summarise the two literature review sections: in the coming years ANM will develop a second-generation of applications including intertemporal technologies and it is likely that they will show greater distribution of control. Analysis of such schemes is important and has yet to be presented in any detail in the literature. DOPF based tools will be useful for analysis of such schemes. The research of this thesis has developed tools and conducted studies to fill these gaps.

8.1.2 Conclusions from a linear programming model

Chapter 4 presents an initial study into the operation of energy storage in a distribution network. Simplifying the distribution network to a single bus and applying a linear programming energy-balance optimisation allows it to analyses the optimal operation of the energy storage in reducing curtailment of wind generation and carrying out price arbitrage. The study leads to some important conclusions on the scheduling of energy storage:

- The benefit of distributed wind, and of ANM schemes in general, can be defined in a number of ways: directly in terms of renewable energy generated; indirectly in terms of the increase in net energy exported from the distribution network; or in terms of financial value associated with the flow of energy through the grid connection point from / to the external energy market. The final two definitions relate to the *effect* of distributed wind generation rather than simply its energy output and it is concluded that the use of these two objectives is more useful than simply maximising generation from distributed wind.
- Energy storage should be operated to charge and discharge frequently to maximise benefit, both in terms of reducing wind curtailment and increasing export revenue from an ANM scheme.
- An important benefit of energy storage is that it can access multiple revenue streams and therefore provide benefit through several mechanisms. The study illustrates this by showing that the combined benefit of curtailment reduction and price arbitrage is greater than either on their own even though the two objectives can conflict at times.
- The importance of high-efficiency storage devices is shown in terms of maximising the *effect* of distributed wind; it is noted that low efficiency storage devices can have a greater effect on increasing the energy generated by distributed generation. This highlights the importance of well-chosen objectives.
- Renewable subsidies which reward simply the generation, rather than the use of energy, are identified as an example of when the objective of increasing generation can have an undesirable result. An example is used to show that there is the potential for existing renewable subsidies to encourage development of low-efficiency energy storage over high-efficiency storage.

- A cost benefit analysis concludes that currently battery energy storage is unlikely to be economically viable in the case study ANM scheme. To break even, the capital costs of a sodium sulphur battery would need to approximately halve.

In summary, gaining the greatest benefit from distributed wind and ANM in this scenario involves using a highly efficient energy store which is able to access curtailed wind generation and carry out arbitrage. The linear programming optimisation is the first example from the thesis of the development of a tool that can analyse intertemporal distribution networks. Whilst studying a simplified scenario provides insights into future ANM schemes containing energy storage. Examples include the analysis of subsidies which concludes that existing renewable subsidies based simply on the quantity of electricity generated have the potential to encourage low efficiency energy storage over high efficiency generating.

8.1.3 Dynamic Optimal Power Flow for Active Network Management

The development of DOPF, its use in scheduling energy storage and flexible demand, and analysis of the economic information it contains is an important contribution of this thesis. Developing a DOPF framework suitable for ANM requires the use of a full AC-network formulation, developing methods for implementing principles-of-access for non-firm generation, and modelling energy storage and flexible demand. The development of the framework provides a number of contributions to the overall thesis question. These are:

- The development of the concept of the DOPF framework models intertemporal technologies as branches linking nodes at different times. The overall DOPF network can transfer energy geographically and temporally to meet demand in a way that minimises the objective function across the optimisation time-horizon.
- The thesis formulates priority-order principle-of-access for non-firm generators and applied this to the case study. Priority order is chosen as it is the principle-of-access employed in existing ANM schemes. The framework

presents formulations of other principles-of-access (shared percentage) although this is not applied in the case studies.

- A formulation of energy storage which gives full flexibility in terms of modelling efficiencies and the freedom on when to schedule charging and discharging.
- A model of flexible demand is introduced which highlights the similarities between flexible demand and energy storage.

The application of the framework to a simple ANM scheme including energy storage, flexible demand, non-firm generation and priority order principles-of-access. The initial case study leads to the following conclusions:

- Energy storage and flexible demand can increase the benefit from distributed wind when scheduled using DOPF. It highlights that energy storage can provide both real and reactive power dispatch.
- Intertemporal technologies are dispatched to support non-firm generators in line with the priority order. This identifies the need to consider a 'principle-of-access to intertemporal technologies'. This is particularly important because control actions involving intertemporal devices owned or operated by the DNO directly affect the curtailment at different wind farms; in this case the DNO is actively affecting network access rather than passively managing what is there.
- Analysis of a network with greater capacities of energy storage confirms the conclusion of the linear programming formulation that the benefit created by energy storage drops off with the increase of capacity of energy storage.

The development of a DOPF suitable for ANM is an important contribution and delivers a technique and associated tool which can be used in the detailed analysis of second-generation ANM schemes. The analysis presented in the case study concentrates on the intertemporal technologies. Existing OPF techniques for modelling non-intertemporal technologies, notably voltage control techniques can be added into the framework and applied separately at each time-step.

In addition to the scheduling ability of DOPF, an optimal solution is shown to provide detailed economic information. The thesis has developed the foundations of a theory of Dynamic Locational Marginal Pricing (DLMP) which extends the existing theory of Locational Marginal Pricing (LMP) from OPF solutions. The insights of this part of the thesis can be summarised as follows:

- The Lagrangian multipliers associated with the nodal energy balance constraints in a DOPF problem act in an analogous way to those in an OPF problem. They can be used to define nodal prices which represent DLMPs – when interpreted as the price at a particular location and particularly time-step, a single DOPF solution provides prices across the geographical and temporal extend of the optimisation.
- Merchandising surplus can be extended to become Dynamic Merchandising Surplus (DMS), which includes the effect of both network and energy storage.
- Energy storage and flexible demand can both reduce the DMS and payments by consumers. However, the efficient flexible demand modelled in this thesis can reduce DMS to a greater extent than inefficient energy storage. In the simple case study presented, flexible demand was able to almost completely remove merchandising surplus by removing network congestion without adding additional losses or constraints. Energy storage by contrast can add to both losses and constraints.
- The multipliers on energy and power constraints of energy storage give information on the marginal benefit of relaxing those constraints – this corresponds to adding either energy or power capacity to the energy store.
- The concepts of DLMP can be used to calculate the payments to generators and by consumers across the optimisation horizon.
- The benefit of intertemporal technologies can be defined in terms of the reduction in costs (the objective), the changes in payments to generators or payments by consumers. The method allows a detailed analysis of monetary flows between participants on the network in the optimal DOPF solution.

The concept of DLMPs highlights the benefit of modelling intertemporal technologies, particularly energy storage, as network branches. It removes the need to consider what 'bids' and 'offers' energy storage would place for charging / discharging. Instead, the benefit can be identified in terms of overall cost of generation. That the energy storage is only making economically efficient transfers between time-steps is assured by the optimisation. For example, power will only flow between time-steps if the price differential between them is large enough to cover efficiency losses, as only if this is true will it minimise the overall cost of generation.

8.1.5 Conclusions from applying Dynamic Optimal Power Flow to a real Active Network Management scheme

The final section of this thesis involves the application of DOPF to an industrial ANM project based on an islanded distribution network. This section is important as it shows that the theory presented throughout the thesis has the ability to provide real insight into both current and future ANM projects. Major industry engineering tend to require bespoke solutions focused directly on the project in question. The Shetland ANM scheme discussed in Chapter 7 is an example of such a project, and the application of DOPF to this problem requires modification of the formulation developed in Chapter 5 to model stability constrains relating to the small islanded network. The key learning presented in this final section can be summarised as follows:

- The DOPF framework can be modified to provide an operational formulation for modelling the specifics of a particular problem, in this case the stability issues associated with operating an islanded network.
- The concept of the *stable envelope for wind generation* used to define operation of wind as a function of total system generation is presented, along with and the formulation of the envelope into constraints within the DOPF framework.
- Results are provided for a year-long analysis of a realistic scenario similar to that studied in the industrial project.

- In the islanded context studied, energy storage in the form of electrochemical batteries provides little benefit in terms of reducing conventional generation, although it does have value in managing peak demand.
- Results from modelling flexible demand in the form of Domestic Demand Side Management (DDSM) of electrical heating show significant benefit. In terms of decreased conventional generation, flexible DDSM has a benefit of 121MWh per MW of installed flexible generation across the year.
- Results for frequency-responsive DDSM show an even greater benefit, reducing conventional generation by up to 589MWh per MW of installed frequency-responsive demand across the year.
- DOPF modelling results have been used to support the Shetland ANM project by informing the design of a simple logic-based scheduling engine being designed by the project ANM provider. The DOPF results play a role in tuning the parameters of this scheduling engine.

In addition to describing the role of DOPF in informing the ANM design for Shetland, the case study carries out analysis of the optimal solution for a day in terms of DLMPs to investigate the roll of energy storage and flexible demand in changing the structure of payments within an optimally scheduled solution:

- The addition of non-firm wind generation reduces the average payment by consumers, payments to generators, generators' surplus and merchandising surplus. From a consumer / generator perspective the negative effect is that the prices fluctuate significantly between time-steps.
- Energy storage is shown to alter the financial payments. Whilst it does reduce the overall cost of generation slightly, it increases the payments by consumers, leading to greater merchandising and generator surpluses. It does however reduce the variability of prices, and studies with large generation capacities show that this extends until prices across the day reach a two-tier solution with the ratio of the two prices equal to the inverse of the round-trip efficiency of the store.

- Flexible demand in the form of DDSM reduces payments by consumers and payments to generators. The variability of prices is also significantly reduced.
- The combination of non-firm wind generation, energy storage and flexible demand reduces payments by consumers to 72% of the original level, and payments to generators by 73%. Generators' surplus is higher by 44% because a significant quantity of the payment to generators goes to zero-marginal cost wind.

8.2 The contribution to knowledge

In Section 1.4 the thesis asks the questions: How can energy storage and flexible demand be scheduled in a second-generation ANM scheme? And how should they be operated to gain most benefit from distributed wind generation? The summary of conclusions in the previous section highlights how the thesis has met these objectives by developing and deploying tools for analysing the optimal dispatch of energy storage and flexible demand in ANM schemes and conducting studies with these tools. In the process the thesis has developed novel techniques and contributed to engineering knowledge. This section summarises the contributions laid out in Section 1.5.

8.2.1 The first study of effect of energy storage on operation of ANM

The review of optimisation studies for ANM showed that very few studies have looked at energy storage in distribution networks and none at the specific case of ANM. Chapter 4, in carrying out a detailed study of a simplified model of an ANM scheme, leads to a number of important learning points regarding the effect of energy storage. In particular the study notes that any investigation of ANM schemes must clearly define the objective of the scheme. It shows that secondary objectives such a maximising wind generation can lead to substantially different solutions compared with studies which focus on the primary objectives such as minimising costs or emissions associated with meeting demand.

The study highlights the importance of energy storage efficiency and shows that storage, when conducting price arbitrage, will only transfer energy between time-steps with a ratio of prices greater than the round trip efficiency.

The study shows that, to gain greatest benefit, energy storage must be operated as frequently as possible and that frequency of operation is more important that waiting for the greatest price uplift from any one charge/discharge cycle. This links to the need to operate energy storage so as to derive revenue from multiple revenue streams. In the case studied, price arbitrage and curtailment reduction are investigated and it is shown that the combination of the two can leads to greatest overall revenue.

The case study of Chapter 5 gives a detailed study of a simple network using DOPF. It shows the role of energy storage in managing real power flows at the grid connection point and internal to the distribution networks. A conclusion from this study is that energy storage can also use reactive power flow management and a method of reducing the cost of meeting demand.

The ability of DOPF to fully model network constraints and intertemporal effects is illustrated in the Chapter 5 case study. The location of energy storage and flexible demand is shown to be important, as the location affects network losses and the ability of the two technologies to manage congestion on particular lines within the distribution network.

Finally, the detailed analysis of the Shetland system in Chapter 7 applies the DOPF tools to a real ANM scheme that incorporates both energy storage and flexible demand. The conclusions of the study are that demand flexibility can, in the islanded context, be significantly more effective at managing wind generation curtailment than energy storage (although it is noted that energy storage brings other benefits).

8.2.2 The development of Dynamic Optimal Power Flow for Active Network Management

The framework presented in Chapter 5 for DOPF extends existing formulations to take account of principles-of-access, with priority order principles-of-access implemented in a case study. Chapter 3 identifies that existing models of energy storage do not fully model efficiency and full flexibility over charging and discharging. The model developed in Chapter 5 directly addresses these issues and removes the needs for pre-defining charging and discharging periods, whilst at the same time allowing charging and discharging efficiencies to be set to any value between 0 and 1. Chapter 5 also develops a model for flexible demand which has the same structure as that for energy storage.

As discussed above in Section 8.2.1, the development of DOPF allows the modelling of both network and intertemporal effects within a single formulation. This is important for understanding how energy storage and flexible demand should be operated, particularly at distribution level, as an important benefit which they bring is the management of thermal and voltage limits on the network.

8.2.3 The theory of Dynamic Locational Marginal Pricing

Chapter 3 notes that there is no literature which studies the economic information contained in solutions to DOPF problems. Chapter 6 develops a theory which fills this gap. The theory of DLMP is an extension of Locational Marginal Pricing, whereby prices at a particular bus and a particular time are given by Lagrangian multipliers on the nodal energy balance constraints. As DOPF treats intertemporal flexibility as branches in the network, it removes the need to define bidding strategies for intertemporal devices. Losses in energy storage, for example, are covered by the DMS. Instead, the economic information contained in the DLMPs form the basis of an economically efficient solution to the problem of dispatching generation and scheduling flexible demand and energy storage across time.

8.2.4 An operational application of DOPF to an islanded distribution network

Chapter 7 provides the first example of the application of DOPF to the development of a realistic ANM scheme. The Shetland Islands distribution network will contain energy storage and flexible demand controlled by a centralised ANM controller. The controller will carry out day-ahead scheduling of demand and generation based on measurements of the network and forecasts of generation and demand. Such a scheme requires a method of scheduling, and DOPF is used to study the system and produce results which are used to calibrate the scheduling software deployed on Shetland.

The DOPF developed in Chapter 5 and the DLMP theory developed in Chapter 6 are both applied to the Shetland network. Year-round studies are carried out for scheduling using a realistic future scenario. The work presented is important as it shows the adaptability and applicability of the DOPF method.

8.3 Future Work

The work presented in this thesis focuses on developing the models of energy storage and flexible demand and curtailing non-firm wind generation according to a principle-of-access. The work has also concentrated on solving cases for known wind generation and fixed demand situations. This lays the foundation for a number of further interesting research directions.

8.3.1. Integrating other Active Network Management technologies

The detailed modelling of voltage control in existing ANM schemes has been completed in the previous literature, as discussed in Chapter 3. The techniques used to model on load tap changing transformers and voltage regulators needs to be combined with the reactive dispatch of distributed generation and energy storage. Reactive dispatch and coordinated voltage control are non-intertemporal technologies in that their operation at one time does not affect operation at others - as such they have been developed in the OPF context without modelling across time-steps. The combination of the two should be straight forward and will allow a more complete model of distribution networks to be produced taking full account of the existing and potential future methods of managing voltage levels.

An important development will be the modelling of other technologies and techniques which are likely to be deployed to ANM schemes in the near future.

Dynamic Line Rating is a technique that involves varying the thermal limit on the lines to take account of the prevailing conditions [8.1]. Two forms of Dynamic Line Ratings can be identified: intertemporal and non-intertemporal.

Non-intertemporal ratings means defining the rating at a particular time depending on the exogenous conditions: wind speed; wind direction; temperature. Given a measurement of these conditions (or forecasts) the thermal limit can be defined using a physical model of the power line. During periods of high wind and low temperature, there is a significant cooling effect on the lines and the thermal limits can be raised; during calm, warm periods the thermal limits will be lowered. Including non-intertemporal Dynamic Line Ratings into a DOPF simply involves setting the thermal limit at different levels for each time-step. Such a method has already been used in the semi-intertemporal OPF presented in [8.2].

Intertemporal Dynamic Line Ratings involve taking account of power flows through a line over time and integrating the existing concept of short-term or emergency line ratings into normal operation. For example, a line usually rated at 10MVA can be operated with a greater power flow – for example 12MVA – for a short time as long as it is then operated at a lower rating – for example 8MVA – directly afterwards. Through the development of a physical model of a power line it is possible to define intertemporal relationships on power flows above and below the nominal rating of the line. These rules can be integrated into the DOPF framework to allow power flow through lines to be increased / decreased across the optimisation horizon.

8.3.2 Modelling uncertainty in wind and demand forecasts

For direct use in solving a day-ahead scheduling problem, DOPF needs to be able to take account of the issues associated with uncertainty in forecasts. In an operational situation it is not realistic to assume 'perfect foresight'.

A short initial study has been carried out using historic *measurements* of wind speed with historic *forecasts* of wind speed [8.3]. This uses forecasts of the wind and demand conditions for the coming 24 hours to schedule flexible demand and energy storage.

It then applies those schedules without change, in the face of the conditions that actually develop. Results suggest that savings on conventional generation are 65% of those that would have been achieved with perfect foresight across a 1-year period.

Whilst estimating the loss of optimality due to errors in the forecast, a useful analysis is to consider the uncertainty in wind forecasts directly within the optimisation tool. One potential method is Probabilistic Optimal Power Flow, which has been presented in a number of papers [8.4-8.6]. This attempts to take probability distributions as inputs to the Optimal Power Flow and produce probability distributions of the optimal outputs that include the objective function. Extending this to Dynamic Optimal Power Flow would allow the analysis of a particular optimal dispatch and give an indication of the distribution of likely effects on the objective function.

8.3.3 Developing Dynamic Locational Marginal Pricing

The concept of Dynamic Locational Marginal Pricing laid out in Chapter 6 and applied in Chapter 7 will be of use at transmission level as well as distribution level. The most obvious application is to networks which currently use Locational Marginal Pricing and include large-scale storage solutions such as pumped hydro storage.

The formulation should be extended to provide greater understanding of the relationship between shadow prices on power and energy constraints, storage efficiency and DLMPs. The role of merchandising surplus in covering the costs of losses should be investigated, as should the effect of introducing energy storage in changing the congestion part of DLMPs.

8.4 Summary

This thesis has presented the development of tools to assist in the analysis of second-generation Active Network Management schemes. It has provided a framework for the application of Dynamic Optimal Power Flow to Active Network Management. It has developed the theory of Dynamic Locational Marginal Pricing. Finally it has presented a detailed case study of the application of Dynamic Optimal Power Flow to a real Active Network Management scheme currently in development and deployment in the UK showing the applicability of the methods developed to industry.

8.5 References for Chapter 8

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Appendix 1: Mathematical formulation of optimisations

This appendix provides a summary of the formulation of the optimisations used in Chapter 4, 5 and 7. The details are discussed in the text of the relevant chapter. This appendix simply provides a recap of the formulation for ease of reference including a list of symbols. If the equation appears as part of the main text of the document, the equation numbers refer to those used in the original chapter.

A1.1 Linear programming optimisation of Chapter 4

Objective Function:

$$f = \max \Delta t \sum_{t=1}^{n_t} \left\{ \left(P^d(t) - P^c(t) \right) \pi(t) - P^{cc}(t)\, \pi_{curt}(t) \right\} \tag{4.4}$$

Network Constraints:

$$P^c(t) < P_{tcp}^{max} + P_{wind}(t) - P_{dem}(t)\ ;\ \forall t = 1,2, \dots n_t \tag{4.5}$$

$$P^d(t) < P_{tcp}^{max} - P_{wind}(t) + P_{dem}(t)\ ;\ \forall t = 1,2, \dots n_t \tag{4.6}$$

Limit on energy to store from curtailment:

$$0 < P^{cc}(t) < P_{curt}(t);\ \forall t = 1,2, \dots, n_t \tag{4.7}$$

Modelling the energy storage device:

$$0 < P^c(t) < P_{max}^c;\ \forall t = 1,2, \dots, n_t \tag{4.8}$$

$$0 < P^d(t) < \varepsilon_d P_{max}^d;\ \forall t = 1,2, \dots, n_t \tag{4.9}$$

$$0 < P^{cc}(t) < P^{c}_{max};\ \forall t = 1,2,\dots,n_t \tag{4.10}$$

$$P^{c}(t) + P^{cc}(t) < P^{c}_{max};\ \forall t = 1,2,\dots,n_t \tag{4.11}$$

$$0 < SOC_0 + \frac{\Delta t}{E^{cap}} \sum_{t=1}^{n} \left\{ \varepsilon_c (P^c(t) + P_{curt}(t)) - \frac{P^d(t)}{\varepsilon_d} \right\} < SOC_{max};\ t = 1..n_t \tag{4.12}$$

$$\sum_{t=1}^{n_t} \left\{ \varepsilon_c (P^c(t) + P^{cc}(t)) + \frac{P^d(t)}{\varepsilon_d} \right\} = 0 \tag{4.13}$$

The symbols used in this formulation are as follows:

f	Objective
Δt	Length of time-step
t	Time-step number
P^d	Discharge power of store during
P^c	Charging power of store from grid
P^{cc}	Charging power of store from curtailed wind during
π	Exogenous market price
π_{curt}	Price of curtailment (set to zero in this study)
SOC_0	Initial state of charge of energy store
P_{TCL}^{max}	Maximum power flow through grid supply point
P_{wind}	Total instantaneous base wind generation (without energy storage)
P_{dem}	Distribution network demand
n_t	Number of time-steps
P_{curt}	Base-line curtailment of wind (without energy storage)
P^{c}_{max}	Maximum rate of charge of energy storage
ε_c	Charging efficiency of energy store
ε_d	Discharging efficiency of energy store
SOC	State of charge: fraction of energy storage capacity in use
E^{cap}	Energy storage capacity.

SOC_{max} Maximum state of charge of energy storage

A1.2 Dynamic Optimal Power Flow formulation of Chapter 5

Two objectives representing minimise import and minimise cost of import:

$$f_1(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \min_{\boldsymbol{x}} \sum_{t=1}^{t_n} \left\{ \sum_{gcp=1}^{gcp_n} P_{gcp}(t) \right\} \tag{5.1}$$

$$f_2(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \min_{\boldsymbol{x}} \sum_{t=1}^{t_n} \left\{ \pi(t) \sum_{gcp=1}^{gcp_n} P_{gcp}(t) \right\} \tag{5.2}$$

Single time-step Optimal Power Flower formulation:

$$\boldsymbol{g}(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \mathbf{0} \; ; \; \forall t \tag{5.3}$$

$$V_{min}(b) < V(b,t) < V_{max}(b); \; \forall \, b, t \tag{5.4}$$

$$-S_{max}(l) < S(l,t) < S_{max}(l) \; ; \; \forall \, l, t \tag{5.5}$$

$$P_{gcp}^{min} < P_{gcp}(\,t) < P_{gcp}^{max}; \;\; \forall \, gcp, t \tag{5.6}$$

$$Q_{gcp}^{min} < Q_{gcp}(\,t) < Q_{gcp}^{max}; \;\; \forall \, gcp, \, t \tag{5.7}$$

Non-firm wind generation:

$$0 < P_g(nf,t) < P_g^{max}(nf,t); \quad \forall \, nf, t \tag{5.8}$$

Priority Order principle-of-access modification:

$$f_{\text{modified}} = f_{\text{obj}} + \delta_{\text{priority}} \tag{5.9}$$

$$\delta_{\text{priority}} = \sum_{t=1}^{t_n} \left\{ \sum_{nf=1}^{n_{nf}} \frac{p}{k} P_g(nf,t) \right\} \tag{5.12}$$

$$f_1(\boldsymbol{x}(t), \boldsymbol{y}(t), \boldsymbol{z}(t), \boldsymbol{\tau}(t)) = \min_{\boldsymbol{x}} \sum_{t=1}^{t_n} \left\{ \sum_{gcp=1}^{gcp_n} \left(P_{gcp}(t)\right) + \sum_{nf=1}^{nf_n} \frac{p}{k} P_g(nf,t) \right\} \tag{5.13}$$

Energy Storage Mode:

$$\Delta SOC = -\frac{\Delta t}{E_{store}^{cap}} \begin{cases} \varepsilon_c P_{store} & if\ P_{store} \geq 0 \\ \frac{1}{\varepsilon_d} P_{store} & otherwise \end{cases} \tag{5.16}$$

$$P_{store} = P_{store}^{d} + P_{store}^{c} \tag{5.17}$$

$$\left. \begin{array}{l} -P_{store}^{max}(t) < P_{store}^{c}(t) < 0 \\ 0 < P_{store}^{d}(t) < \varepsilon_d P_{store}^{max}(t) \end{array} \right\} \forall t \tag{5.18}$$

$$SOC_{store}(t) = SOC_{store}(0) - \frac{\varepsilon_c \Delta t}{E_{store}^{cap}} \sum_{t'=1}^{t} P_{store}^{c}(t') - \frac{\Delta t}{E_{store}^{cap} \varepsilon_d} \sum_{t'=1}^{t} P_{store}^{d}(t') \tag{5.19}$$

$$SOC_{store}^{min} < SOC_{store}(t) < SOC_{store}^{max};\ \forall\ t \tag{5.20}$$

$$SOC_{store}(0) = SOC_{store}(t_n) \tag{5.21}$$

$$S_{store}(t) < S_{store}^{rated}(t) \tag{5.23}$$

$$S_{store}(t) = \sqrt{{P_{store}}^2 + {Q_{store}}^2} \tag{5.24}$$

Flexible Demand Model:

$$\Delta \mathrm{t} \sum_{t=1}^{t_n} P_{FD}(t) = E_{FD} \tag{5.25}$$

$$P_{FD}^{min}(t) < P_{FD}(t) < P_{FD}^{max}; \forall\, t \tag{5.26}$$

$$SOC_{FD}(t) = SOC_{FD}(0) + \frac{\Delta t\, \mu}{F_{FD}^{cap}} \sum_{t'=1}^{t} P_{FD}^{c}(t') - \sum_{t'=1}^{t} F_{FD}(t') \tag{5.27}$$

$$SOC_{FD}(t) = SOC_{FD}(0) + \frac{\Delta t\, \mu}{E_{heat}^{cap}} \sum_{t'=1}^{t} P_{heat}^{c}(t') - \frac{\Delta t}{E_{heat}^{cap}} \sum_{t'=1}^{t} P_{heat}^{d}(t') \tag{5.30}$$

$$SOC_{FD}^{min} < SOC_{FD}(t) < SOC_{FD}^{max}; \forall\, t \tag{5.31}$$

$$SOC_{FD}(0) = SOC_{FD}(t_n) \tag{5.32}$$

Symbols used in this formulations

f_1, f_2	Objective functions
$\boldsymbol{x}, \mathbf{y}, \mathbf{z}, \boldsymbol{\tau}$	Control variable, Fixed parameters, derived variables and intertemporal variables
t, t_n, Δt	Time-step number, number of time-steps, length of 1 time-step
gcp, gcp_n	Grid connection point, number of grid connection points
$P_{gcp}(t)$	Real power import through grid supply point, *gcp*, during time-step *t*
$P_{gcp}(t)$	Reactive power import through grid supply point, *gcp*, during time-step *t*
$\pi(t)$	Exogenous market price during time-step *t*
b, b_n	Bus number, number of buses
$V_{min}(b), V_{max}(b)$	Maximum and Minimum voltage at bus *b*
$V(b,t)$	Voltage at bus *b* and time-step *t*
l, l_n	Circuit number, number of circuits
$S_{max}(l)$	Maximum apparent power through circuit *l*

$S(l,t)$	Apparent power through circuit *l* at time-step *t*
$P_{gcp}^{min}, P_{gcp}^{max}$	Maximum and minimum real power from grid connection point *gcp*
$Q_{gcp}^{min}, Q_{gcp}^{max}$	Minimum and maximum reactive power from grid connection point *gcp*
nf, nf_n	Non-firm wind farm number, number of non-firm wind farms
$P_g^{max}(nf,t)$	Maximum available (un-curtailed) generation from non-firm wind farm *nf* during time-step *t*
$P_g(nf,t)$	Scheduled generation at wind farm *nf* during time-step *t.*
f_{modified}	Modified objective function for priority principles of access
f_{obj}	Original (unmodified objective)
δ_{priority}	Small priority-order modification
p	Priority number
k	Priority order scaling constant
$SOC(t)$	Energy storage state of charge at time-step *t*
ΔSOC	Energy storage change in state of charge
$SOC_{store}^{max}, SOC_{store}^{min}$	Maximum and minimum limits on energy storage state of charge
E_{store}^{cap}	Energy storage energy capacity
$P_{store}\ (t)$	Net charge of energy storage measured at connection to grid
$Q_{store}\ \ (t)$	Reactive power drawn by store at connection to grid
ε_c	Charging efficiency of energy storage
ε_d	Discharging efficiency of energy storage
ε_{rt}	Round-trip efficiency of energy storage
P_{store}^{d}	Discharging component of energy storage (Positive when discharging)
P_{store}^{c}	Charging component of energy storage (Positive when charging)
P_{store}^{max}	Maximum rate of charge or discharge of energy storage
$S_{store}(t)$	Apparent power flow into store

$S_{store}^{rated}(t)$	Maximum limit on apparent power flow through energy storage power convertor
E_{FD}	Total energy demand from flexible demand unit
$P_{FD}(t)$	Power drawn by flexible demand unit during time-step *t*
$P_{FD}^{min}(t), P_{FD}^{min}(t)$	Minimum and Maximum power to be drawn by flexible demand unit during time-step *t*
$SOC_{FD}(t)$	State of charge of flexible demand unit
μ	Coefficient of performance (or efficiency) of flexible demand unit
$F_{FD}^{cap}, E_{FD}^{cap}$	Maximum storage of final product, for example maximum capacity of heat-energy storage
$P_{FD}^{c}(t)$	Power drawn from grid during time-step *t*
$F_{FD}(t)$	Underlying demand profile for final produce during time-step *t*
$P_{heat}^{d}(t)$	In heat storage, the underlying demand for heat during time-step *t*

A1.3 Modifications to the Dynamic Optimal Power Flow formulation presented in Chapter 7

The case study of Chapter 7 uses the general format of the DOPF framework presented in Chapter 5 and listed above in Section A1.2. The basic formulation is altered slightly to deal with the specific situation of an islanded distribution network. Additional limits are added to model the stability rules defined for system operation. The specifics of the formulation used in Chapter 7 are as follows:

Objective:

$$f = \min \sum_{t=1}^{t_n} \{P_{LPS}(t) + P_{SVT}(t)\} \tag{7.11}$$

Objective modified for priority order principles of access (Used for scheduling studies presented in Sections 7.4 - 7.7:

$$f_{modified} = \sum_{t=1}^{t_n} \left\{ \{P_{LPS}(t) + P_{SVT}(t)\} + \sum_{nf=1}^{nf_n} \frac{p}{1000} P_{nf}(t) \right\} \tag{7.12}$$

With p in the range 1-4 representing the 4 non-firm wind farms.

The single time-step formulation, non-firm wind limits, energy storage and flexible demand are modelled as given by equations (5.3) – (5.7), (5.8) and (5.16) – (5.32) respectively.

In addition three global stability rules are applied in the format:

$$\sum_{n=1}^{n_{firm}} \alpha_n P_{firm,n} + \sum_{m=1}^{n_{nf}} \beta_m P_{nf,m} + \sum_{p=1}^{n_{conv}} \gamma_p P_{conv,p} + \sum_{q=1}^{n_{frd}} \delta_p P_{frd,q} > \ \varepsilon \tag{7.1}$$

These three stability limits are:

1. **Operational Stability:**

$$0.8P_{total} - 3.6 > \ P_{wind} \tag{7.13}$$

Which in the format of (7.1) is written as:

$$\sum_{n=1}^{n_{firm}} -0.2P_{firm,n} + \sum_{m=1}^{n_{nf}} -0.2P_{nf,m} + \ 0.8P_{SVT} + \ 0.8P_{LSP} > \ \ 3.6 \tag{A1}$$

2. **Frequency Stability:**

$$0.44P_{total} + 3.1 > \ P_{wind} \tag{7.14}$$

Which in the format of (7.1) is written as:

$$\sum_{n=1}^{n_{firm}} -0.56P_{firm,n} + \sum_{m=1}^{n_{nf}} -0.56P_{nf,m} + \sum_{p=1}^{n_{conv}} 0.44P_{conv,p} > \ -3.1 \tag{A2}$$

When frequency-responsive demand is included, as discussed in Section 7.6.4 equations (7.11) and (A1) as discussed are extended as follows:

$$0.44P_{total} + 3.1 + 0.3P_{frd} > P_{wind} \tag{7.14}$$

Which in the format of (7.1) is written as:

$$\sum_{n=1}^{n_{firm}} -0.35P_{firm,n} + \sum_{m=1}^{n_{nf}} -0.35P_{nf,m} + 0.65P_{SVT} + 0.65P_{LSP} + \sum_{q=1}^{n_{frd}} 0.3\,P_{frd,q} > 3.6 \tag{A3}$$

3. Spinning reserve stability:

$$25 - P_{SVT} > P_{wind} \tag{7.15}$$

Which in the format of (7.1) is written as:

$$\sum_{n=1}^{n_{firm}} -1P_{firm,n} + \sum_{m=1}^{n_{nf}} -1P_{nf,m} - P_{SVT} > -25 \tag{A4}$$

Symbols used in the equations listed here are defined as follows

f, $f_{modified}$	Objective function, modified objective function
t, t_n	Time-step number, number of time-steps
$P_{LPS}(t)$	Power injections by Lerwick Power Station during time-step *t*
$P_{SVT}(t)$	Power injection by Sullom Voe Terminal during time-step *t*
p	Priority number of non-firm wind farm
$P_g(nf,t)$	Power injection by non-firm wind farm *nf* during time-step *t*
$\alpha, \beta, \gamma, \delta$	Stability rule coefficients on: firm wind, non-firm wind, conventional generation, frequency-responsive demand

ε	Stability rule constant
P_{total}	Sum of all generation from conventional and wind generation
$P_{firm,n}$	Power injection by firm wind farm n
$P_{nf,m}$	Power injection by non-firm wind farm m
$P_{conv,p}$	Power injection by conventional generation p
$P_{frd,q}$	Power demand by frequency-responsive demand unit q
P_{wind}	Sum of all firm and non-firm wind generation

Appendix 2: Summary of software developed to implement Dynamic Optimal Power Flow

During the process of developing the work presented in this thesis the author developed a Matlab-based code to work with Matpower [A2.1] – an existing open-source power system analysis suite. This appendix provides a brief summary of the software developed[13].

A2.1 Dynamic modelling for Matpower

Dynamic modelling Matpower is an implementation of an algorithm to solve some DOPF problems. It is built on the open-source Matlab program Matpower which provides an "extensible architecture" [A2.1] for OPF problems. Dynamic Modelling for Matpower consists of 10 core functions which encode a DOPF problem in a format suitable for solving via Matpower, the structure of the program is shown in Figure 76.

The Matpower suite of functions is able to solve Optimal Power Flow problems including those in which separate electrical islands form part of a single optimisation. Dynamic Modelling for Matpower makes use of this by creating an optimisation consisting of a separate electrical island for each time-step and by adding additional 'user defined constraints' [A2.2] to model the action of technologies which link operation of the power

[13] The source code will be made available on-line in open source form when practical.

system at different time-steps. In the current version, two technologies modelled are energy storage and flexible demand.

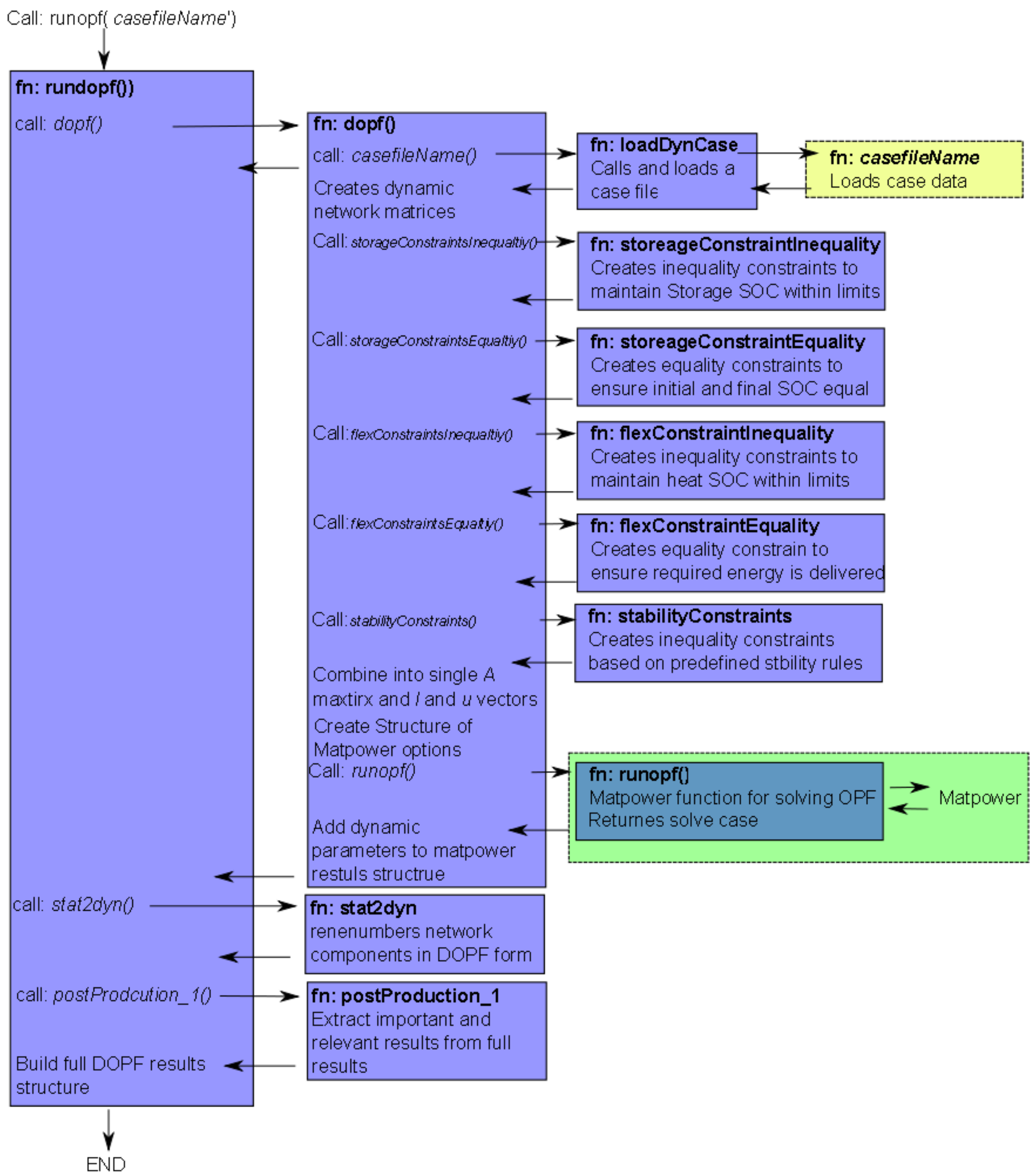

Figure 76: The structure of Dynamic Modelling for Matpower. Each box represents a function, and the whole structure calls Matpower through the runopf() Function belonging to Matpower.

The DOPF problem to be optimised is presented in a dynamic *casefile* which contains both the dynamic and static data. Dynamic data consists of: time-series of available generation and demand; parameters for energy storage and flexible demand; and the underlying demand profile for flexible demand. Static data for the network and network components is also included and follows the same format as a standard Matpower case file.

The following list is a brief description of the core Dynamic Modelling for Matpower functions shown in Figure 76.

Fn: *rundopf()*

This is a controlling function which initialises the optimisation and directs the post-processing of optimisation outputs.

Fn: *dopf()*

This is the key function which builds the problem into the required structure for Matpower to solve. It initially builds the standard Matpower matrices for generators, buses etc. Then it creates the additional constraints matrix A and the associated upper and lower bound vectors l and u. This is done in stages by calling a series of constraint functions (see below), these return their relevant constraints in a standard format that are combined to give a single constraint matrix. A Matpower options structure is created and used to control the solver used and the level of output to screen.

Fn: *storageConstraintInequality()*

Called from within *dopf()* this function uses the parameters for each storage device to create additional constraints to link the input and output generators of the device to a storage volume.

The constraints created ensure that during each time-step of the simulation the storage device must maintain its state of charge within the defined upper and lower bounds.

Fn: *storageConstraintEquality()*

In addition to the inequality constraints, a storage device is constrained to have the same initial and final state of charge. This is an equality constraint and is created in this function.

Fn: *flexConstraintInequality()*

The flexible demand has similar constraints to those for storage. This function creates the inequality constraints for each period required to maintain the state of charge of the flexible demand.

Fn: *flexConstraintEquality()*

The total energy supplied over the optimisation-horizon is fixed, this function creates the constraint to impose this.

Fn: *stabilityConstraints()*

Externally defined linear stability constraints form an input in the case file and are created here. This function can apply constraints such as: fractional minimums/maximum from particular generators or groups of generators, or where the limit from one generation type (e.g. wind) is a linear function of the output from other generation types or of storage or flexible demand.

Fn: *stat2dyn()*

Dynamic Modelling for Matpower solve the optimization by formulating the problem into a pseudo-Matpower network. The resulting output is not organised intuitively for a DOPF problem. This function rearranges the outputs into 3-D matrixes which, in 2 dimensions are similar to those from a standard Matpower OPF. The third dimension represents time-steps through the optimisation-horizon.

Fn: *postProcessing_1()*

The ordered result-set produced by *stat2dyn()* contains full network and component data. However, for the majority of studies there are a number of key results, such as the optimal schedule for energy storage to follow. This function extracts a number of key results from the ordered results and presents them as intuitively named fields in the *rundopf()* output structure. The function name contains *'_1'* at the end as it is expected that the function will be rewritten to take account of the exact study being performed – so a number of *postProcessing* functions are likely to exist in later versions of Dynamic Modelling for Matpower.

A2.2 Using Dynamic Modelling for Matpower

This section provides information on the encoding of DOPF problems into a Dynamic Modelling for Matpower *casefile*, how to call Dynamic Modelling for Matpower, and how to interpret the results that are returned.

A2.2.1 Install Matlab and Matpower

Matlab Release 2012a[14] and Matpower versions 4.1 should be installed before installing Dynamic Modelling for Matpower. Matpower is available to download from http://www.pserc.cornell.edu/matpower/ [A2.3] and detailed installation instructions are available in the user's manual [A2.2].

A2.2.2 Install Dynamic Modelling for Matpower

Add the Dynamic Modelling for Matpower functions to a file and ensure that this file is on the Matlab path.

A2.2.3 Create a Dynamic Modelling for Matpower CaseFile

The structure of a case file can be described in three sections:

[14] Earlier versions of Matlab will in general work, although a number of the Matlab commands used use syntax specific to versions from 2012 onwards. Minor adjustments to the Dynamic Modelling for Matlab code may be required to work with earlier releases of Matlab.

The Matlab function

The *casefile* is a Matlab function and must be structured in the correct Matlab syntax.

Dynamic time-series information

The dynamic information contains the parameters for the time-stepping of the optimisation, wind farms parameters, energy storage, flexible demand and stability constraints. It also loads the time-series information for available wind generation, and for fixed and flexible electrical demand.

Static network information

The static information contains the parameters for the network, generation and peak fixed demand at each bus. The static part of a Dynamic Matpower case file is identical to the format of a standard Matpower case file.

The following code listing gives an example test network containing: 2 buses generation, fixed demand, a single electrical circuit, energy storage and flexible demand:

```
function [mpd mps] = simpleDLMPexample()
% Simple 2 bus, 24 time-step example of DLMP
%

%% Time-series Data

mpd=load('dlmpExampleWind');

mpd.delta_t = 1; %Length of each time period (hrs)

%% Wind Generator Data
% Bus   Rated-Capacity(MW) Curtailable(0==no; 1==yes) Priority pf
(0==fixed, 1==variable) min_pf max_pf
mpd.wind = [
    1    15       0    0    0    1    1    0    0; %Firm Wind Farm
    2    10       1    1    1    1    0.95 1    0; %non-firm Wind Farm
];

%% Storage Data
% Bus    E_cap(MWh)   Pin_max(MW)      Pout_max(MW)    E_initial(MWh)
Eff_in Eff_out
mpd.store = [
   1    10    1   1     5    sqrt(0.7) sqrt(0.7) ;
];

%% Flexible Demand
```

```
% Bus    E_cap(MWh)    Pin_max(MW) Pout_capacity(MW) E_initial(MWh)
lossRate(MW) Profile
mpd.flex = [
 1     100  10    10    50   0    1 ;
];

%% Stability Constraints

mpd.stability = [
  0.5    0.5
    ];

%% MATPOWER Case Format : Version 2
mps.version = '2';

%%-----  Power Flow Data  -----%%
%% system MVA base
mps.baseMVA = 100;

%% bus data
%   bus_i   type    Pd      Qd      Gs      Bs      area    Vm      Va
baseKV  zone    Vmax    Vmin
mps.bus = [
1   3   15  0   0   0   1   1   0   33  1   1.1 0.9;
2   1   15  0   0   0   1   1   0   33  1   1.1 0.9;
];

%% generator data
%   bus Pg      Qg    Qmax   Qmin    Vg    mBase status  Pmax
Pmin
mps.gen = [
1       0    0    2.4  -2.4   1  1  1 50;
2       0    0    2.4  -2.4   1  1  1 50;
];

%% branch data
%   fbus    tbus    r   x   b   rateA   rateB   rateC   ratio   angle
status  angmin  angmax
mps.branch = [
1    2    0.1 0.1 0   11 11 11   1 0 1  -360  360;
];

%%-----  OPF Data  -----%%
%% generator cost data
%   1   startup shutdown    n   x1  y1  ... xn  yn
%   2   startup shutdown    n   c(n-1)  ... c0
mps.gencost = [
2   1   0   3   0   10  0;
2   0   0   3   0   10  0;
];
```

The full details of the format of a CaseFile for Dynamic Modelling for Matpower are given in the Matlab script file *dynCaseFormat.m:*

```
DYN_CASEFORMAT describes the case file format for a dynamic OPF case to
be solved by rundopf. The rundopf function is a wrapper function that
used Matpower to solve
multi-period OPF solution.

Version info:
    Created by: Simon Gill
    Contact: simon.gill@strath.ac.uk
    Created: 06 December 2011
    Last Edited: 23th September 2013
    Version: Part of Dynamic Modelling for Matpower 1.7

Time-series Data for wind and demand

  mpd=load('dopfTest');

  Loads  a .mat data file containing three time-series data sets
    -- dem_data      : time-series of normalised fixed demand. This
                       should contain 1 time-series. All fixed demand
                       will follow the same profile.
    -- gen_data      : time-series of normalised renewable generation:
                       Should contain 1 time-series. All firm and non-
                       firm wind generation will follow the same
                       profile
    -- flex_dem_data : UN-NORMALISED time-series of the demand i.e. the
                       output from the flexible demand devices. This
                       can contain more than 1 profile, and the
                       flexible demand section (below) will refer to
                       the profiles in the order in which they appear.
                       If there are differences in the length of the
                       three time-series an error will be displayed.
                       NOTE the program assumes that there are more
                       time-steps in the optimisation than there are
                       different flex_dem_data profiles so that the
                       long dimension of the array represents time and
                       the short axis different profiles.

     -- price       :  Time-series of exogenously defined market price
                       representing the cost of import during each
                       time-step. This is only required is the
                       objective 'minimise cost of import' is being
                       used.

 Wind Generation Data: Contains details of the capacity of wind (or
            other renewable) generation
    -- Bus            :Bus number of the base case network at which the
                       wind farm is connected.
    -- Rated-Capacity :MW capacity of the wind farm
    -- Curtailable?       1 == Farm can be curtailed - it has a non-
                               firm connection
```

```
                          0 == Farm cannot be curtailed - firm
                               connection will be treated as -ive
                               demand by the optimisation
    -- Priority          :Applies to non-firm farms: The optimisation uses
                          Last-in-first-out principle-of-access number the
                          generators in order of their priority. This will
                          be ignored for firm-connected farms

 Storage Data: Details of the storage devices included:

    --Bus                : Network bus to which the device is connected
    --E_cap(MWh)         : Maximum energy stored capacity
    --Pin_max(MW)        : Maximum grid side rate of charge
    --Pout_max(MW)       : Maximum grid side rate of discharge
    --E_initial(MW)      : Initial SOC of the device
    --Eff_in             : Fractional Charging efficiency
    --Eff_out            : Discharging efficiency
                           The product of Eff_in and Eff_out is the round
                           trip efficiency


Flexible Demand: Details of the Flexible demand devices:
   --Bus                 : Network bus to which the device is connected
   --E_cap(MWh)          : Maximum energy stored in the devices
   --Pin_max(MW)         : Maximum rate of charge to device
   --Pout_max(MW)        : DEPRETIATED: Maximum rate of discharge.
                         Currently this is unused and is set by the time-
                         series provided earlier.
   --E_initial (MWh)     : Initial state of charge of the device
   --loss rate (MW)      : Rate of energy loss from stored devices
   --Profile             : The profile to choose from those provided in
                         the time-series data above

Stability Rules: Linear equations relating to maximum wind capacity
that can generate at any time.
   --a_1... a_n_en        : Length n_gen : coefficient for each generator
                            defined in the static case
   --b_1 ... b_n_nf       : Length n_nf  : coefficient for each non-firm
                            farm defined above in Wind Generation Data
   --c_1 ... c_n_ess      : length n_ess : coefficients for the charging
                            of component of each ESS
   --d_1 ... d_n_ess      : length n_ess : coefficients for the
                            discharging of component of each ESS
   --e_1 ... e_n_fd       : length n_fd : coefficient for each Flexible
                            demand unit
   --f_firm               : length 1: A single coefficient to be applied
                            to all non-firm wind farms : length 1: A
                            single numerical offset
   --g                    : constant coefficient

        The resulting equation is as follows:

        a.P(Gen) + b.P(nf) + c.P(ess_charge) + d.P(ess_discharge) +
                      e.P(fd) +    > - sum(f*P(firm))+ g
```

```
      where '.' represents the dot product.

Static Matpower case
      This is identical to the static Matpower case for Matpower V1.4
      it can either call a matpower case its self or include the
      information directly here. For details on the structure of a
      matpower case see CASEFORMAT in the Matpower distribution.
```

A2.2.4 Objective of the Dynamic Modelling for Matpower Optimisation

Currently two objectives can be coded into Dynamic Modelling for Matpower: minimise the use of conventional generation (or minimise import from an external network when considering a distribution network with renewable generation); and minimise *cost* of generation or import. In future versions it is expected that there will be an ability to choose or set objectives.

The objective of minimise conventional generation is applied as follows:

1. The cost of conventional generation or import is set 'high' in the *casefile* under 'Generator Cost Data' at the end of the static section. The following lines of the *casefile* define the cost of the one generator in the *testNetwork:*

```
%% Generator Cost Data
%   model   Start-up    Shutdown    n   x1   y1   y2
mps.gencost = [
    2    0    0    3    0    1      0 ;
];
```

   This describes a polynomial model or order 3 (quadratic) with the coefficients 0, 1, 0 or the equation: c=*1.p* where *c* is cost and *p* is power generated. If more than 1 generator exists this line should be repeated once for each generator. This gives all conventional generation an equal cost.

2. In *loadDynCase()* the cost of non-firm wind generation is set via the line:

```
dCase.wind_curt_cost(i,:)=[2 0 0 3 0 0.001*i 0];
```

Where the numbers in the vector follow the same format as those in the *casefile* lines above. This sets the non-firm generation to have a significantly lower cost than conventional generation. In addition it applies a priority order to the non-firm generators. The cost of the highest priority generator is *c=0.001P* whilst the cost of the next one is *c=0.002P* and so on.

Applying the objective of minimising the cost of generation means setting the quadratic coefficients of the generator cost curves to realistic values.

Finally, applying the objective of minimising the cost of import means setting the linear coefficient on the generator cost curves. To apply this objective a price time-series forms an input in the *caseFile*.

A2.2.5 Coding network stability rules

Network stability rules refer to any inter-relationship between the outputs of different generators, they can fulfil a number of functions. In Dynamic Modelling for Matpower they are formatted in line with the Dynamic Modelling for Matpower standard format for additional linear constraints. This is of the form:

$$\boldsymbol{l} < \boldsymbol{A} < \boldsymbol{u}$$

where l is the vector of lower limits, u is the vector of upper limits and A is the matrix of linear coefficients. The Dynamic Modelling for Matpower formulation follows this format but only uses the lower bound, setting the upper bound to infinity. This does not reduce generality as a constraints bounded on both sides can be formulated as two separate constraints.

The general format of the inequality constraint to be entered is as follows:

$$\begin{bmatrix} a_1 \\ \vdots \\ a_{n_g} \end{bmatrix} . \begin{bmatrix} P_{g_1} \\ \vdots \\ P_{g_{n_g}} \end{bmatrix} + \begin{bmatrix} b_1 \\ \vdots \\ b_{n_{nf}} \end{bmatrix} . \begin{bmatrix} P_{nf_1} \\ \vdots \\ P_{nf_{n_g}} \end{bmatrix} + \begin{bmatrix} c_1 \\ \vdots \\ c_{n_{ess}} \end{bmatrix} . \begin{bmatrix} P_{ess\,(charge)_1} \\ \vdots \\ P_{esss(charge)_{n_g}} \end{bmatrix} + \begin{bmatrix} d_1 \\ \vdots \\ d_{n_{ess}} \end{bmatrix} . \begin{bmatrix} P_{ess\,(dis.)_1} \\ \vdots \\ P_{esss(dis.)_{n_g}} \end{bmatrix} + \begin{bmatrix} e_1 \\ \vdots \\ e_{n_{ess}} \end{bmatrix} . \begin{bmatrix} P_{fd_1} \\ \vdots \\ P_{fd_{n_g}} \end{bmatrix} > -f \sum_{i=1}^{n_{firm}} P_{firm_i} + g$$

Where the left hand side is **A** and the right hand side is $\boldsymbol{l}$.

Coefficients $a - g$ should be entered in the stability rules matrix of the case file in the order: $[\, a_1 \,..\, a_{n_g}, b_1 \,..\, b_{n_{nf}}, etc]$. If a particular type of device is not included it is simply left out of the coefficients. If too many coefficients are entered an error message will be shown. There should be:

- 1 coefficient per conventional generator
- 1 coefficient per non-firm wind farm
- 2 coefficients per Energy storage device (ordered by: all coefficients for charging each Energy storage device followed by coefficients for discharging each Energy storage device)
- 1 coefficient per flexible demand unit
- 1 coefficient only representing all firm wind farms
- 1 constant

Examples of stability rules

- *Wind offset by conventional generation*

As a simple example consider a network with two conventional generators, non-firm wind and no Energy storage device or flexible demand. If network stability studies have shown wind generation must always be offset by an equivalent generation at generator 1 and generator 2 has a predefined minimum of 5MW:

$$0.5P_1 + 5 > P_{nf}$$

This can be rearranged into the correct order:

$$0.5P_1 - P_{nf} > -5$$

Using the format defined, this would be implemented by defining the stability rule in the *caseFile* as:

$$[\, 0.5 \;\; 0 \;\; 1 \;\; -5;]$$

This states that the maximum wind is 50% of the output of generator 1 with the fixed minimum from generator 2 being subtracted as a constant.

The format can also be used to apply other minimum / maximum dispatch constraints. For example, in the above example if generator 1 is always to cover 40% of all generation:

$$P_1 > 0.4(P_1 + P_2 + P_{nf})$$

Rearranged to give:

$$0.6P_1 - 0.4P_2 - 0.4P_{nf} > 0$$

or in the Dynamic Modelling for Matpower stability rule format rearranged to give:

$$[-0.6 \;\; 0.4 \; 0.4 \;\; 0;]$$

Multiple stability constraints can be included and the two in the example above would be combined to give the stability constraint matrix:

```
mpd.stability = [
0.5   0   1      -5;
-0.6      0.4   0.4   0;
];
```

A2.2.6 Calling Dynamic Modelling for Matpower

To call dynamic modelling for matpower create and save the CaseFile. To run Dynamic Modelling for Matpower use the following command:

```
dSolution = rundopf('CaseFile');
```

Do not include the '.m' extension on the CaseFile name; the single quote marks are required.

The program will return a Matlab structure with the following key components:

`dSolution.full_unordered`	This is the raw solution of the function 'runopf()' within Matpower itself. The numbering of buses,

	generators etc does not reflect the context of DOPF and are difficult to interpret.
`dSolutoin.full_ordered`	This represents the output of the Dynamic Modelling for Matpower function 'stat2dyn()' in which the raw Matpower results are reordered into a more intuitive format. All scheduling data is maintained.
`dSolution.processed`	This represents the output of the Dynamic Modelling for Matpower function 'postProcessing_1()'. Key results relevant to studies in energy storage and flexible demand such as charging / discharging scheduled are presented in a simple format.

A2.2 References for Appendix 2

[A2.1] R. D. Zimmerman, C. E. Murillo-Sanchez, and R. J. Thomas, MATPOWER: Steady-State Operations, Planning, and Analysis Tools for Power Systems Research and Education, *Power Systems, IEEE Transactions on*, vol. 26, pp. 12-19, 2011.

[A2.2] R. D. Zimmerman, C. E. Murillo-Sanchez, *Matpower 4.1 User's Manual,* 2011. Available at: http://www.pserc.cornell.edu/matpower/manual.pdf, accessed: 15/01/2014.

[A2.3] R. D. Zimmerman, C. E. Murillo-Sanchez, D. Gan, *MATPOWER A MATLAB Power Simulation Package, homepage.* Available at: http://www.pserc.cornell.edu /matpower/, accessed: 23/09/2013.

Appendix 3: Exemplar data for modelling Shetland

As noted in Chapter 7, much of the data used as inputs to the detailed modelling of the Shetland system is currently covered by commercial sensitivity or forms part of ongoing and unpublished academic research being performed by other members of the modelling team. The details provided in Chapter 7 are intended to allow the interested reader to reproduce the methodology using similar data.

This appendix provides raw input data for a single day – the 12th June to show the data and format required for the modelling. Fixed demand is normalised by its peak value; wind generation is normalised by installed capacity; and flexible demand is normalised by the peak underlying demand profile.

Time-step	Start (hh:mm)	Finish (hh:mm)	Normalised fixed demand	Normalised wind generation	Normalised Underlying Flexible Demand
1	00:00	00:15	0.35	0.19	0.17
2	00:15	00:30	0.35	0.22	0.15
3	00:30	00:45	0.34	0.30	0.15
4	00:45	01:00	0.33	0.43	0.16
5	01:00	01:15	0.34	0.55	0.14
6	01:15	01:30	0.34	0.44	0.15
7	01:30	01:45	0.34	0.47	0.16
8	01:45	02:00	0.33	0.63	0.15
9	02:00	02:15	0.34	0.78	0.15
10	02:15	02:30	0.33	0.54	0.15
11	02:30	02:45	0.31	0.64	0.19
12	02:45	03:00	0.30	0.66	0.16
13	03:00	03:15	0.31	0.68	0.16
14	03:15	03:30	0.33	0.72	0.16
15	03:30	03:45	0.32	0.74	0.17
16	03:45	04:00	0.30	0.73	0.16
17	04:00	04:15	0.31	0.86	0.17
18	04:15	04:30	0.33	0.90	0.15
19	04:30	04:45	0.32	0.86	0.16

Time-step	Start (hh:mm)	Finish (hh:mm)	Normalised fixed demand	Normalised wind generation	Normalised Underlying Flexible Demand
20	04:45	05:00	0.30	0.90	0.16
21	05:00	05:15	0.32	0.92	0.15
22	05:15	05:30	0.35	0.92	0.15
23	05:30	05:45	0.36	0.87	0.17
24	05:45	06:00	0.34	0.89	0.19
25	06:00	06:15	0.35	0.97	0.26
26	06:15	06:30	0.37	0.92	0.44
27	06:30	06:45	0.37	0.94	0.61
28	06:45	07:00	0.36	0.95	0.75
29	07:00	07:15	0.35	0.95	0.84
30	07:15	07:30	0.35	0.95	0.93
31	07:30	07:45	0.37	0.95	1.00
32	07:45	08:00	0.38	0.95	0.87
33	08:00	08:15	0.39	0.95	0.83
34	08:15	08:30	0.40	0.95	0.82
35	08:30	08:45	0.39	0.96	0.88
36	08:45	09:00	0.39	0.96	0.84
37	09:00	09:15	0.38	0.95	0.79
38	09:15	09:30	0.38	0.90	0.72
39	09:30	09:45	0.38	0.78	0.71
40	09:45	10:00	0.38	0.75	0.70
41	10:00	10:15	0.40	0.79	0.70
42	10:15	10:30	0.43	0.80	0.68
43	10:30	10:45	0.41	0.78	0.66
44	10:45	11:00	0.38	0.70	0.72
45	11:00	11:15	0.38	0.70	0.76
46	11:15	11:30	0.37	0.68	0.78
47	11:30	11:45	0.40	0.73	0.68
48	11:45	12:00	0.40	0.78	0.65
49	12:00	12:15	0.40	0.80	0.66
50	12:15	12:30	0.40	0.67	0.67
51	12:30	12:45	0.41	0.78	0.69
52	12:45	13:00	0.43	0.72	0.63
53	13:00	13:15	0.43	0.78	0.60
54	13:15	13:30	0.43	0.62	0.66
55	13:30	13:45	0.42	0.56	0.72
56	13:45	14:00	0.42	0.65	0.73
57	14:00	14:15	0.41	0.67	0.68
58	14:15	14:30	0.39	0.75	0.68
59	14:30	14:45	0.40	0.69	0.66
60	14:45	15:00	0.40	0.62	0.65
61	15:00	15:15	0.39	0.49	0.65
62	15:15	15:30	0.39	0.63	0.72
63	15:30	15:45	0.41	0.78	0.70
64	15:45	16:00	0.39	0.64	0.68

Time-step	Start (hh:mm)	Finish (hh:mm)	Normalised fixed demand	Normalised wind generation	Normalised Underlying Flexible Demand
65	16:00	16:15	0.40	0.68	0.67
66	16:15	16:30	0.41	0.59	0.70
67	16:30	16:45	0.42	0.68	0.68
68	16:45	17:00	0.43	0.55	0.56
69	17:00	17:15	0.43	0.57	0.53
70	17:15	17:30	0.42	0.41	0.55
71	17:30	17:45	0.43	0.55	0.56
72	17:45	18:00	0.43	0.40	0.50
73	18:00	18:15	0.43	0.28	0.52
74	18:15	18:30	0.43	0.23	0.50
75	18:30	18:45	0.41	0.28	0.39
76	18:45	19:00	0.40	0.34	0.40
77	19:00	19:15	0.37	0.22	0.43
78	19:15	19:30	0.35	0.19	0.47
79	19:30	19:45	0.34	0.28	0.45
80	19:45	20:00	0.33	0.18	0.55
81	20:00	20:15	0.35	0.13	0.74
82	20:15	20:30	0.35	0.22	0.66
83	20:30	20:45	0.37	0.20	0.64
84	20:45	21:00	0.36	0.17	0.66
85	21:00	21:15	0.36	0.05	0.71
86	21:15	21:30	0.37	0.08	0.76
87	21:30	21:45	0.36	0.08	0.73
88	21:45	22:00	0.35	0.11	0.70
89	22:00	22:15	0.34	0.07	0.70
90	22:15	22:30	0.34	0.16	0.70
91	22:30	22:45	0.33	0.10	0.68
92	22:45	23:00	0.33	0.16	0.66
93	23:00	23:15	0.34	0.11	0.51
94	23:15	23:30	0.35	0.17	0.33
95	23:30	23:45	0.36	0.19	0.22
96	23:45	00:00	0.36	0.20	0.19