An analysis of the UK regulatory and market frameworks for network access to develop enduring arrangements for a low-carbon power system

A thesis submitted to

University of London

For the degree of Doctor of Philosophy

by

Charlotte Ramsay

Imperial College London

Centre for Environmental Policy

September 2007

Declaration

This is to certify that:

1. No part of the work referred to in this thesis has been presented in support of an application for another degree or qualification in this or any other University

2. This thesis is less than 100,000 words in length excluding References.

Charlotte Ramsay

Abstract

Power networks connecting demand and generation are an essential component of a competitive market in the electricity sector, with cost reflective network access being critical for facilitating competition in generation and supply. In the current climate, where energy policy is being driven by the low-carbon agenda, market-based incentives to promote a sustainable power sector have resulted in over 20GW of new wind generation (both on and offshore) awaiting connection to the UK network. This development, along with increasing penetration of smaller scale generation in the distribution network is driving a radical change in the UK generation mix and the way the networks are used.

This thesis begins by exploring the impact of these new generators on network access using an interdisciplinary approach to expose the fundamental economics of the new and existing system. In the new system network access requirements are altered by an increased generation capacity margin. Under these conditions, it is no longer economically efficient to invest in sufficient network capacity to accommodate simultaneous peaks from all generators. As such, the critical finding of this study is that conventional and non-conventional generation should share network capacity.

Following this, a critical analysis of the existing technical, market and regulatory framework was conducted to evaluate whether it is capable of recognising these differences demonstrated in the new system. The evaluation found that although the current framework is appropriate for the incumbent system, it is a major barrier for the cost effective integration of non-conventional generation technologies in the operation and development of the network.

Finally, the thesis presents and evaluates alternative options for the development of enduring transmission access arrangements for a future low-carbon system within the UK market environment, and explores a technical architecture to facilitate transmission network access for distributed generation and demand resources.

Table of Contents

CHAPTER 1: Introduction 13

1.1 Background 13

1.2 Overview of the current network access arrangements 14

1.3 Network access to facilitate competition 16

1.4 Implications of non cost reflective access arrangements 18

1.5 Research question, aims and objectives 21

1.6 Scope and methodology 23

1.6.1 Scope of the research 23
1.6.2 Overarching approach: Whole system analysis 25
1.6.3 Research methodologies 26
1.6.4 Contribution and originality of the research 28

1.7 Structure of the thesis 30

CHAPTER 2: Network operation and development and challenges for the transition to a future sustainable power system 31

2.1 Introduction 31

2.2 Overview of the conventional and future power system 32

2.2.1 Conventional system architecture and characteristics 32
2.2.2 Drivers for change 38
2.2.3 Future system architecture and driving factors to challenge the current system 40
2.2.4 Materiality of the changes to the UK generation mix and demand 44

2.3 Network access: Alternatives for investment and pricing 46

2.3.1 Overview of cost reflective charging for network access 46
2.3.2 Long-run versus short-run marginal pricing of network access 47

2.4 Transmission network access 48

2.4.1 Transmission network long term access: design and investment 48
2.4.2 Regulatory arrangements and charging for long term access: system reinforcement costs 54
2.4.3 Transmission network short term access: constraint management 56
2.4.4 Regulatory arrangements and charging for short term access: allocation of constraint costs 58
2.4.5 Challenges to transmission network operation and development from transmission connected renewable generation 59

2.5 Distribution network access 60

2.5.1 Distribution network long term access: network design, security standards and investment 61
2.5.2 Regulatory arrangements and charging for long term access: Distribution Use of System charges 67
2.5.3 Challenges to distribution network operation and development from distributed generation 68

2.6 Conclusions and implications 71

CHAPTER 3: Network costs and benefits of renewable and of distributed generation 75

3.1 Introduction 75

3.2 Impact assessment methodology 76

3.2.1 Definition of operational and investment timescales 76
3.2.2 Drivers of non-conventional generation impact on the network 78
3.2.3 Impact assessment matrix 82

3.3 Transmission impact assessment 83

3.3.1 Introduction 83
3.3.2 Transmission operation: Constraints 83
3.3.3 Transmission investment: Capacity requirements for wind 88
3.3.4 Summary and conclusions 100

3.4 Distribution impact assessment 101

3.4.1 Introduction: 101

3.4.2 *Distribution network operation* ... 101
3.4.3 *Distribution network investment* ... 109
3.4.4 *Summary and Conclusions* ... 113

3.5 Implications and Conclusions ... 114

CHAPTER 4: Transmission network access arrangements for systems with renewable and distributed generation ... 117

4.1 Introduction ... 117

4.2 Evaluation of the current transmission access arrangements ... 118

4.2.1 *Characteristics of transmission access requirements for wind, DG and demand* ... 119
4.2.2 *Access requirements for distributed generation and demand* ... 120
4.2.3 *Recap of the current transmission access arrangements* ... 121
4.2.4 *Evaluation of the current access arrangements for systems with wind* ... 123
4.2.5 *Implications of current market and regulatory arrangements for wind access* ... 129
4.2.6 *Evaluation of current transmission access arrangements for distributed generation and demand* ... 130
4.2.7 *Implications of propagating the TEC-based approach to transmission access for distributed generation and demand* ... 134
4.2.8 *Conclusions and implications of the evaluation* ... 137

4.3 Framework for universal arrangements for transmission access ... 138

4.3.1 *Requirements for future transmission arrangements* ... 138

4.4 Comparative framework for assessment of future transmission access arrangements ... 142

4.4.1 *Invest then connect & predict costs* ... 144
4.4.2 *Connect and manage and observe system costs* ... 145
4.4.3 *Competitive Market Philosophy: Ex-post spot pricing* ... 146

4.5 Summary of options for future transmission arrangements ... 150

4.6 Conclusions on options for new enduring access arrangements ... 153

CHAPTER 5: Technical architecture to facilitate transmission access for DG and demand ... 155

5.1 Introduction ... 155

5.2 The Virtual Power Plant ... 156

5.3 Characterising the VPP ... 158

5.3.1 *Commercial VPP activity* ... 160
5.3.2 *Technical VPP activity* ... 162
5.3.3 *Interaction between CVPP and TVPP* ... 166

5.4 Representation and the role of the agent ... 168

5.5 Conclusions on developing transmission network access for DG ... 169

CHAPTER 6: Discussion, conclusions and further work ... 171

6.1 Discussion ... 171

6.1.1 *Summary of findings* ... 171
6.1.2 *Changing roles in transmission network access* ... 172
6.1.3 *Changing roles in distribution network access* ... 175
6.1.4 *The growing role of the demand side in network access* ... 179

6.2 Conclusions and recommendations ... 180

6.2.1 *Response to research questions* ... 180
6.2.2 *Final conclusions and recommendations* ... 182

6.3 Critique of the thesis and proposals for further work ... 185

6.3.1 *Limitations of the approach* ... 185
6.3.2 *Suggestions for development of key findings* ... 189

References ... 193

List of Figures

Chapter 1:

Figure 1-1: Value chain for electricity from central generation to LV distribution 17

Figure 1-2: Relative levels of system capacity under location/TOU-specific and non-locational/TOU network access arrangements 19

Figure 1-3: Whole system analysis approach 25

Figure 1-4: Increasing penetration of renewables and DG, and transitions in market and regulatory arrangements driving forward the evolution of the low-carbon system 26

Chapter 2:

Figure 2-1: Schematic of the conventional power system 32

Figure 2-2: Breakdown of generation capacity in the UK by MWe and percentage share (DTI, 2006a)..... 33

Figure 2-3: Summer and winter daily demand profiles in 2005/06 (NGET, 2007a) 37

Figure 2-4: Load coincidence factor as a function of number of customer households (Strbac, 2006) 37

Figure 2-5: Schematic of the future sustainable power system based on transmission connected renewables and distributed generation 41

Figure 2-6: Optimal balance between transmission investment and operating cost 50

Figure 2-7: Example two-busbar system and calculation of system risk imposed by transmission capacity 53

Figure 2-8: Operation of the UK Electricity Market during a single Settlement Period (NGET, 2007a) 57

Figure 2-9: ER P2/6 restoration time philosophy relative to peak network demand/network voltage level. 63

Chapter 3:

Figure 3-1: Total Demand and Installed/Utilised Generation (GW) in UK for 2006/07 and forecast for 2012/13 (NGET, 2007a) 80

Figure 3-2: Simplified 2 busbar example of the GB system illustrating the England-Scotland transmission connection 86

Figure 3-3: Simplified Great Britain (GB) transmission system 89

Figure 3-4: Normalized wind output for diverse and non-diverse wind sources (Ilex and Strbac, 2002) 91

Figure 3-5: Capacity of conventional plant that can be displaced by wind generation (Strbac et al., 2007). 92

Figure 3-6: 2 bus-bar example illustrating the methodology for determining transmission capacity requirements driven by reliability in systems with varying penetration wind 93

Figure 3-7: Transmission capacity requirements for the system with diverse wind generation resources.. 94

Figure 3-8: Transmission capacity requirements for the system with non-diverse wind generation resources 94

Figure 3-9: Correlation between losses and system load for (a) rural and (b) urban areas (Cao et al., 2006) 105

Figure 3-10: Normalised μCHP output during winter (Cao et al., 2006) 106

Figure 3-11: Normalised PV output profiles (Jenkins, 1995) 107

Figure 3-12: Contribution of μCHP and PV on the reduction in distribution network losses in (A) Rural areas and (B) Urban areas (Cao et al., 2006) 108

Figure 3-13: Example of secure network design without generation contributions 109

Figure 3-14: Network (A) and non-network (B) solutions to a distribution network security of supply shortfall. 110

Figure 3-15: Contribution of μCHP on the demand for network capacity (Cao et al., 2006) 112

Chapter 4:

Figure 4-1: Example 2-bus system with conventional & wind generation sharing transmission capacity . 125

Figure 4-2: Options for future transmission access arrangements 142

Chapter 5:

Figure 5-1: Characterisation of distributed generation (G) and demand (L) at various voltage levels in the Distribution Network as a Virtual Power Plant 158

Figure 5-2: Inputs to- and output from CVPP activity 161

Figure 5-3: Inputs to-and outputs from TVPP activity 162

Figure 5-4: UK Generic EHV voltage model (DG&SEE, 2007) mapping to a single VPP PQ characterisation 163

Figure 5-5: PQ characteristic of the TVPP 164

Figure 5-6: Bid-offer ladder from the TVPP 165

Figure 5-7: Commercial and Technical VPP activity in energy market and system management context 166

List of Tables

Chapter 2:

Table 2-1: Generation capacity installed in the UK distribution networks (DTI, 2006b) 34

Table 2-2: Projected increase in generation and demand in the 14 demand zones across the UK (Ofgem, 2006b) 45

Table 2-3: F factors in % for non-intermittent generation 64

Table 2-4: F factors in % for intermittent generation 64

Chapter 3:

Table 3-1: Impact assessment matrix for evaluating impact of DG on transmission and distribution network investment and operation including defined drivers for impact 82

Table 3-2: Wind Capacity credit, extract from (UKERC, 2006) 90

Table 3-3: Comparison of transmission capacities associated with key system boundaries derived using the approaches for reliability and the current GBSQSS (Strbac et al., 2007) 95

Table 3-4: Comparison of transmission capacities associated with key system boundaries derived using the approaches for economic efficiency and the current GBSQSS (Strbac et al., 2007) 98

Table 3-5: Total incremental cost of upgrading feeders and substations in rural systems (in £million) for passive (P) and active (A) management (Grenard et al., 2005) 103

Table 3-6: Total reinforcement costs of upgrading switchgear in urban areas (in £million) for passive (P) and active (A) management, with 0% headroom (Grenard et al., 2005) 104

Chapter 4:

Table 4-1: Demonstration of generation and demand TNUoS charging in the North and South of the GB system, and the impact of adding 5MW of additional generation to transmission and distribution (NGET, 2007a) 132

Table 4-2: Illustration of the impact of negative and non-negative tariffs for demand TNUoS charges on cost reflectivity for connection of DG 134

Table 4-3: Summary table of future options for developing transmission investment, access and pricing arrangements against identified requirements for optimal system development. 151

Chapter 5:

Table 5-1 Examples of generation and controllable load parameters for aggregation to characterise a Virtual Power Plant 159

List of Publications

Refereed Journal Papers:

PUDJIANTO, D., **RAMSAY, C.** & STRBAC, G. (2007) Virtual power plant and system integration of distributed energy resources. Renewable Power Generation, IET, 1, 10-16.

PUDJIANTO, D., CASTRO, M., DJAPIC, P., STOJKOVSKA, B., **RAMSAY, C.,** STRBAC, G. & ALLAN, R. (Submitted) Transmission Investment and Pricing in Systems with Significant Penetration of Wind Generation. IEEE Transactions on Power Systems.

PUDJIANTO, D., **RAMSAY, C.** & STRBAC, G. (Submitted) Microgrids and Virtual Power Plants: concepts to support the integration of Distributed Energy Resources. Journal of Power and Energy

Industry Magazine Article:

DJAPIC, P., **RAMSAY, C.**, PUDJIANTO, D., STRBAC, G., MUTALE, J., JENKINS, N. & ALLAN, R. (2007) Taking an Active Approach: Distribution System Transitions and Integration of Distributed Generation in Europe. IEEE Power & Energy Magazine, 10.

Conference Papers:

RAMSAY, C. & LEACH, M. (2005) Can Virtual Utilities Revive the Consolidation Market? BIEE Academic Conference: European Energy - Synergies and Conflicts St. Johns College, Oxford University, British Institute of Energy Economics.

PUDJIANTO, D., CASTRO, M., DJAPIC, P., STOJKOVSKA, B., **RAMSAY, C.,** STRBAC, G. & ALLAN, R. (Accepted) Transmission Investment and Pricing in Systems with Significant Penetration of Wind Generation. CIGRE Session 2008, Paris, France. 24 - 29 August 2008

Book Chapter:

BILTON, M. J., **RAMSAY, C.**, LEACH, M., DEVINE-WRIGHT, H., DEVINE-WRIGHT, P. & KIRSCHEN, D. S. (In press) Electricity Consumption and Demand Side Participation. IN GRUBB, M., JAMASB, T. & POLLITT, M. (Eds.) Delivering a Low Carbon Electricity System: Technologies, Economics and Policy. Cambridge, Cambridge University Press.

Published Reports:

(All available at www.sedg.ac.uk)

STRBAC, G., PUDJIANTO, D., CASTRO, M., DJAPIC, P., STOJKOVSKA, B., **RAMSAY, C.** & ALLAN, R. (2007) Transmission Investment, Access and Pricing in Systems with Wind Generation, January 2007, Centre for Distributed Generation and Sustainable Electrical Energy.

STRBAC, G., **RAMSAY, C.** & PUDJIANTO, D. (2007) Integration of Distributed Generation into the UK Power System: Summary Report. Contribution to the Energy White Paper Consultation 2007, March 2007, Centre for Distributed Generation and Sustainable Electrical Energy.

STRBAC, G., **RAMSAY, C.** & PUDJIANTO, D. (2007) Framework for the development of enduring UK transmission access arrangements, July 2007, Centre for Distributed Generation and Sustainable Electrical Energy.

Abbreviations

BSC	Balancing and Settlement Code
BEGA	Bilateral Embedded Generation Agreement
BELLA	Bilateral Embedded Licence exemptable Large power station Agreement
BETTA	British Electricity Trading and Transmission Arrangements
BSUoS	Balancing Service Use of System
CHP	Combined Heat and Power
CI	Customer Interruptions
CML	Customer Minutes Lost
CUSC	Connection and Use of System Code
CVPP	Commercial Virtual Power Plant
DBERR	Department of Business, Enterprise & Regulatory Reform (Formerly DTI - Department of Trade & Industry)
DG	Distributed Generation
DNO	Distribution Network Operator
DRM	Distribution Reinforcement Model
DSM	Demand Side Management
DSP	Demand Side Participation
EENS	Expected Energy Not Supplied
ER P 2/6	Engineering Recommendation P 2/6
EHV	Extra High Voltage
FPN	Final Physical Notification
FTR	Financial Transmission Right
GBSQSS	Great Britain Security and Quality of Supply Standards
GSP	Grid Supply Point
GW	Giga Watt
HV	High Voltage
ICRP	Investment Cost Related Pricing
ICT	Information Communication Technology
IIS	Investment Incentives Programme
kV	Kilo Volts
kW	Kilo Watt
LMP	Locational Marginal Price
LOLP	Loss of Load Probability
LRMC	Long Run Marginal Cost
LV	Low Voltage

MV	Medium Voltage
MW	Mega Watt
NETA	New Electricity Trading Arrangements (now superseded by BETTA)
NGET	National Grid Electricity Transmission
Ofgem	Office of Gas and Electricity Markets
PPA	Power Purchase Agreement
PV	Photovoltaics
ROC	Renewable Obligation certificate
SRMC	Short Run Marginal Cost
SVA	Supplier Volume Allocation
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System
TSO	Transmission System Operator
TVPP	Technical Virtual Power Plant
UK	United Kingdom
VPP	Virtual Power Plant

Acknowledgements

I'd like to thank both my supervisors, Profs. Goran Strbac and Matthew Leach. Thanks to Matt for welcoming me back to the Centre for Environmental Policy and giving me this opportunity to take my research interests forward. And huge thanks to Goran for investing so much time and effort to give this work (and more importantly this researcher) a truly interdisciplinary and relevant outcome.

Thanks must also go to all those that I have been working with in parallel with my PhD research. In particular to those involved in the Centre for Distributed Generation and Sustainable Electrical Energy, namely Danny Pudjianto and Predrag Djapic, and also to the partners on the FENIX project. The opportunity to work alongside all these people has massively increased the relevance, scope and terms of reference for these studies. As well as making an immeasurable difference to my own understanding of the wider issues brought up through this research.

Thank you also to the rest of the CEP team who shared my PhD experiences with, in particular to Sian Morse-Jones, for providing unending mental and confection based support. Thanks also to Graham Cookson, Ivan Scrase, Matteo Di Castelnuevo, Mark Bilton, Adam Hawkes and Efterpi Lampaditou for all their help and encouragement.

Family and friends from all over the world have also offered great support in many diverse ways, in particular my Mum and Dad, Kathleen and Pippa. Thank you to all of you (and all those not mentioned) for not asking "is it finished yet?" too often and for sticking with me to make the final celebration.

And finally, I am entirely indebted to my husband Chris. Without wavering for a moment, he has supported me in every way possible and has always been on hand with the right amount of stern encouragement, good advice and genuine sympathy. It wouldn't have been done without him.

CHAPTER 1: Introduction

1.1 Background

The role of the network in the modern power system is to transport power securely and efficiently from generators to demand customers; network design, operation and development is dictated by the requirements of these network users, their location, and their patterns of output or consumption. The existence of a network facilitates competition in generation and supply by allowing customers to access the cheapest generation resources regardless of their location in the system; in this context the concept of fair and cost reflective network access is fundamental to the development of efficient markets that create an environment in which all system users follow the same rules and are given an equal ability to compete.

In the United Kingdom (UK), the power networks were shaped by economies of scale in power production which have concentrated generation technologies into a small number of large units generating in locations remote from demand centres. This required the development of an extensive national transmission network to deliver power to regional distribution networks; passive networks that distribute power to local consumers. Typically, the majority of generation capacity was connected at transmission level and, because consumer demand is treated as inflexible and unresponsive, this large scale plant is manipulated to follow load requirements and to provide system balancing and control. The design of the network has been devised in response to these factors, with the market and regulatory arrangements for network access (that guide network operation, investment and pricing) optimised to achieve efficient operation and optimal development of the networks for a system with large-scale conventional generation and passive demand.

However, this conventional picture of the modern power system is on the edge of material change. Current UK energy policy, driven by the growing climate change agenda and the need to reduce carbon dioxide emissions, is guiding the conventional power system towards ambitious goals for penetration of renewable generation. By 2010, 10% of all generation in the

UK should be from renewable sources, and by 2020 this target increases to 20% (DTI, 2007). The exact composition of the future sustainable system up to 2020 and beyond is uncertain. However, it is clear that this future will be materially different from the one we see today; one stimulated by the penetration of generation technologies of vastly differing scales, different operating characteristics and in new locations throughout the network. Under these conditions a new role may be created for demand participation and, crucially, changes may be required in the operation and development of the transmission and distribution networks to respond to the changing needs of these new system participants.

There is a clear need to undertake analysis of the existing arrangements for network access, to establish whether they are capable of facilitating optimal operation and development of the network and providing cost reflective network access for the new system participants. If the current arrangements are no longer an accurate proxy by which the optimal operation and development of the network can be assured then there is the danger that cross-subsidy will emerge between users. This will negatively affect new generation (and emerging roles for demand) by restricting a competitive and fair environment. This, in turn, may slow penetration of these new technologies and prevent achievement of the targets for adoption of low-carbon generation technologies.

This thesis addresses the challenge of providing network access for renewable and distributed generation, and highlights the pivotal role that network access must have to ensure optimal development of the new sustainable system. It undertakes an extensive analysis of the principles that have shaped the regulatory and market frameworks for network access to determine whether they still offer an efficient solution and fair, market based approach for the future sustainable energy system. The research identifies the main gaps in the current provision for access as it applies to non-conventional generation and develops a new framework for the creation of enduring access arrangements suitable for the future low-carbon power system.

The following three sections identify the wider context for this work, before the research aims and methodology are developed in sections 1.5 and 1.6.

1.2 Overview of the current network access arrangements

Optimal network operation and development hinges on balancing the short term costs of operation (constraint costs, losses and unplanned outages) against the long term costs of investment in new capacity. Investment in system reinforcements is signalled when the marginal cost of operation exceeds the marginal cost of investment in new capacity, i.e. the operational

costs such as constraints and losses become more expensive than building new capacity to relieve the local congestion[1]; the result is an optimally constrained network. Network operation costs will be driven by the requirements of the network users, namely generation and demand. When, where and how these network users access the network will impact on the extent of constraint costs and losses.

In practice, comprehensive calculation of the reliability and cost-benefit assessments to determine optimal network development is simplified by network planners. In the UK this is undertaken using deterministic network planning standards. The standards present a proxy of the optimisation process for determining the amount of transmission capacity required to transport power across various system boundaries given a predefined set of generation and demand scenarios (based on the conventional system). Accurate determination of these scenarios is essential not only for optimal network development, but also to ensure that network access arrangements are cost reflective and signal to users the impact their activity has on the network.

The UK network access arrangements are driven by the requirements of a competitive market[2]. The current voluntary trading approach and market for power under British Electricity Trading and Transmission Arrangements (BETTA) sets the high level principles for network access in the UK. The value of power is determined by its location and time of use (Schweppe et al., 1988), however, the wholesale electricity market allows trading of power separate from requirements for network access to deliver the contract. This approach separates energy and access, meaning that power can be bought and sold without consideration of network constraints (i.e. ignoring the location of both generation and demand). The wholesale price paid for electricity represents the value according to time of use (the short run marginal cost of generation), but not location. The locational element to value of electricity is correlated to the cost of resolving constraints on the network and to losses. Under the current arrangements the system operator resolves network constraints close to real time, and this cost (along with the cost of losses) is socialised across all network users proportional to the volumes they have

[1] There are clearly challenges in undertaking this optimisation considering the "lumpiness" of investment in new network capacity which prevents the incremental reinforcement of the network, but the principle of the optimisation still holds.

[2] Commercialisation of the power sector, and the introduction of market based competition began with the introduction of the Electricity Act in 1989 TSO (1989) Electricity Act. The Stationary Office. This set out the plan for unbundling of the vertically integrated and nationalised Central Electricity Generating Board and separation of its assets into a system operation function and privately owned generation operating through a competitive pool market. From this point, successive legislation TSO (1998) Competition Act. The Stationary Office. and regulatory change pursued the goal of increasing competitiveness, and market liberalisation which has resulted in the creation of fully open and competitive markets in generation and supply, and the creation of national and regional regulated monopolies in transmission and distribution. In 2000, the electricity markets were transformed from the compulsory Pool arrangements to a voluntary trading market, based around a wholesale market for electricity in England and Wales TSO (2000) Utilities Act. The Stationary Office, OFGEM (1999) The New Electricity Trading Arrangements. London, Office of Gas and Electricity Markets., Subsequent legislation then created the British Electricity Trading and Transmission Arrangements (BETTA) and united the entire Great Britain (GB) system under a single market TSO (2004) The Energy Act 2004. The Stationary Office.

traded in the wholesale markets. There is no signal regarding the value of electricity derived from its location (the short run cost of network access) sent to users.
In the transmission network, location specific signals on the cost of network access are made to reflect the long-run marginal costs (LRMC) of investment only. The distribution network currently has no universal charging methodology for reflecting the value of network access by location.

To date, this approach of excluding location from the pricing of electricity and using network planning standards as a proxy for comprehensive reliability and cost-benefit assessments to guide network development has supported development of competitive markets. It has broadly promoted cost reflective treatment of network users in systems characterised by conventional technologies. However, the emerging low-carbon system is characterised by the penetration of technologies with significantly different operating characteristics which drive different impact on the network when compared to conventional generation. This presents new drivers for network development and operation, against which the current market structure and access arrangements may no longer be appropriate. In particular because the current approach sends no signals on the short run value of access or the importance of location, and treats users as conventional generating units through inflexible deterministic planning standards.

1.3 Network access to facilitate competition

Without recognition of the changing requirements of both generation and demand in the future sustainable energy system the current access arrangements cannot accurately represent the impact (both value and cost) of non-conventional generation and responsive demand. As well as leading to inefficient system development, this also prohibits competition as it fails to recognise the contribution that non-conventional users could make towards system development. Without appropriate access arrangements non-conventional generation and responsive demand are prevented from providing non-network solutions to traditional network operation problems (such as management of constraints, and mitigation of losses). Central to this appreciation of the value and impact of non-conventional users is recognition of the location and time of use of the system.

Historically, renewable and distributed generators have not been well placed to participate fully in the conventional power markets and compete on the same level as conventional generation (Ofgem, 2001). The legacy of the existing inflexible transmission and passive distribution networks created for the incumbent conventional generators has meant that renewable and distributed generators operating alone rarely become profitable in the current power markets

(Patterson, 2004) and their contribution to network reliability and efficient operation is not well recognised (Lovins et al., 2002). Attempts have been made to address these barriers to effective competition, specifically in the context of facilitating participation in the energy markets (DGCG, 2003, DGCG, 2004, Ofgem, 2003b, Ofgem and Dti, 2004) and in the amendment of the distribution network planning standards to recognise the contribution of distributed generation to security of supply for demand (Allan and Strbac, 2002, Allan et al., 2004). However, even with these improvements to the current regime, most generators (particularly distribution connected units) are still unable to compete with conventional generation on wholesale electricity price (DTI and Ofgem, 2007), and mechanisms are not yet in place to reward (distributed) generators for their contribution to network services.

For new generation to succeed in this environment, a level playing field is required for all system participants, as is the need for recognition of the individual impact of each system participant according to their location and time of use of the network. The challenge for realising the value and calculating the impact of generation connected at different levels in the network is illustrated by the value chain from power generation to consumption, illustrated in Figure 1-1.

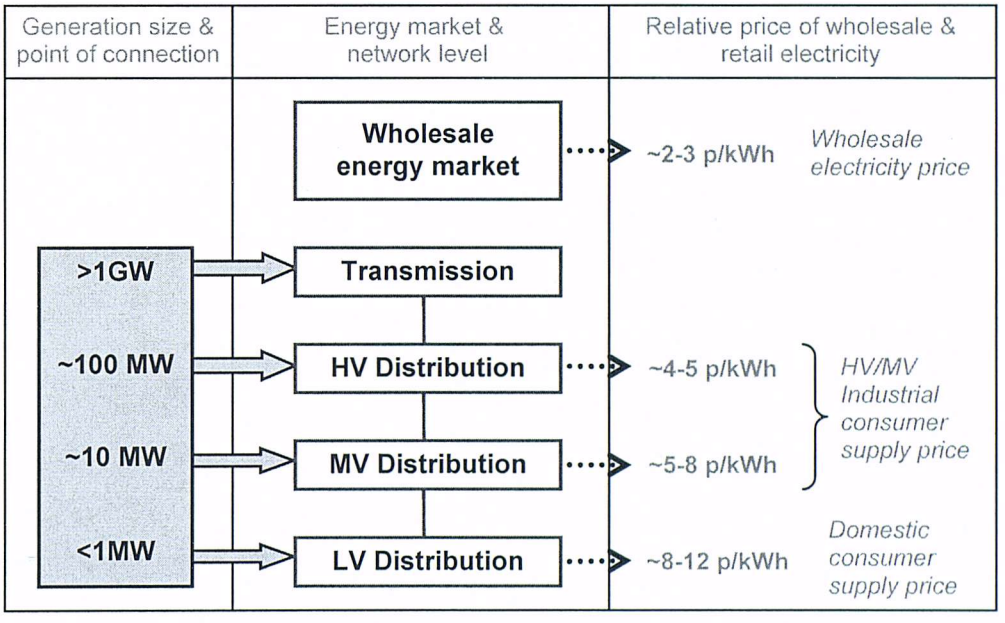


Figure 1-1: Value chain for electricity from central generation to LV distribution

The figure shows the price of electricity produced by centralised generation and sold in the wholesale markets to be around 2-3 p/kWh (the price of wholesale electricity). By the time electricity reaches the end consumer the relative "value" of electricity has increased, and the price, depending on the level in the network, is now 4-10p/kWh (the retail price of electricity).

This increase in value of electricity up to the point of consumption is driven primarily by the added cost of network transmission and distribution services required to deliver power from centralised generators to customers elsewhere in the network.

Distributed generation is located closer to the consumer and has fewer requirements for the transport services afforded by the transmission and distribution networks. In essence, distributed generation is delivering power direct to demand, power that should have an equivalent value of 4-10 p/kWh, i.e. the costs avoided by not using the network. However, this network cost reduction, generated by the favourable location of some generators, is not fully recognised within the present commercial and regulatory framework. As a consequence, non-conventional generation invariably is competing with conventional generation in the wholesale markets at a price (2-3 p/kWh) that may be significantly lower than the true value of electricity delivered from a location close to demand (i.e. 4-10p/kWh). The full value of generation in these terms will obviously be dependent on a number of factors, from time of use and location in the system to density of penetration of similar generation and timing of system peaks with output. In some instances renewable and distributed generators may cause more negative costs than benefit, but the principle of realising the full value of generation still holds.

The same example is also relevant for the treatment of demand. Customers taking energy from the network at the right time and in the right location in the network (i.e. close to generation), have less requirement for network services. Yet for most consumers all power they receive is priced at the fixed retail rate, occasionally reflecting differences in time of use, but never fluctuating in response to location and the distance between generation and the consumer.

Ignoring these particular features (time of use and location) results in sub-optimal network development because the full and true impact of the user on the network is not represented. Ultimately, this prevents new low-carbon generation (and demand) from competing with incumbent generation and traditional network solutions to guide optimal network development, with the result that the system must resort to increasingly expensive and unnecessary network reinforcement, and sub-optimal network support solutions.

1.4 Implications of non cost reflective access arrangements

Figure 1-2 is an illustration of the potential impact of continuing to exclude demand and to connect new renewable energy technologies (RE) and distributed generation (DG) without appropriate access arrangements that represent both user location and time of use (TOU). The first column on the figure illustrates the system we see today; one which has a limited

penetration of low-carbon technologies, and network access governed by an approach that sends no short term signals about the cost of network access. Up to now this has been an appropriate proxy for representing the traditional system based on conventional generation that has a homogenous use of the system based on simultaneous peak output to meet peak demand conditions. So the transmission and distribution network capacity that has evolved will be broadly appropriate for this system, and the arrangements that charge network users will accordingly be broadly cost reflective.

The next two columns present the "Business as Usual" (BAU) future, which maintains this approach to network access and pricing and the "integrated" future, which integrates non-conventional generation (and demand) into network access arrangements.

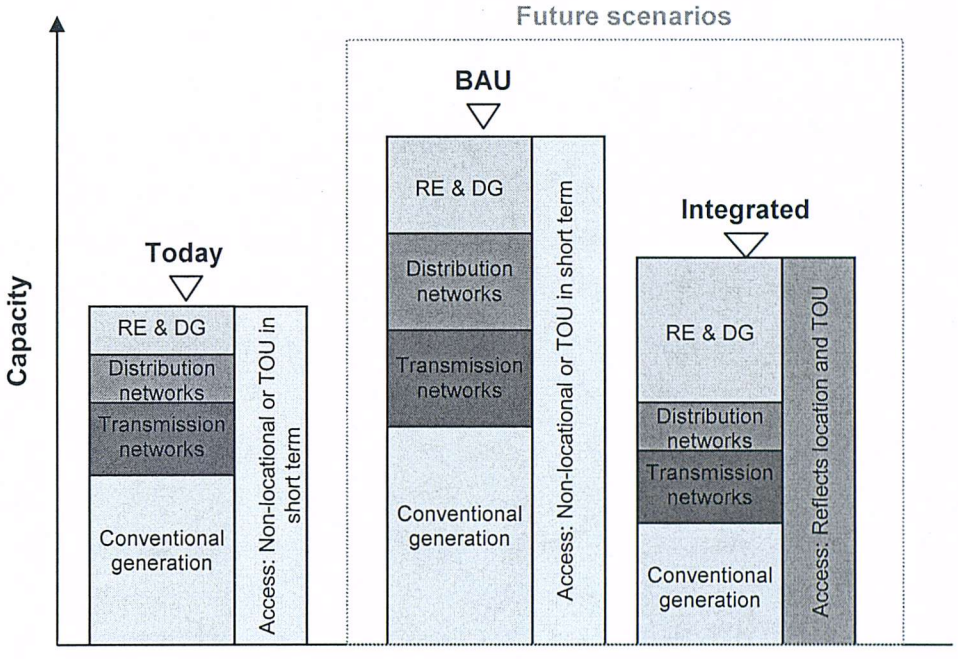


Figure 1-2: Relative levels of system capacity under location/TOU-specific and non-locational/TOU network access arrangements

Under the BAU future, large-scale penetration of distributed generation and transmission connected renewables will disrupt the network. For example, at transmission level, additional wind generation connecting to areas that are already experiencing network congestion (as in Scotland) will contribute to an increased constraint cost and at lower network voltages distributed generation in weak areas of the system may increase voltage levels and cause unwanted voltage rise effects. Under the current arrangements, new transmission connected generation will be treated as conventional generation and impacts such as increases in constraint costs will drive additional transmission capacity according to the existing network planning

standards. For the passive distribution networks, disruptions to the quality of service received by customers are unacceptable, so networks will be reinforced to counteract any negative impacts. The net impact of this, as illustrated in the figure, is a (disproportionate) increase in network capacity in response to connection of renewable and distributed generation. By not integrating these new technologies into the existing access framework the BAU future will continue to respond to network operation and development requirements using only network- and conventional generation based solutions. The absence of fair network access arrangements which facilitates competition between all system users by recognising their individual impact on the network discriminates against new participants. This leads to sub-optimal network development and an unnecessary increase in system costs attributed to non-conventional generation. Ultimately this lack of cost reflectivity may impact the pace of adoption of new generation technologies and limit their penetration.

Alternatively, by developing access arrangements that recognise and integrate the requirements of renewable and distributed generation (and the demand side), this provides the opportunity for the individual impact of all system users to be accounted for. In this instance, the contribution of non-conventional generation (and demand) to network constraints, losses and power flows is noted and charged or rewarded appropriately. For example, some users may drive network reinforcement; some may mitigate or delay it. Providing demand with the opportunity to respond to location based prices opens new opportunities to evaluate demand response as an alternative to network reinforcement. The net effect of redeveloping the access arrangements to reflect the changing system will be an increase in cost reflectivity, and a more optimal (and potentially cheaper) network that is able to evaluate a range of network and non-network options as solutions to traditional network problems.

Historically, the network has had sufficient capacity and resilience to support transactions in the wholesale markets without significant cost accruing for managing constraints. Because this cost was a relatively small percentage of total electricity costs, socialising the charge around all network users, rather than sending location/TOU specific signals to users in the areas directly responsible for the constraint, was also an acceptable charging method. However as the system changes there is the potential for this approach to cause market distortions and sub-optimal operation and development of the entire system, with unnecessarily high costs to consumers.

The materiality of the network access question is coming into focus with the pending connections of large amounts of wind and renewable generation in Scotland and the growing trend for connection of generation at distribution level. These new generation technologies are fundamentally different from conventional generation in the way in which they use the network.

Furthermore, there is dramatic asymmetry between the locations of renewable resources versus demand, with each being prevalent at opposite ends of the UK. Combined with the commitment to market driven system operation and development, network access is likely to play an increasing role in the future sustainable system. This is in part because new non-conventional generation cannot be accurately represented without this appreciation of location and time of use of the system. It is also driven by the fact that a market driven sector relies on accurate and transparent signals that are and will increasingly be masked by the current access arrangements.

1.5 Research question, aims and objectives

This study focuses on a central aim of facilitating optimal network operation and development in a future sustainable power system featuring high penetration of renewable and distributed generation. This should be achieved through development of cost reflective arrangements for network access that maintain a competitive market approach by charging or rewarding all new generation technologies and demand proportionally to their impact on the network. This requires evaluation of the cost reflectivity of the current market and regulatory arrangements for transmission and distribution network access as they are applied to the future system, and the development of new enduring arrangements for network access in the future sustainable system.

Specifically, this can be broken down into four research questions and areas for research, each with individual objectives:

RQ1. What are the main challenges facing development of the market and regulatory arrangements governing network access for the future low-carbon power system?

This requires analysis of the current and future systems and identification of the changes required in the high level principles which drive the market and regulatory arrangements for network access. The specific objectives to respond to this question are to:

- review the physical operation and development of the current system and its regulatory and commercial frameworks as they relate to transmission and distribution network access,
- identify the key characteristics of the future low-carbon system and the drivers for impact of non-conventional generation on the network, and
- identify the challenges and issues for transposing the current regulatory framework onto the future system.

RQ2. What is the impact of non-conventional generation on the transmission and distribution networks?

To determine whether the current access arrangements are effective in the future system requires an understanding of the impact, both positive and negative, that non-conventional generation and responsive demand have on the transmission and distribution networks. With this quantification an assessment can be made of whether the current arrangements deliver outcomes that reflect the true costs imposed by all users on the system. The objectives in this research area are to:

- devise a structured framework to assess the impact and value of non-conventional generation on the transmission and distribution networks in terms of network development (investment) and operation,
- carry out a comprehensive review of existing quantitative studies detailing the value and impact of non-conventional generation in these areas, and
- explore the impact of "enabling technologies" that can mitigate the costs of non-conventional generation on the network, with a focus on demand side participation (and responsive demand) and active distribution network management.

RQ3. Are the current network access arrangements still cost reflective when applied to systems with significant penetration of non-conventional generation?

This section of the research should determine whether the current access arrangements are suitable for application to the future low-carbon system, in the context of maintaining optimal operation and long term development of the network based on competitive market principles and cost reflectivity. It will identify the main inefficiencies in the present network access arrangements that impact on cost reflectivity. The objectives developed to serve this assessment are to:

- identify the characteristics of transmission access required in systems with non-conventional generation,
- conduct a critical analysis of the current arrangements for transmission access in the context of the findings on the impact and economics of non-conventional generation, and
- identify inefficiencies in the current arrangements that are distorting competition and presenting a barrier to optimal network access.

RQ4. What should be the main features of enduring arrangements in access for future low-carbon power systems, and how should the technical architecture of the system support this framework?

This area of analysis builds upon the outcomes from the previous research questions to develop and explore solutions to the key challenges identified in the evaluation of the existing access arrangements for transmission. The objectives of this area are to:

- identify the core principles of new enduring access arrangements for a system with significant penetration of renewables,
- devise regulatory framework options for delivery of network access in future power systems,
- evaluate the options for new enduring transmission arrangements against the core principles and requirements for enduring access arrangements, and
- identify and explore the technical architecture of the Virtual Power Plant concept, to facilitate transmission access for DG and demand.

Synthesizing the findings of the various parts of the work, the study aims to uncover pathways for the evolution of the existing market and regulatory frameworks for network access in order to support the future low-carbon power system; and to do this through maintaining a competitive environment whilst ensuring all generation and demand is provided with equal opportunity to participate and realise the full value of its' contribution.

1.6 Scope and methodology

1.6.1 Scope of the research

The title of this research thesis is "An analysis of the UK regulatory and market frameworks for network access to develop enduring arrangements for a low-carbon power system". The research and analysis that this indicates is bounded in four key ways:

Timescales for enduring transmission arrangements

The timescale for analysis is rooted in the present arrangements, with a view to the short to medium term future – i.e. not beyond 2020. This work is looking at the immediate transitions required in regulatory and market arrangements for network access to accommodate the challenges presented by non-conventional generation already requesting connection to the system and that which is expected in the next 5-10 years.

Scope of market and regulatory analysis

The scope of the market and regulatory analysis undertaken in this thesis takes in network access arrangements from a theoretical level of first-principles. The analysis aims to review the fundamental competitiveness and cost reflectivity of the arrangements and to assess the impact of the high level principles that underpin methods for regulation and market development. More detailed analysis of the implementation of specific regulatory regimes, such as the development or evaluation of incentive mechanisms for network regulation, and detailed market design are outside the scope of this research.

UK focus

The thesis is grounded in research and analysis of the UK system. The UK is leading Europe in promotion of competitive markets for power system development and operation, so a focus on this country captures and builds on this broader framework. There is considerable experience of short term access questions in existing Locational Marginal Pricing (LMP) markets across the world. Lessons learned from these markets will be drawn on for development of the UK arrangements.

Focus on the transmission networks

Through the early parts of the analysis it became clear that the main concern in network access that falls within the timeframe explored in the research is that of addressing the issues surrounding transmission network access (initiated primarily by the large numbers of wind generators requesting connection in Scotland and from offshore generation sites). The initial analysis highlighted the legacy of passive distribution network operation, where network capacity is designed to withstand a range of operational scenarios. This significant provision of capacity means that the present distribution network is sufficiently strong to withstand a considerable amount of DG penetration before it begins to become stressed and place potentially unnecessary costs on system users. As such, although there is ongoing interest in active management and integration of DG to manage the distribution network in real time, these solutions are only economically viable in certain areas where the network is weak and traditional network solutions are not possible (e.g. in built up urban areas where real-estate is prohibitively expensive). Within the time horizon of this research, development of active distribution networks which require markets for ancillary services at distribution level is unlikely to be necessary or cost effective and is thus out of the scope of this work. Although many of the findings are applicable to both distribution and transmission networks, this leaves the main focus of Chapters 4, 5 and 6 on the impact of the current arrangements of transmission access on non-conventional generation, and the development of enduring arrangements to fit the

transmission network. Chapter 6 highlights some of the challenges in the distribution network access area, and this is outlined in the description of further work.

1.6.2 Overarching approach: Whole system analysis

The overarching methodology of this research has been to adopt a whole systems approach to analysis, evaluation and development of frameworks for network access[3]. As illustrated in Figure 1-3 this approach realises the importance linking an understanding of the technical and economic performance of the physical system with an appreciation of the market and regulatory support frameworks to achieve delivery of an optimal network. Regulatory developments and market reform will impact the charging and treatment of users connected to the system, changing the efficiency of network design, and impacting system technical performance.

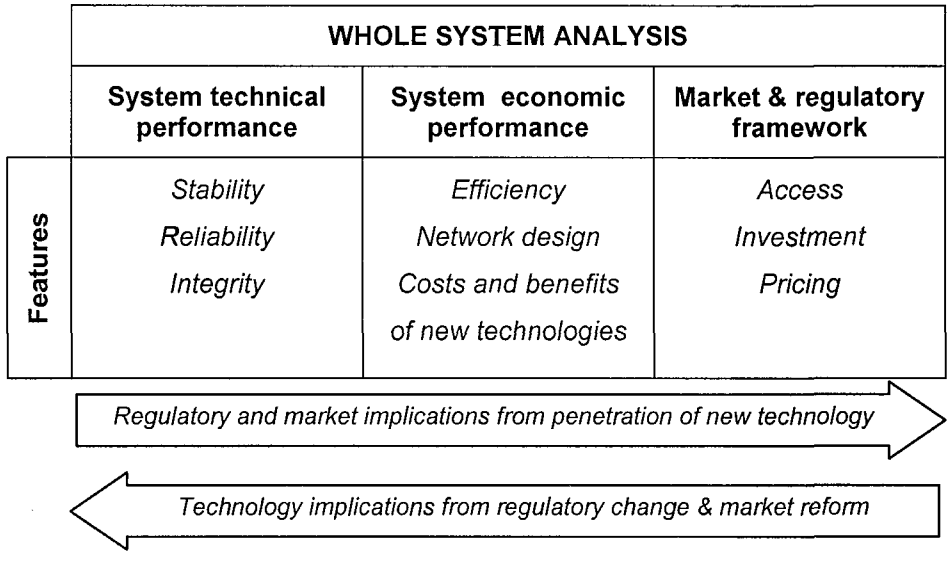


Figure 1-3: Whole system analysis approach

For example, reform of the deep connection charging regime for distributed generation has changed the economics of connection for DG, and should ultimately improve the connection rates of DG to the network, which in turn will affect the network e.g. network reliability. In the other direction, penetration of new generation into the system, e.g. offshore wind, requires new grid codes and definition of technical standards that reflect the economics of offshore wind operation and ultimately this will drive new pricing regimes for charging offshore transmission. Whole system analysis in this way accepts that it is not possible to assess regulatory and market arrangements in isolation from an understanding of the fundamental economics of the system under scrutiny and its technical performance.

[3] Note that the whole system approach is grounded in the power system; although it extends to a consideration of the demand side, it does not include wider interactions with other energy carriers such as gas or heat. Further discussion of this issue and the limitations of this approach are included in Chapter 6.

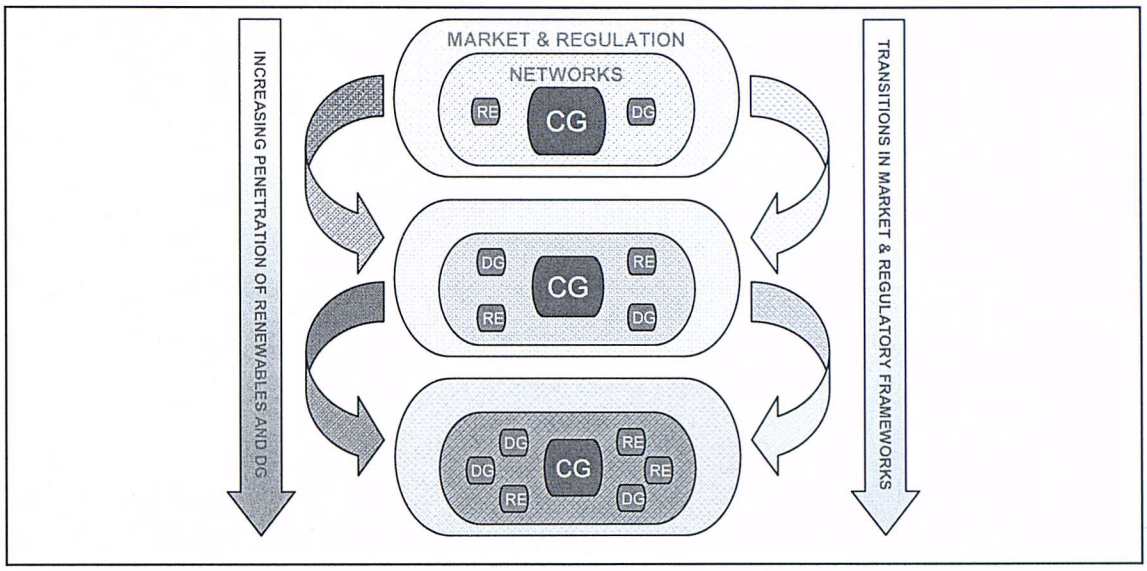


Figure 1-4: Increasing penetration of renewables and DG, and transitions in market and regulatory arrangements driving forward the evolution of the low-carbon system

In the context of this thesis, the analysis focuses on market and regulatory arrangements for network access in systems with significant penetration of renewable and distributed generation. Figure 1-4 provides a diagrammatic representation of the thesis focus. On the left of the diagram is the stimulus for the analysis, that is, the penetration of non-conventional generation into the current system which is causing material changes in the physical system, and altering the impact on the economics of the system.

In response to this, the market and regulatory environment also needs to change (the transitions on the right of the diagram). Market and regulatory arrangements are a proxy to achieve short term efficient operation of the networks and long term least cost development, so in order to maintain a fair and competitive market, they must be cost reflective. To achieve cost reflectivity requires appreciation of the fundamental economics of the system, which is based on an understanding of the physical system infrastructure and technical performance. This has the implication that for the regulatory arrangements to remain a representative proxy of system economics and technical operation they must also evolve to reflect the changing physical system. The whole system analysis method will be used to explore this transition in market and regulatory frameworks for access.

1.6.3 Research methodologies

The specific research methodologies adopted for the research were selected to allow coverage of a broad and interdisciplinary topic. Each chapter has its own methodological structure which centres on qualitative research methods, although in some chapters (3 and 6) there is also

evaluation, analysis and interpretation of existing quantitative studies. The approach for each chapter is outlined in more detail below.

Chapter 2 was constructed using a literature review approach to build the picture of the current status of the power system and to provide detail on the specific access arrangements relevant to transmission and distribution networks. The majority of the texts identified in the literature review are industry documents, as well as reports and consultation papers from government or the sector regulator Ofgem. This was essential to ground the research in the UK network and to ensure elaboration of a comprehensive picture of the existing network access arrangements and the philosophy for development and operation of the networks. Identification of the future low-carbon system was carried out in the same way. Informal input from industry and utility contacts was used to explore and discuss the potential impact of the existing network access arrangements on a future system featuring a high penetration of renewable and distributed generation.

Chapter 3 explores the costs and benefits of non-conventional generation to the networks. The research draws on several quantitative studies carried out by the Centre for Distributed Generation and Sustainable Electrical Energy (CDGSEE). The author, although not directly involved in the quantitative aspect of these studies, has drawn together and interpreted the findings of these reports using a novel impact assessment matrix approach. Key inputs into the subsequent chapters are the synthesis of these findings into a coherent, qualitative review of the impact of non-conventional generation on both transmission and distribution and its implications for network access requirements of generation.

Chapter 4 combines and analyses the output from the previous two chapters, undertaking a critical analysis of the current transmission network access arrangements. The cost reflectivity of the current arrangements when applied to a future system is ascertained through qualitative analysis of the high level characteristics of the future system and assessment of their representation in the existing access arrangements. From this evaluation of the current arrangements, a set of high level principles that define optimal enduring access arrangements was developed. These principles were then used as assessment criteria to determine the appropriateness of new approaches to network access and to evaluate alternative frameworks for new, enduring arrangements.

Chapter 5 proposes and develops a vision for the technical architecture required to support distributed generation and demand access to the transmission networks. Drawing on the challenges for distributed generation access to transmission highlighted in Chapter 4, this

chapter uses a literature review approach to develop the Virtual Power Plant (VPP) concept for transmission network access. This aspect of work was undertaken as part of a European Commission funded project FENIX (Flexible Electricity Networks to Integrate the eXpected Energy evolution). The VPP framework was developed through extensive discussion and input from the FENIX team of European industry (Siemens & AREVA), utility collaborators (EdF, Iberdrola, EdF Energy Networks & National Grid Electricity Transmission) and research groups (IDEA, Labein and ECN). This chapter also presents the findings from the quantitative characterisation and modelling of the VPP concept. This was not work undertaken by the author[4], but illustration of the findings from this modelling is used to illustrate the main functionality of the VPP concept and to highlight the challenges for developing transmission access approaches for distributed generation.

The thesis attempts to cover a broad range of issues around network access including consideration of the market and regulatory frameworks. Inevitably there are limitations to the breadth of this approach and the methodologies adopted. These limitations are discussed further in the final chapter of this thesis.

1.6.4 Contribution and originality of the research

Framing the debate for network access in the UK

The network that was developed to support the traditional power system in the UK was created under different conditions to those that are emerging in the system we see today. The traditional network emerged in an era of centralised control, responding to the homogenous requirements of conventional generation and unresponsive demand. Under nationalised, vertically integrated control, the network installed was designed with the long term development of the system in mind, with the result that it was relatively robust in the short to medium term) resulting in low constraint costs (and a low value to network access). This background dictated the network access arrangements that frame the current system, but the current system is changing – and with it the importance of access is developing.

When considered together these changes are fundamental; the UK network assets are nearing the end of their useful life, the generation system is increasingly different from the conventional mix and opportunities for demand are also changing the network access requirements of this user. Some generation is now connected closer to demand (distributed generation), other technologies are increasingly distant from demand centres (wind generation in Scotland)

[4] The work was carried out by Dr. Danny Pudjianto, lead contributor on the paper PUDJIANTO, D., RAMSAY, C. & STRBAC, G. (2007) Virtual power plant and system integration of distributed energy resources. *Renewable Power Generation, IET,* 1, 10-16. to which the author contributed the work presented in Chapter 5 on the structure and framework of the VPP.

dictated by the availability of renewable resources. Finally, system development is undertaken on the basis of market driven operation and expansion of the network. Without the visibility and insight provided by a vertically integrated utility, increasingly transparent market signals are required to stimulate the optimal operation and development of the network.

The major contribution of this research has been to highlight and frame this network access debate for the UK power system, and to identify the evidence in support of the need for radical change in the current access arrangements. The research explores the old and new systems, and identifies the factors that have driven the access arrangements for the traditional system. It then highlights gaps in their construction that become apparent with a growing materiality of the importance of network access issues. The research draws the boundaries of this debate in the UK, and sets out a new framework for development of enduring access arrangements for the UK transmission system.

Interdisciplinary research and evaluation using a whole system approach

Identification of the core questions to explore network access issues and identification of solutions that assist the optimal development of access arrangements requires appreciation of findings and discussions from an interdisciplinary environment. It involves interpretation of quantitative results from network models and extrapolation of these findings to allow discussion of the impact of the physical system on the regulatory and commercial frameworks. In parallel with this comes the development of alternative regulatory structures and network access arrangements that adhere to the underlying philosophy of an electricity sector driven by market forces, but still reflect the changing physical system and user-network interactions.

In this context another key contribution of this research is in its interdisciplinary exploration of the issues around network access for non-conventional generation. The research attempts to review and interpret quantitative models and build a framework for analysis of these results in a qualitative environment. This has allowed translation of findings across disciplines and has stimulated the convergence of the issues of network access around the central theme of creating new enduring arrangements that support all system users equally using the principles of a competitive market environment.

The whole system approach and findings from this analysis are further critical contributions. This approach presents the fundamental physical principles and economics of the system alongside the regulatory and market structures which support the system. This presents the incumbent system from all angles and has facilitated the identification of significant gaps in the

existing framework, as well as characterisation of the core challenges for integration of renewable and distributed generation and development of a low-carbon power system.

1.7 Structure of the thesis

Each chapter is focused on responding to one of the research questions outlined earlier. When combined, these sections serve to met the thesis aim of facilitating optimal network operation and development in a future sustainable power system featuring high penetration of renewable and distributed generation; to be achieved through development of cost reflective arrangements for network access that maintain a competitive market approach by charging or rewarding all generation technologies and demand proportionally to their impact on the network.

To do this requires an understanding of the existing system and arrangements (Chapter 2) and detail on the impact of the new non-conventional generation on the transmission and distribution systems (Chapter 3). The key outcomes from these chapters can then be synthesised in an analysis of the cost reflectivity of the current arrangements for non-conventional generation (Chapter 4). This highlights the primary areas of inefficiency in the current arrangements and indicates the requirements for a new cost reflective framework for the future system. A framework for the analysis of new enduring arrangements for transmission access is proposed, and several options for network access are reviewed. Finally, an innovative technical architecture to allow transmission network access for distributed generation is proposed and developed (Chapter 5). Chapter 6 presents some discussion on the main points raised and draws together the conclusions from the previous chapters. This chapter also presents a critique of the methods adopted and the research findings and scope, and presents areas for further work.

CHAPTER 2: Network operation and development and challenges for the transition to a future sustainable power system

2.1 Introduction

As outlined in Chapter 1, the primary function of electricity networks is to transport energy securely and efficiently from generation to demand; and the design and operation of the networks will be driven by the characteristics and requirements of both these network users. The location of generation relative to demand, the generation technologies employed in both the transmission and distribution system, together with the pattern of demand, will all influence network operation and development. Changes in the characteristics or location of generation and demand influences the requirement for access to the network, which in turn increases (or decreases) requirement for network capacity. In the UK, with the advent of renewable and distributed generation materialising at every level of the network and the possibilities for demand side participation increasing, the network in place to connect these participants must identify and respond to their new requirements for network access.

This chapter aims to address the core aspects of this challenge, first by outlining the background upon which the current networks and their regulatory and market frameworks have been developed. It then lays out the high level vision of a future power system with a significant penetration of renewables and distributed generation, identifying the different characteristics of generation and demand in this future scenario, and highlighting areas in the current network access arrangements and approach that may no longer be compatible with this new future.

The chapter then details the development of the transmission and distribution infrastructures in place in the UK today. It reviews the technical, commercial and regulatory frameworks that shape the networks and define network access for the conventional system, and highlights how these frameworks have been optimised for a conventional system based on a small number of large-scale generation units. The transmission and distribution networks are addressed in turn;

in each case a review is undertaken of the network access arrangements in place over a short- and long term time horizon. This entails a description of the current design and development philosophy for network investment, the operation philosophy and methods and the network pricing methodologies to charge users (both generation and demand) for their use of the system, and impact on capacity investments. Alongside the description of the current status of the networks, this review of network structure and regulation also identifies the likely challenges to transmission and distribution network access that will result from the penetration of increasing amounts of renewable and distributed generation.

2.2 Overview of the conventional and future power system

2.2.1 Conventional system architecture and characteristics

The conventional power system, as illustrated in Figure 2-1 was designed to support small numbers of large-scale generation technologies; mainly coal, oil, hydro, and nuclear, and more recently gas-based generation. The majority of the generating units in the UK are connected to a very high voltage transmission network operating at 275 and 400 kV, the role of this transmission system being to provide bulk transport of electricity from these large stations to demand centres throughout the network.

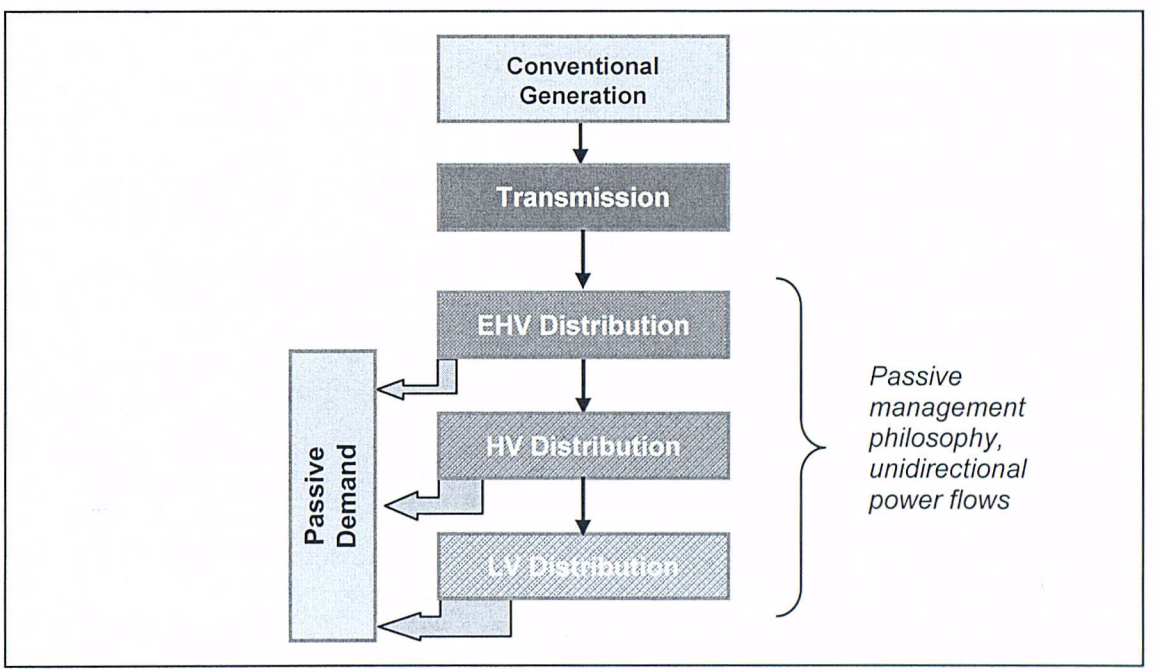


Figure 2-1: Schematic of the conventional power system

At a regional level, electricity is delivered from transmission to the distribution networks and then to end consumers via a number of voltage transformations. End users are considered to be passive consumers of electricity, with little ability to respond to the system and limited elasticity

in demand. Because generation is primarily connected at the transmission level, the flow throughout the system is unidirectional from high to low voltage, passing from transmission to distribution networks and on to consumers.

At transmission level, a distinguishing feature of this system is that it requires tight real-time control to maintain the balance between demand and supply at all times. Because demand is passive and uncontrollable, this control and balancing service must be provided by transmission connected generation running part loaded to provide the flexibility to respond to changes in e.g. the system frequency etc.

Generation

Figure 2-2 shows the current breakdown of installed generation capacity in the UK. Of the total installed capacity (83GW) around 5% (3.6 GW) comes from renewable sources, mostly transmission connected wind generation (1.65 GW) and large scale hydro stations, and approximately 5.5 GW capacity (6.6%) is Combined Heat and Power (CHP) using a variety of fuel sources (DTI, 2006a), two thirds of this capacity is connected to the distribution network, the rest to transmission (DTI, 2006b).

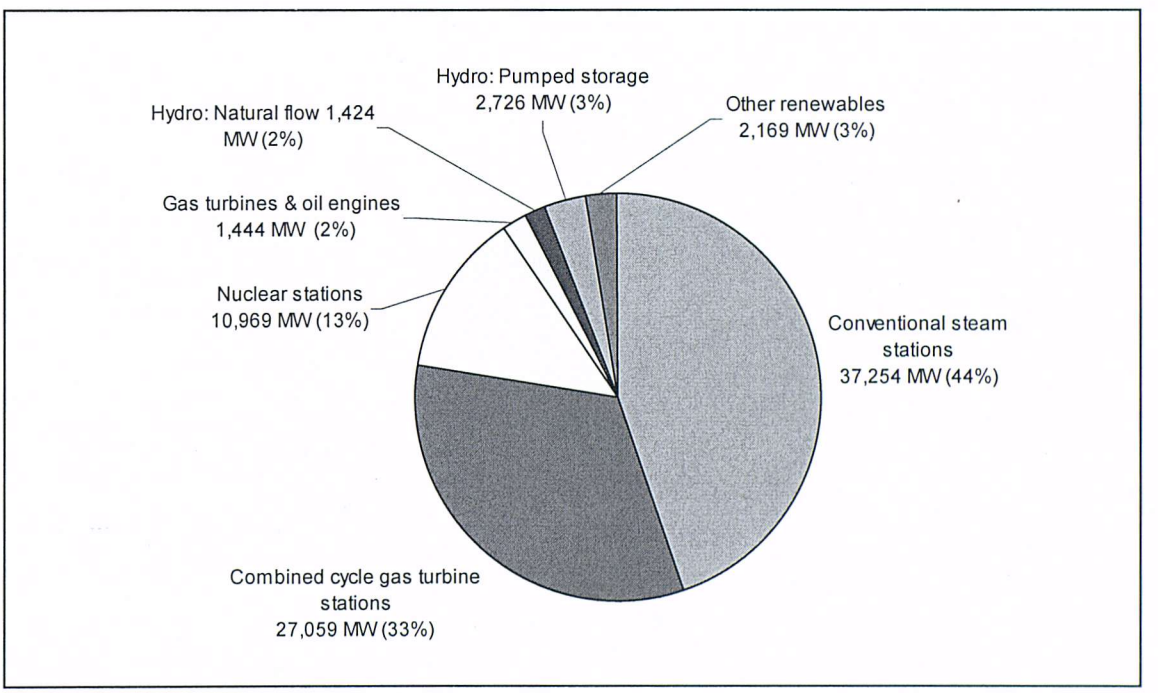


Figure 2-2: Breakdown of generation capacity in the UK by MWe and percentage share (DTI, 2006a)

Accurate calculation of generation capacity connected at distribution level is hard to make, because many of the smaller units are not centrally registered with the transmission system operator. Recent figures (shown in Table 2-1) suggest that around 15% of total capacity is

embedded in the distribution networks with 8.8% of this being renewables or CHP based generation.

Technology	Installed capacity 2006 (MW)	% UK total (84.5 GW*)
CHP	3937	4.6
Hydro	1058	1.2
Onshore wind	944	1.1
Landfill gas, sewage gas	781	0.9
Waste incineration	497	0.6
Offshore wind**	212	0.2
Biomass and energy crops	43	0.05
Tidal stream and wave	7	< 0.01
Photovoltaics	6	< 0.01
Other (mainly gas)***	5205	6.1
Total (Renewables and CHP)	*7485*	*8.8*
Total (All)	**12690**	**15.0**

* Source (NGET, 2005b)
** Most of the proposed offshore wind developments are transmission connected.
*** Medium scale, dedicated electricity generating plant

Table 2-1: Generation capacity installed in the UK distribution networks (DTI, 2006b)

Given that the demand is not controllable to any great extent, and the transmission system operates with a fixed topology (i.e. the transmission network cannot be manipulated to control flows) the sole source of system control lies with transmission connected generators. Instantaneous changes and modulation of generation output are required to meet fluctuations in demand and to maintain system frequency and integrity.

Furthermore, in order to supply demand that varies daily and seasonally, and given that demand is uncontrollable and interruptions very costly, installed generation capacity must be sized to meet maximum (peak) demand[5]. Historically, a generation capacity margin of 20% has been considered sufficient to ensure system reliability. Given the average demand across the year is considerably lower than the peak requirements this means that the average utilisation of generation plant is very low (around 55%), although this figure does vary widely amongst different generators (for example, the very lowest marginal cost generation (e.g. Combined Cycle Gas Turbine) would operate at around 85% load factor, while plant with high fuel costs used for meeting peak demand (e.g. Open Cycle Gas Turbine) will operate only a few hours per year).

[5] In the UK peak demand hours occur in evenings of winter working days usually in December or January.

Costs from generation account for 38% of the consumer's final bill (and costs from suppliers account for a further 30%).

Transmission

The design and structure of the transmission networks has been devised to support large-scale generation technologies. Deterministic planning standards created to guide the development of the network ensure that the transmission system meets requirements on reliability (i.e. that it does not unduly restrict generation from meeting peak demand) and economic efficiency. This involves balancing the operating costs of the network (i.e. cost of congestion, losses and lost load due to outage), against the cost of reinforcing the system. The value of lost load is very high, so typically, the network is installed with a high level of redundancy to ensure that after the outage of a single circuit the remaining lines will not become overloaded and the network will continue to function. This feature means that under peak demand conditions the system is usually loaded below 50%. This level of redundancy has a knock-on effect for losses from transmission; as losses increase (according to a quadratic function) with the loading of the lines. So reduced loading of the lines under normal operating conditions also decreases losses. Losses from transmission are currently around 2% (NGET, 2007a).

Congestion related costs are derived from the physical restrictions of the network preventing the generation schedules that are contracted in the wholesale markets from being delivered. At present (in the UK) the main cause of congestion in the network is the geographic imbalance between generation and demand. An excess of generation relative to demand in Scotland, and a dearth of generation near demand centres in the South-East means that the transmission network is characterised by a North-South net flow, with Scottish generators exporting to England. This means that congestion arising at strategic points in the network must be resolved in real time by constraining generation off in Scotland and dispatching higher cost generation in England. At present the cost of constraints on the system is relatively low, but increased penetration of low marginal cost generation in the North could push these costs up.

Costs from the transmission network account for around 3% of the consumer's final bill.

Distribution

In the distribution networks the approach differs because, historically, there was little or no generation connected at distribution level, so these networks are not controlled in real-time. Any operational problems are resolved at the network design and planning stage such that real time control becomes an investment question on how much reinforcement is required to maintain security and quality of supply under all feasible conditions. Furthermore, because of the lack of

generation in the networks, the standards and guidelines for development and design of the network are exclusively focused on the network requirements of demand. Network capacity is designed on the basis of securing demand, rather than providing generation with a secure route for delivery of power (as is the case in the transmission networks). Distribution Network Operator (DNO) performance is measured by two quality of supply indicators: Customer Minutes Lost (CML) and Customer Interruptions (CI), so provision of service is driven by the incentive to minimise the occurrence of these interruptions. When considering how to mitigate faults and improve these quality of supply indicators, it is noteworthy that the vast majority of interruptions to service come from faults in the lower levels of the distribution network (11kV and 0.4kV) (Ilex and UMIST, 2004). Compared to transmission, losses on the distribution network are relatively high, on average around 7% (Ofgem, 2003a), but increasing well beyond this level in locations where (and at times when) the network is heavily loaded. The low-voltage networks are responsible for the highest percentage of the losses in the distribution network an issue which has implications for the impact of generation and controllable demand in this location which is addressed in the following chapter.

Costs from the distribution network (and metering) account for around 21% of the consumer's final bill[6].

Demand

In the conventional system demand is treated as being passive and largely uncontrollable (apart from a few large demand side customers who offer balancing services to the TSO).

As illustrated in Figure 2-3, daily peak demand usually occurs between 5pm and 6.30pm, with absolute peak demand (~60GW) occurring at this time during winter. Minimum demand occurs during the night, with summer night-time exhibiting the lowest troughs (~21GW). One of the main features of demand in the present system is the diversity that comes from the variety in end uses that characterise the demand sector.

[6] Additional costs derive from the Renewables Obligation (2%), the Energy Efficiency Commitment (1%) and VAT (5%). all cost percentages are sourced from OFGEM (2005c) Household Energy Bills Explained: Factsheet 52. London, Office of Gas and Electricity Markets.

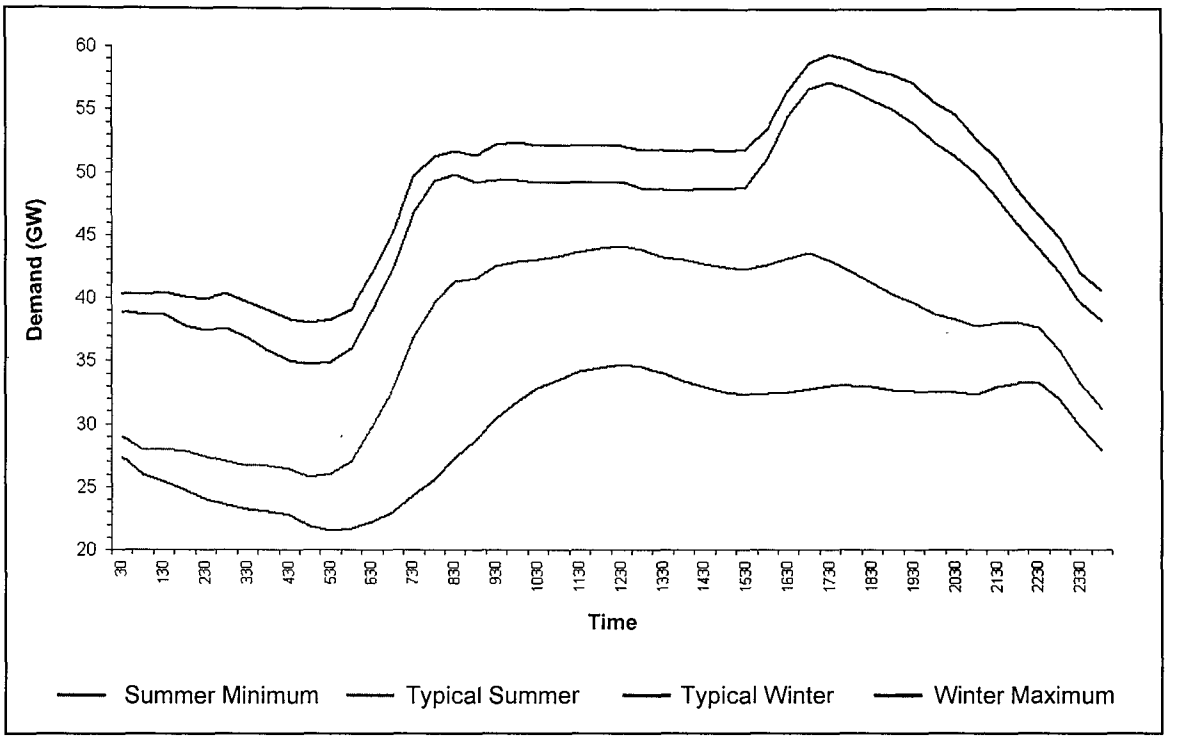


Figure 2-3: Summer and winter daily demand profiles in 2005/06 (NGET, 2007a)

Figure 2-4 illustrates this point; it shows how the demand coincidence factor changes with the number of households. The coincidence factor is the ratio between maximum coincident total demand of a group of households and the sum of maximum demands of individual consumers comprising the group. In other words, the coincidence factor represents the ratio of the capacity of a system required to supply a certain number of households, to the total capacity of the supply system that would be required if each household were self sufficient.

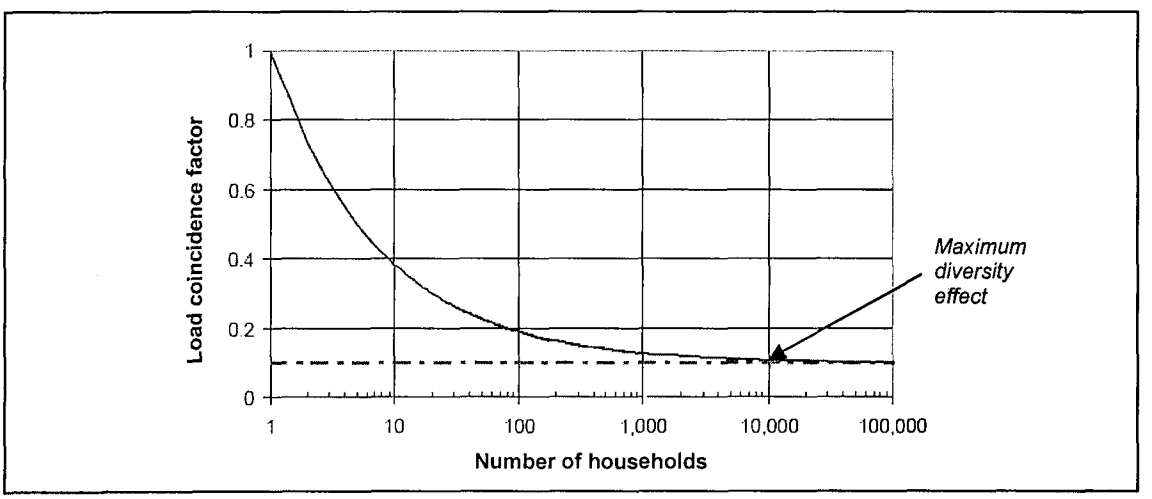


Figure 2-4: Load coincidence factor as a function of number of customer households (Strbac, 2006)

The key to this effect is that diversity in demand means that peak demand for the group is highly unlikely to ever equal the sum total of each individual peak demand. Therefore, the

system capacity requirements (network and generation capacity) can be sized not to the sum of peak demand, but to some reduced level that is proportional to the "diversity effect" of the group. The graph illustrates that the capacity if an electricity system to supply 10,000 homes is almost one tenth of the amount required if sufficient capacity was provided to meet the simultaneous occurrence of their individual peak requirements. Along with the generation mix, this diversity in demand is a defining factor which dictates the design of the network.

The potential for change

However, this conventional system is already in the process of undergoing material change stimulated by increasing penetration of renewable and distributed generation into the traditional generation mix. Outlined in the following sections are the drivers for change that are precipitating the transition and a high level overview of the characteristics of a future power system based on these non-conventional generation technologies.

2.2.2 Drivers for change

A number of diverse factors are driving forward these changes in both the generation mix and the technical, commercial and regulatory environment in which the power system is grounded.

Climate change

Since the Rio Earth Summit of 1992, and the subsequent adoption of the UNFCC (United Nations Framework Convention on Climate Change) and creation of the Kyoto protocol on climate change five years later (UN, 1997), the global environmental challenge of tackling climate change has been focussing UK national policy. The recent publication of the Stern Review, reporting on the economics of climate change (Stern, 2006), further consolidated the call for immediate action, highlighting that taking no action now will increase the costs of both adaptation and mitigation in the future. The development of policies to support a range of low-carbon and high efficiency technologies on an urgent timescale has been highlighted not only through the Stern Review but also through numerous UK government activities. Carbon mitigation strategies, improving energy efficiency and rational use of energy have become primary considerations not only in developing UK energy policy but also as a cross cutting agenda shaping many aspects of policy development (DETR, 2000, DTI, 2003, DTI, 2007).

The power sector, responsible for almost 47 mega tonnes of carbon emissions each year, around one third of total emissions by source (DTI and Ofgem, 2007) is a target for this activity and a sector ear-marked for change. Government policies aim to transform the energy sector with low-carbon technologies and drastically reduce its emissions profile within the next 50 years. Environmental policy making and target setting precipitated by the climate change agenda is

playing a part in shaping the construction of the sector. There are ambitious targets for power generation from renewable sources[7], and increasing pressure on energy suppliers to take an active role in promoting energy efficiency to their customers and a commitment to source a percentage of all power from renewable sources[8].

Aging Infrastructure

The UK electricity generation and network infrastructure underwent considerable development and expansion in the late 1950s and early 1960s. Typically such assets are expected to have around a 40 year lifespan. Now, 50 years on, the assets installed during this period are reaching the end of their useful life and the case for large-scale replacement and reinvestment in new infrastructure is building. Across the UK there is the requirement for capital expenditure on network infrastructure to increase from 63 to 70% of network companies total spend by 2015, leading to an overall capital expenditure requirement of around £2.7bn per annum compared with present level of under £2.2bn (SKM, 2007).

This opportunity for investment and redevelopment of the transmission and distribution networks opens important questions on the asset replacement strategy that should be adopted. The network operation and development philosophies have significant influence on the prevailing generation mix; development of network infrastructure with the new sustainable power sector in mind could play a key role in ensuring the competitiveness and success of renewable and distributed generation. Over the next decade, there is an unprecedented opportunity to develop alternative asset replacement strategies that are in line with the agenda of developing sustainable, secure and efficient electricity systems for the future (IEA, 2007b).

Improving competition and the better regulation agenda

The advent of liberalisation and competitive forces in the power market has also initiated some fundamental changes in the development, operation and regulation of the system. The current market arrangements were developed to support a system based on conventional generation and shaped by the political environment surrounding the changes from nationalised to privatised (and liberalised) industry in the late 1980's and again under the market reforms of 2001[9] (Helm,

[7] By 2010, 10% of all energy generated in the UK must come from renewable sources, and 10GW of new CHP must be installed in the distribution networks (DETR 2000), with a commitment for an additional 10% (20% in total) by 2020, as part of a new European Union backed commitment to low carbon generation CEC (2007) An Energy Policy for Europe. Commission of the European Communities.

[8] The Energy Efficiency Commitment (EEC) commits all UK energy suppliers to improving energy efficiency in the domestic sector, through saving a pre-negotiated amount of Carbon over a set time period. The Renewables Obligation ensures that all energy suppliers purchase a pre-negotiated amount of their power from renewable sources (see www.ofgem.gov.uk).

[9] Transition from the "Pool" arrangements to the New Electricity Trading Arrangements (NETA), a bilateral trading and wholesale market.

2003), and 2005[10]. Although introduction of competitive markets into the electricity sector was completed over 15 years ago, these market and regulatory arrangements are still developing, and the debate continues as to what framework will deliver a secure, cost effective and sustainable system.

There is a growing government commitment towards a better regulation agenda, promoting reform to improve market efficiency and transparency of operation. Reviews of recent developments in transmission and distribution network regulation reveal that the UK is at the forefront in Europe with regard to the development of a competitive market in electricity and towards integration of the sustainable low-carbon agenda into market rules and regulation (Djapic et al., 2007, Gomez et al., 2007).

Security of energy resources and reliability of supply

Issues of energy security have also come to the forefront. Security of energy supply has been raised at International and European levels (CEC, 2001, CEC, 2007, IEA, 2002, IEA, 2007a) and is influencing UK decision making on a number of planes. From the basic considerations of "keeping the lights on" and providing homes with uninterrupted power supplies under all conditions, to wider concerns of ensuring a diverse energy supply, maintaining secure import routes for the primary fuels and hedging against the risk of unpredictable or rising fuel costs, UK energy policy is adapting to attempt to meet all these challenges (DTI, 2006c, DTI, 2007). The influence of these factors is seeding a change in emphasis in government and private investment in the power sector, encouraging a broader base of generation technologies, and beginning to favour those technologies that diversify the current portfolio of generators away from a reliance on fossil fuels and unpredictable prices (Awerbuch and Sauter, 2004, Patterson, 2003).

2.2.3 Future system architecture and driving factors to challenge the current system

The architecture of a future power system based on significant penetration of renewables and distributed generation will be materially different from the conventional system that we see today. Figure 2-5 illustrates this with a high-level schematic diagram that identifies the key differences by adapting the illustration of the conventional system shown in Figure 2-1.

Firstly, generation of varying sizes and technologies will be connecting to all levels of the network and there will be a diminished role for large-scale conventional generation. From

[10] Transition from NETA to the British Electricity Trading and Transmission Arrangements (BETTA). BETTA was an expansion of NETA to include Scotland into the England and Wales market, making one single transmission system overseen by a single system operator.

domestic scale μCHP of a few kW generating capacity at the low voltage distribution network, up to large transmission connected wind farms of over 1GW, there will be generating units connected at any point in the network. Penetration of CHP will be driven by the benefits of improved efficiency from co-generation[11] (HoL, 2005). Decentralisation of these generation units into distribution networks is necessary to reduce heat losses, and help size units according to heat demand (Patterson, 1999).

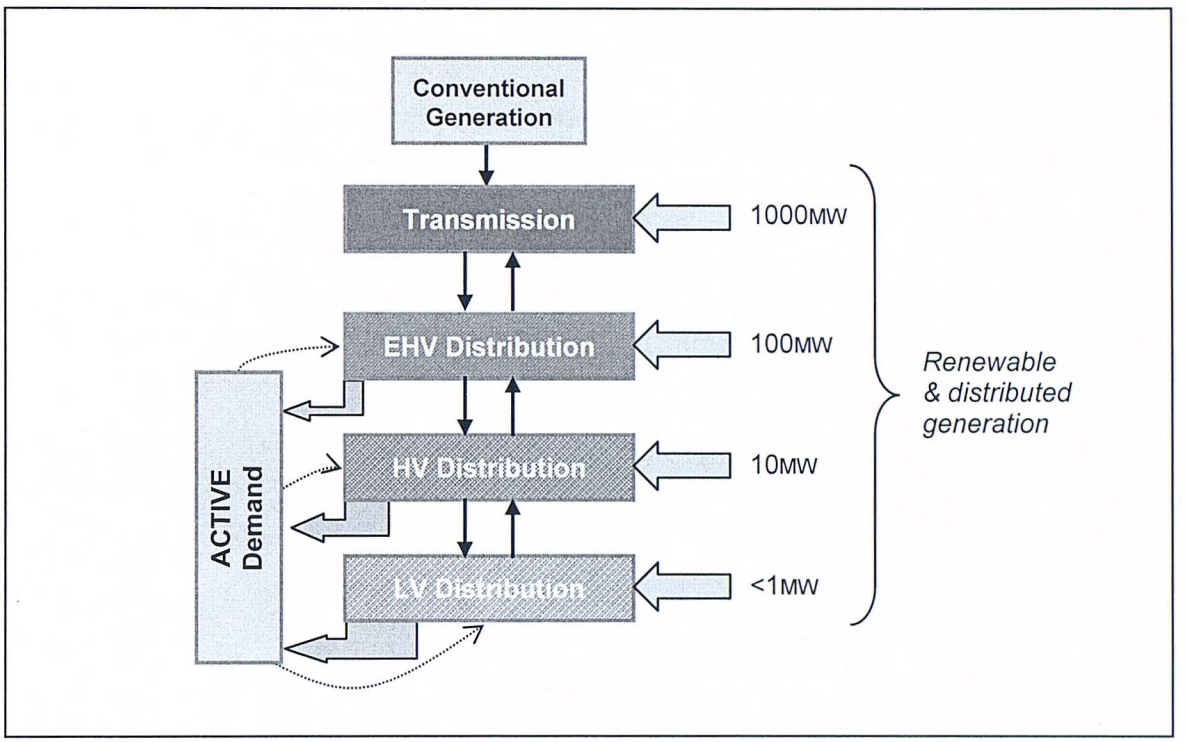


Figure 2-5: Schematic of the future sustainable power system based on transmission connected renewables and distributed generation

The spread of generation connections across the network has implications for power flows. Previously, where the majority generating capacity derived from large scale transmission connected generation, there were unidirectional power flows through transmission to distribution networks, and then on to end consumers via a series of voltage transformations. With the penetration of generation throughout the network these power flows will change. As illustrated in the figure, between voltage levels in the distribution network there may be reverse flows caused by generation connected to the distribution network producing more output than can be consumed by local demand. In some instances this may result in reverse flows at the transmission-distribution boundary and export from the distribution network back on to the transmission grid.

[11] The average conversion efficiency for UK generation mix is around 0.38, compared to 0.8 for the more efficient co-generation schemes found in Denmark and Sweden HOL (Ed.) (2005) *2nd Report of session 2005/2006 - Energy Efficiency Volume II, Evidence,* London, HMSO.

As well as changing the direction of the flows, increased penetration of generation into the distribution networks may also change the magnitude of the flows on the network. Sited closer to demand, distributed generation will reduce the distribution network import requirements, reducing the requirement for transmission capacity. However, this will not mitigate the requirement for transmission entirely; much of the generation that characterises a future low-carbon system is constrained in its choice of location on the network by availability of primary resources. For example wind generation, the best wind resource in the UK is in Scotland and offshore; however the majority of the demand in the UK is in central and south-east England. For this type of location constrained generation that cannot be sited close to demand, transmission will still play a key role in long-distance bulk transportation of power.

In the conventional system, the availability of flexible, controllable generation to maintain the system frequency and integrity and ensure that supply meets demand at all times is crucial. Within the new system, the maintenance of system integrity is equally important. However, with a reduced presence of conventional large scale generation, this system control must come from the new non-conventional generation units and from responsive demand. Without integration of these new generating technologies (and responsive demand) into the system operation activities, a larger proportion of conventional generation must be retained as system reserve and investment must be made in increasingly uneconomic network solutions to mitigate the impact of maintaining a large percentage of uncontrollable generation in the system. Given the average demand across the year, the average utilisation of the generation capacity in the conventional system is below 55%[12]. This relatively low average plant utilisation opens a significant scope for involvement of an active demand side as shifting load from peak to off-peak periods would reduce the need for generation capacity and increase the utilisation of generating plant and hence increase the efficiency of generation investment.

Finally, the operating philosophy of the distribution networks is likely to change. With bi-directional power flows and an influx of generation into the network it will be increasingly difficult for the distribution network operator to maintain a passive operation approach without investing heavily in network reinforcement. Active management of the network would allow integration of local generation and utilisation of this resource as part of daily network operation. This approach would go some way to recognising the value of generation by location in the network, by identifying the benefits that some units can bring through their proximity to load and the correlation of their output to system peaks (Lovins et al., 2002).

[12] There is a significant spread in utilisation among different generators. The lowest marginal cost plant would operate at abut 85% load factor (e.g. CCGT), while plant with high fuel cost (e.g. old OCGT) would operate only a few hours per year.

The impact of the new generation technologies on the transmission and distribution networks is driven (or mitigated) by a series of factors that will affect the extent of the changes described above. These drivers can be separated into locational and operational characteristics, and are broadly defined as follows:

Locational characteristic drivers:

Geographic location:

The geographic location of generation in the system relative to demand will drive and determine key impacts on the network. In the UK example demand centres are in the South, and there is a general north-south power flow down the country. Generation siting in the north will contribute to this flow, generation in the south will alleviate it.

Diversity of local network users:

Relevant at transmission and distribution level, the nature of other users of the network in a local area will play some part in dictating the overall impact on the network. Where there is considerable diversity in use of the network (e.g. two generation types with output at uncorrelated times of the day) the combined impact of a diverse set of users on the network is less than the sum of its component parts.

Density of local installations:

Related to the diversity driver, the density of installations will also drive impact. Up to a certain penetration there may be no impact at all, then beyond this a positive effect, and beyond this again the costs may outweigh the benefit. Density and homogeneity of installations will play a role in the impact of non-conventional generation.

Operational characteristic drivers:

Pattern and time of output:

Typically, conventional generation is load following and its use of the network is according to patterns of demand. In the future system, much of the new transmission connected (e.g. wind) will be driven by other factors such as weather conditions, that are not well correlated to demand conditions. Factors such as intermittency and variability and the extent to which they influence output will also be important.

Capacity credit:

Capacity credit is a measure of energy to capacity ratio; it indicates the amount of existing plant capacity that can be displaced on addition of new generation to the system whilst still maintaining a given level of system reliability. This driver is important in guiding transmission

network reinforcements in systems designed for reliability and can have an impact at distribution level where generation with high capacity credit is able to displace network capacity. Flexibility and controllability of generation is the key to maintaining the system frequency and integrity, the contribution that generation technologies can make to this will contribute to their capacity credit.

(Distribution) Network management philosophy:

The approach taken (at distribution level) to network management can have a mitigating effect on the impact of distributed generation on the network. Traditionally the network is passively managed with all network issues resolved at the planning stage. Under an active management regime problems can be managed and mitigated in the operational timescale, reducing the need for network reinforcement.

Size of generation plant:

Many DG and renewable generation technologies are too small to have a significant impact on some areas of the network when considered alone. However, as part of an aggregated group with a cumulative profile they can have a more significant effect.

2.2.4 Materiality of the changes to the UK generation mix and demand

In the short to medium term the biggest change in the UK system will come from connection of on and offshore wind connection. At present, there is 16GW of wind capacity with outstanding applications for connection to the GB transmission system in Scotland[13]. Even if only a proportion of these developments goes ahead, against the current installed capacity of onshore wind of 1.65 GW, onshore wind generation is likely to make a considerable and material impact on the transmission system. Further impact is also felt because these generators are all connecting in the Northern reaches of the transmission system, where the network is already congested, and where generation dominates demand. Offshore wind is also set to play a significant role in the UK power system. With 214 MW already operational, there is a further 1GW of capacity awaiting completion and connection under the first round of offshore generation licences, and 7.2 GW from the second round (BWEA, 2007).

[13] These applications came online in 2005 as a result of the switch from NETA to BETTA and the unification of the Scottish transmission network with the English and Welsh system to make a single GB network. This queue was created because automatic rights to access were given to all applications outstanding at the time of the introduction of BETTA, an amnesty which caused a flurry of applications to connect before BETTA came into effect. It has been argued that this prompted many developers to submit more speculative proposals for investments, such that this 16GW of wind applications may represent a considerable number of projects that might not go ahead. The System Operator is concerned that the GB queue is maintained because developers are keen to retain their place in the queue in case this position becomes valuable and can be traded at some point in the future. NGET (2007b) Open Letter on the Management of the GB Queue. National Grid Electricity Transmission. Projections from the System Operator for generation capacity growth in the transmission system up to 2010 indicate a further 10GW of capacity coming online, with just over 3GW of this in Scotland OFGEM (2006b) Enduring Transmission Arrangements for Distributed Generation: Further Thoughts Document. *Further Thoughts Document.* London, Office of Gas & Electricity Markets.

Demand Zone	Increase up to 2009/10 (MW)	
	Generation	*Demand*
North Scotland	622	71
South Scotland	717	57
Northern*	290	117
North West	916	226
Yorkshire*	752	96
North Wales & Mersey	149	24
East Midlands	702	228
Midlands*	138	261
Eastern*	1134	575
South Wales	771	227
South East	453	233
London	76	458
Southern England	199	407
South West	183	196
TOTAL	**7103**	**3151**

Table 2-2: Projected increase in generation and demand in the 14 demand zones across the UK (Ofgem, 2006b)

In the distribution networks, forecasting penetration of generation is subject to considerable uncertainty. Recently, projections for the likely future growth in both generation and demand were requested (by Ofgem) from UK DNOs for the 14 Demand Zones across the system (Ofgem, 2006b). The resulting response is summarised in Table 2-2 which indicates the total expected increase in generation and demand up to 2010. Although the exact figures are subject to change, of note is the overall trend of the increase in distribution connected generation outstripping demand, and of generation in the Scottish demand zones exceeding demand growth by a considerable margin.

Finally, developments in the roll-out of domestic smart metering technologies are also set to change the responsiveness and involvement potential for the demand side. A European directive on the End Use Energy Efficiency and Energy Services came into force in the EU in April 2006 (CEC, 2006a) The directive provides for Member States to take forward a range of energy efficiency measures by May 2008; this range of measures (on some interpretations) includes action to deliver time-of-use metering for the domestic sector where it is deemed to be technically possible and financially reasonable and proportionate. A recent Datamonitor report estimated that 41% of European homes will be equipped with an electronic energy meter by 2012 (Datamonitor, 2007). In the UK, trials of smart metering technology have been announced (Ofgem, 2006a), with large scale roll-out of new meters expected in the medium term future. The emphasis of this initiative has been on the benefits for energy efficiency in improved

information to consumers, however there is also the potential for smart meters to provide new opportunities for demand participation in energy and other markets through demand response activities and smart appliances (Bilton et al., Forthcoming).

2.3 Network access: Alternatives for investment and pricing

With this description of the conventional and future power system and the overview of the potential changes in the UK system in the near term as a context, the following sections go into detail on network access arrangements in the current system. To provide an overview to this process the following section discusses the background to network access and charging arrangements. This details the alternative approaches to cost reflective charging for access based on long and short run costs, and highlights the importance of a locational and time of use element to charges.

Following this, network access in transmission and distribution is reviewed by looking into the technical, market and regulatory arrangements for access in the system operation (short term) and investment (long term) horizons. Overlaid on this detailed identification of the historical drivers and philosophy behind the current system are the challenges of the future system and the drivers for change in system operation and development. These areas explore how non-conventional generation will reshape the system, and how the regulatory framework will respond to maintain economically efficient and optimal network operation and development.

2.3.1 Overview of cost reflective charging for network access

Electricity is a commodity with a value that varies with location (of generation and consumption) and time of use/generation. Value is attributed to electricity on generation, transmission (transport over national grid infrastructure), distribution (delivery to local demand centres) and supply (metering and service provision). Costs are incurred at each of these points e.g. through losses, network congestion, network operation/maintenance and metering.

In the context of electrical power systems and charging for network access, cost reflectivity of charges is required to send accurate price signals to individual users of the network with respect to the costs they impose on network operation and/or development. This will ensure that in the short term, the system is efficiently operated without cross-subsidy between users and that, in the long term, it follows the path of least cost development (efficient investment).

For network operation and expansion, this requires some form of coordination between generation and network development as the optimisation of the network in isolation from generation would almost certainly not meet the above objective. Historically, vertical

integration of conventional utilities seemed necessary for a sufficient level of coordination to be achieved. In the competitive environment, as exists in the UK, the necessary coordination of investing in generation and network assets is to be achieved through efficient network pricing mechanisms. These price signals directed at users of the network should be developed to influence their future decisions with regard to (a) location in the network (b) patterns of network use and (c) the need for (and location of) new network investments, i.e. encourage efficient network investment and discourage overinvestment.

2.3.2 *Long-run versus short-run marginal pricing of network access*

One of the consequences of the deregulation process in the UK has been the separation of generation from transmission. This separation is indeed frequently considered indispensable to achieve open and non-discriminatory access to the energy market. In this environment, pricing of transmission becomes the key to achieving both efficient operation and least-cost system development of the entire system. Coordination of investments in generation and transmission, which are now operated as separate entities, is to be achieved through efficient network pricing mechanisms.

This development has opened the debate into the need to restructure the framework for investments in the transmission network. Long term investment can be achieved through two complementary directions: (i) merchant transmission investments and (ii) transmission investments based on regulatory incentives.

The first approach starts from the view that market forces are the keys to investment and expansion in transmission. Location specific, short-run marginal cost based pricing is now a well-established method for allocating scarce network resources (Schweppe et al., 1988, Hogan, 1999). Locational marginal prices (LMP) computed from a bid-based security constrained dispatch and combined with financial transmission rights (FTR) have been successfully implemented in several major electricity markets (Bushnell and Oren, 1997, Baughman, 1997, Ilic et al., 1997, Read, 1997). Locational marginal prices, coupled with FTRs, provide a conceptual framework for both pricing and transmission investments (Hogan, 1992). Funds created by the purchase of FTRs should support investment for transmission expansion. In this case, investment decisions should be effectively made by the users of the network, rather than centrally by transmission network operators, based on their forecasts of future needs.

The second approach starts from the premise that transmission network is inherently a monopoly and hence needs to be regulated. In this approach, the transmission investment is planned centrally by the transmission network operator for approval by the regulator. All

generators and loads are usually given (almost) firm access rights, and they are compensated if the network is unable to accommodate their power outputs. The key responsibility of the regulatory agencies that determine the income of transmission developers is then to organise incentives that encourage an efficient transmission expansion. This approach has been adopted by the majority of European countries including the UK, and the corresponding transmission pricing arrangements are based on transmission investment costs, rather than generation costs as in the LMP model. To signal efficient behaviour regarding location and timing of output, efficient network prices for long term access should be based on future network expansion costs. Establishing these costs is a fundamental part of network planning, and draws an intrinsic link between the efficiency of the planning process and the subsequent development of a cost reflective pricing regime (Strbac et al., 2005). Rather than simply facilitating revenue recovery for the system operator, network prices should provoke user responses focussed on managing risk and uncertainty to optimise a position in the future (Turvey, 2005). The risk for system users can be minimised, and decisions made more efficient if network planning is carried out under the principles of non-discriminatory access and in recognition of the potential value and impact that all users have on the network.

In theory, both of the discussed approaches for long and short term pricing of network access should deliver the same transmission network investment if perfect knowledge of the future were available. This convergence of long and short term prices is a consequence of the theoretical optimum in which the long run marginal cost equals short run marginal cost (Boiteux, 1960).

2.4 Transmission network access

The following section explores fundamental principles and regulatory frameworks behind the operation and development of the transmission system and looks at how they have shaped the existing infrastructure and define future network investment and real-time operation. The analysis then discusses the impact of penetration of renewables and DG into this framework and explores how various drivers (geographic location, diversity, pattern of generation etc.) are likely to influence the evolution of the regulatory framework that support the transmission networks.

2.4.1 Transmission network long term access: design and investment

The development of planning standards for transmission investment

Networks exist to connect demand and generation, so network requirements are driven by the location and characteristics of demand and generation. For centralised networks with large scale

generation in remote locations from demand centres this necessitates a significant transmission system for bulk transport of power from large power stations (often in remote locations) to demand centres. In the UK, the current transmission system was built to facilitate the bulk transfer of power from large coal fired power stations in the North of England, to demand centres in the Midlands and South East of the country. The benefits of interconnection also meant that regional electricity companies were able to take advantage of generating surplus in neighbouring areas that provided an improvement in reliability for the individual areas in the interconnected network. In general, the benefits of an interconnected power system that are derived from an extensive transmission network are:

- Efficient bulk transport of electricity (minimisation of losses): an interconnected transmission system provides the means for efficient bulk transfer of power from generation to demand centres
- Facilitation of the competitive market between generation and supply: the interconnected transmission system, by linking together all participants across the transmission system, makes it possible to select the cheapest generation available
- Reliability & security of supply: transmission circuits tend to be far more reliable than individual generating units, and enhanced security of supply is achieved because the interconnected transmission system enables exploitation of the diversity between individual generation sources.
- Efficient, cost effective utilisation of generation capacity: realisation of diversity in the interconnected transmission system enables surplus generation capacity in one area to be used to cover shortfalls elsewhere on the system, resulting in lower installed capacity requirements to provide generation security for the whole system
- Efficient provision of system services: without transmission interconnection, each separate system would need to carry its own frequency response to meet demand variations; with interconnection the net response requirement only needs to match the highest of the individual system requirements to cover for the largest potential loss of power (generation) rather than the sum of them all.

For the transmission system operator this means optimising transmission design, reinforcement and operation, to find an optimal combination of long term infrastructure investments balanced against real-time system operation that delivers these benefits at least cost. Planning this optimal system requires the consideration of a complex array of factors, including forecasts of growth in demand and generation with their temporal and spatial distributions, together with the technical and cost characteristics of generation. These forecasts must then be combined into a forecast of future energy market conditions in order to answer the key questions as to where, when and

what transmission reinforcement is justified. Network investment driven by economic efficiency is focused on allowing efficient use of generation sources across the system, and planning transmission capacity that doesn't distort the market unnecessarily or inefficiently. In this context, evaluating possible schemes involves comprehensive technical, economic and reliability assessments that balance transmission investment costs against generation operating costs (cost of network constraints[14] and losses) and the cost of un-served demand due to lack of capacity and availability of transmission. Optimal transmission capacity is obtained by minimising these operating costs and transmission investment as illustrated in Figure 2-6.

The figure illustrates that optimal transmission capacity is found by balancing the transmission investment cost against the benefit derived from this investment by way of reduction in out of merit generation. Under the current Great Britain Security and Quality of Supply Standards (GBSQSS) the requirement for high standards of system reliability usually ensures that the system specification already exceeds the capacity that would be proposed under planning proposals for economic efficiency alone. However, the consideration of DG in system planning may change this balance. As demonstrated in the previous section, many DG technologies make a limited contribution to reliability of the network due to low capacity credits. As such, planning the network on the basis of generation contribution to reliability alone may no longer be optimal.

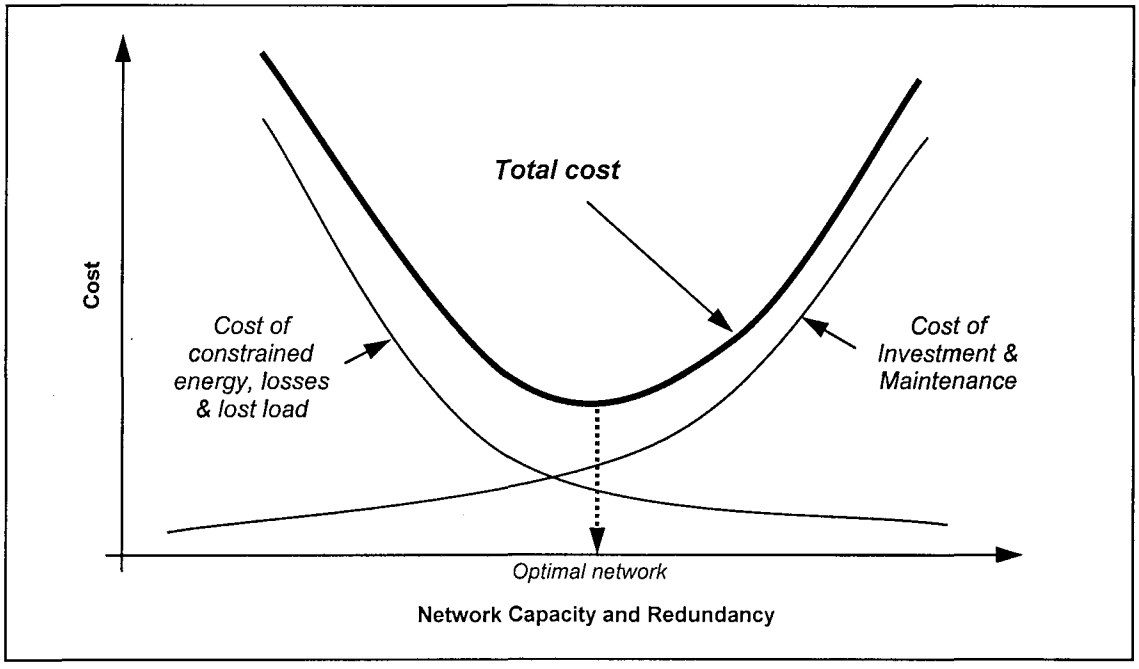


Figure 2-6: Optimal balance between transmission investment and operating cost

[14] The cost of constraints is in essence the cost associated with dispatching more expensive generation instead of cheaper generation due to network capacity constraints. This cost is also known as out of merit order generation cost.

In practice, the System Operator uses simpler deterministic planning guides (also called network planning standards) that present a proxy of the comprehensive reliability and cost-benefit assessments for determining the amount of transmission capacity required to transport power across various system boundaries given a predefined set of generation and demand scenarios.

The GBSQSS drive the design of the GB Transmission Network and were developed as a proxy for investment in systems with conventional generation (NGET, 2004). The focus of the GBSQSS is on the development of networks that guarantee high levels of reliability. Economic efficiency of network development is also important, but the priority of reliability generally ensures that network reinforcements that meet reliability standards will exceed the capacity required if only economic efficiency is considered. The key underlying philosophy of the GBSQSS standard is that generation in one area of the interconnected transmission system should not be unduly restricted from contributing to securing supply for loads in a remote area, via the interconnected system. If necessary, this requirement drives reinforcement of the network to ensure that this criterion can be met. To do this, network planners traditionally would consider conditions of peak demand to determine the need for transmission network capacity across the major transmission boundaries based on these reliability requirements.

For a system with conventional generation, network design driven by peak conditions is also adequate for a wide range of off-peak conditions, including planned outages of both generation and transmission facilities. In designing networks to meet this reliability criterion many other conditions concerned in network planning will also implicitly be met, for example losses; a network designed for reliability has a high level of redundancy which keeps loading of the network low, thus minimising losses as a side-effect of the design.

The existing methodology was developed for conventional generation and considers contributions to the system at times of peak loading to be the primary driver for reinforcement of the network. The current standard presumes that because conventional generation is load-following, that plant will be operating at close to maximum output at times of peak demand (to take advantage of peak prices). A scaling factor is applied to modify output according to expected load factors e.g. conventional generation has a scaling factor of 0.83, wind generation a factor of 0.6 and this is used to calculate the capacity requirements for a system with a given installed generation capacity and demand requirements. The scaling factor for low-load factor generation such as wind was recently introduced into the GBSQSS, however, there is ongoing discussion on the appropriate scaling factor to be used for wind, with alternative studies suggesting a factor of between 20-40% may be more appropriate (SKM, 2004, Strbac et al., 2007).

Network investment for reliability

The relationship which defines transmission network capacity required to achieve system reliability is not always clear, and in many systems techniques to determine adequate transmission capacity to ensure system reliability has been developed through the codification of long-standing heuristic rules (as described in the GBSQSS). To allow analysis of the impact of non-conventional generation on designing transmission networks for reliability, this section explores the link between overall system reliability metrics and the specific contribution of the (constrained) transmission network on system reliability[15].

In many countries, overall system reliability is measured through the statistical probability that consumers of electricity may be faced with the loss of their supplies due to insufficient generation. In the UK this is measured by the Loss Of Load Probability index (LOLP) representing the probability of the annual peak load exceeding the available generation. For example, in the GB system, the generation adequacy standard used to set the probability of peak load not being supplied at 9%. This was often interpreted as the likelihood of peak demand exceeding the available generation being at most 0.09, or that generation shortages should not occur in more than 9 winters in one hundred years. This calculation was based on the probability of there being insufficient generation to meet demand, however, the risk of interruptions will also be affected (and will increase) in the presence of a finite transmission network capacity (i.e. an optimally constrained network).

From a network perspective, an underlying philosophy of transmission network planning (for systems with conventional generation) is to ensure the adequacy (reliability) of supply. This centres on the requirement that transmission capacity between system boundaries should be sufficient to ensure that generators in remote areas are not unduly restricted from contributing to security of supply of loads (the basis of the GBSQSS proxy). On this basis, the average power transfers on the system at peak will be determined by the average local plant/demand balances. These power transfers can be obtained by scaling all generation throughout the system to meet the forecast peak demand (to take account of the generation margin). For example, under a central planning approach, this scaling factor would simply be the inverse of the plant margin – thus if the margin were 20% the scaling factor applied to generation would be 1/1.20 = 0.83.

In reality, the system is unlikely to require this "average" interconnection value at all boundaries across the whole system. This deviation from the average is allowed for by adding a margin to the planned transfer. In the GB system, the appropriate margin called interconnection allowance

[15] This describes the methods as developed in the recent report: STRBAC, G., PUDJIANTO, D., CASTRO, M., DJAPIC, P., STOJKOVSKA, B., RAMSAY, C. & ALLAN, R. (2007) Transmission Investment, Access and Pricing in Systems with Wind Generation. DTI Centre for Distributed Generation and Sustainable Electrical Energy.

was determined by observation of actual inter-area flows which allowed the construction of a relationship between the likely maximum required transfer and the generation and demand in the smaller of the two areas under consideration.

The risk (probability) that the transmission system capacity will be insufficient to meet the demand is quantified using the methodology for the reliability evaluation of interconnected systems (Billington and Allan, 1984). This risk reduces sharply with the increase in transmission capacity between the two areas. However, at a certain level of transmission capacity, the risk converges to a value that represents the minimum risk that such an interconnected transmission system can have under given conditions (i.e. there is a point at which increasing transmission capacity can no longer improve the probability of loss of supply).

This is illustrated in the 2 busbar system illustrated in Figure 2-7a. The sample system is divided into areas A and B. Both areas are characterized by the same conventional installed capacity (31GW, with availability factor of 0.85), and the same peak demand (25GW) and are connected by a transmission line of finite capacity. If generation outputs are scaled to meet peak demand, net generation will be 25MW from both A and B and average peak flow between the two areas is zero. However, it would be beneficial to have some transmission boundary capacity to enable sharing of reserve in both areas and increase overall system reliability.

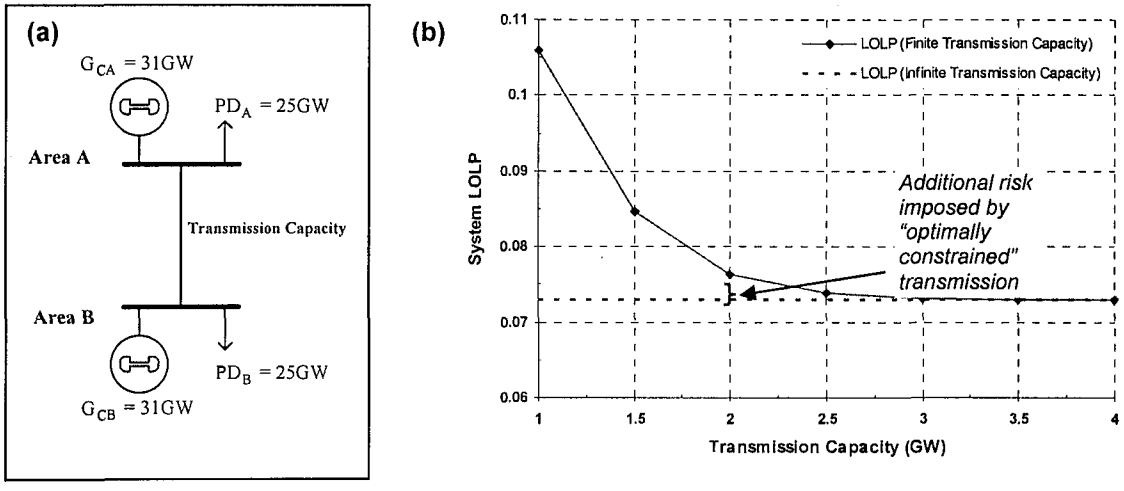


Figure 2-7: Example two-busbar system and calculation of system risk imposed by transmission capacity

Using the previously cited methodology for reliability evaluation of interconnected systems, Figure 2-7b shows how the risk of loss of load decreases with increasing transmission capacity as described above. If we apply the GBSQSS based rules for network design to this system the optimal level of interconnection is found to be 2GW (See NGET, 2004 for a full description of the interconnection planning methodology). So under traditional network planning guidelines,

interconnection of 2GW would be installed. This is only around 0.5 GW less than the capacity at which no further improvement in system reliability is seen.

So to quantify the additional risk of loss of load that a finite (optimally constrained) network imposes on the overall system we can see that this is around a 5% increase in system LOLP (from 0.073 to 0.077). In the context of whole system reliability, we can determine that the initial figure of 0.09 LOLP related to the probability of generation being insufficient to meet demand, is increased by 5% to 0.094 when the finite nature of the transmission system is included.

The implications of this finding are that the transmission system designed using the current standard specifies an optimally constrained network that balances the cost of system reliability against the cost of investment, with the outcome that only low levels of system LOLP caused by transmission network constraints can be tolerated under the current arrangements. The focus of the current standards is on sizing the network to allow fulfilment of peak demand requirements, which is facilitated by providing sufficient network for coincident peak output of connected generators.

2.4.2 *Regulatory arrangements and charging for long term access: system reinforcement costs*

Long term transmission access for generation is linked to transmission investment and administered through the Transmission Entry Capacity (TEC) product, so all generators wishing to connect and export to the transmission system must hold TEC. Connection to transmission is on the basis of "invest then connect", so necessary network reinforcements are made before connection is allowed and TEC is then issued[16]. For generators TEC represents the maximum allowable output from any given generator, at any point in time, and provides the generator with guaranteed, long term firm access rights for transmission. Generators holding TEC will be compensated by the System Operator if they cannot access transmission up to their purchased TEC capacity. For the System Operator, TEC is used as a proxy to determine transmission capacity requirements (and corresponding investment) to accommodate new generation into the network (i.e. to optimise constraints while ensuring adequate security levels).

Long term network reinforcement costs are recovered through Investment Cost Related Pricing (ICRP) that indicates the marginal cost of connection for generation (based on TEC) and derives

[16] Note that the System Operator cannot issue more TEC than there is transmission capacity available, so if there insufficient capacity available to connect a generator, connection (and the issuing of TEC) is delayed until network reinforcements have been carried out.

a locational cost element of the Transmission Network Use of System (TNUoS) charge. An additional non-locational (or "residual") element is then added for revenue recovery.

In order to achieve key pricing objectives of economic efficiency, National Grid Electricity Transmission (NGET), transmission system operators of the Great Britain transmission network, have developed a location specific network investment based pricing method. This method rewards users who reduce the demand for transmission investments (i.e. generators that are located in demand dominated areas and demand users located in generation dominated areas) and penalizes users who impose the need for transmission investment (i.e.generators that are located away from the load centres and demand located in demand dominated areas).

At present, most generation connected in the distribution networks are not exposed to these TNUoS charges (Ofgem and Dti, 2004). Generation in the distribution network that is under 100MW in capacity can choose to be a licence exempt generator. In doing so the generator waives the right to sign up to the Balancing and Settlement Code (which allows participation in the wholesale markets) and is not asked to be a signatory to the transmission Connection and Use of System Code (CUSC) (that brings with it mandatory control activities requiring the signatory to contribute to system operation functions). This means that licence exempt generation is not liable for TNUoS charges, as it effectively is not utilising the transmission network for export. Furthermore, for DG, being connected closer to demand (thus reducing the requirement for transmission) brings an additional advantage of the embedded benefit. For generators that have contracted to sell their output to an energy supplier with a presence in the same location (at the same Balancing Mechanism Unit (BMU)), their output can be offset against the supplier's total demand, reducing the net demand, and reducing the supplier's exposure to the demand TNUoS charge.

For distributed generators that want to export to the transmission network or take part in the various transmission related services there are two access products - the BEGA and the BELLA - that can facilitate this interaction.

- **Bilateral Embedded Generation Agreement (BEGA):**
  The BEGA is an agreement entered into between NGET and a CUSC user relating to a generating station (or other connections provided for in the CUSC) connected to a distribution system and the use of the GB transmission system. It identifies the relevant site of connection to the distribution system and sets out other site specific details in relation to that use of the GB transmission system. The BEGA confers use of system rights to a

generator (through allocation of TEC), allows utilisation of the balancing mechanism, and with all this exposes the generator to some use of system charges.

- **Bilateral Embedded Licence exemptable Large power station Agreement (BELLA)**
  An agreement entered into between NGET and a CUSC user relating to a generating station (or other connections provided for in the CUSC) connected to a distribution system and the use of the GB transmission system. Unlike the BEGA, the BELLA does not allocate any use of system rights to the generator or require a user to pay charges in accordance with the transmission charging methodology. Furthermore, the generators would not be required to become a BSC party and fewer elements of the Grid Code would be applicable.

These arrangements are relatively complex and involve DG interaction with both the DNO and TSO. They are contracts designed for single generators (usually those that are just under 100MW) and it is unlikely that generators at the smaller end of the scale would find it financially viable to take on the administration of one of these arrangements. Because they are individual arrangements between the generator and the System Operator(s), both the BEGA and the BELLA result in gross treatment of DG access to transmission (fundamentally treatment using the TEC approach, although DG holding a BELLA does not have to specify TEC directly). This means that through these products each DG is allocated an individual maximum capacity allowance on the transmission system and no account is taken of time of use of the system or diversity in output between the DG with a BEGA/BELLA and other generators (or demand) in the network[17].

2.4.3 Transmission network short term access: constraint management

In the early 1990's, privatisation and liberalisation of the electricity sector in the UK led to development of competitive markets in generation and supply, but the activities of transmission and distribution, although privatised, were identified as natural monopoly functions and maintained as separate, regulated entities. The British Electricity Trading and Transmission Arrangements (BETTA) approach maintains the situation adopted by NETA of decoupling energy and short term transmission access. Under BETTA, there is unconstrained (non-location

[17] A discussion to initiate the development of enduring transmission arrangements for DG was headed by Ofgem in September 2005 OFGEM (2005a) Enduring transmission charging arrangements for Distributed Generation: A Discussion Document. London, Office of Gas and Electricity Markets, OFGEM (2006b) Enduring Transmission Arrangements for Distributed Generation: Further Thoughts Document. *Further Thoughts Document.* London, Office of Gas & Electricity Markets.. Here the concern was raised that DG was not adequately exposed to transmission charges, and that this could result in cross subsidy between transmission and distribution connected generation, creating the potential for perverse incentives for generation to connect at sub-transmission levels just to avoid charges. The consultation identified the growing penetration of DG as a stimulus for action on developing transmission arrangements, citing in particular the concern voiced by the System Operator that some distribution areas with particularly high penetration of DG could now be exporting back to the transmission network at particular times of the day without specific access rights NGET (2005a) Enduring Charging Arrangements for Distributed Generation: Response to Ofgem Discussion Document September 2005. National Grid Electricity Transmission..

specific) energy trading in competitive wholesale energy markets. So, in the short term (real time operation) transmission availability and constraints resulting from contracts formed in the energy market are managed through the balancing mechanism.

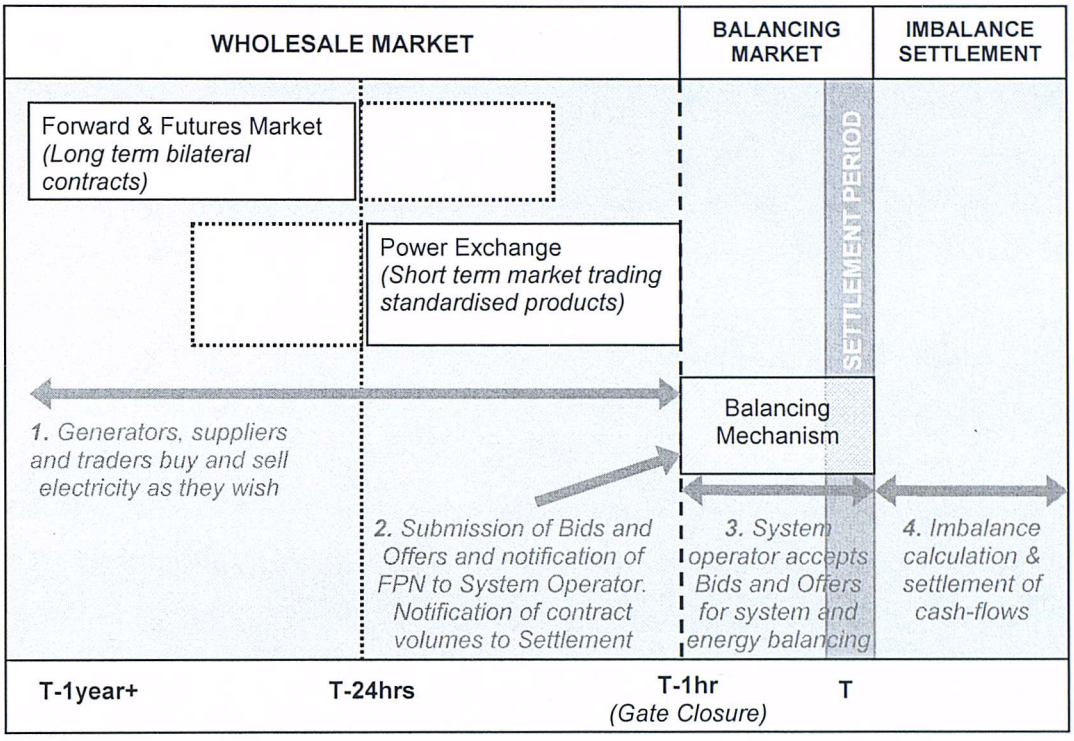


Figure 2-8: Operation of the UK Electricity Market during a single Settlement Period (NGET, 2007a)

Figure 2-8 illustrates the operation of the UK electricity market and the positioning of the balancing mechanism. Trading occurs for delivery of contracts in half hour Settlement Periods throughout the day (each day is composed of 48 periods), and contracts for each period can be agreed up to one hour before delivery (Gate Closure). The Market is split into three discrete periods; the Forwards Market and Power Exchange, the Balancing Market (including the Settlement Period) and Imbalance Settlement.

At Gate Closure, all market participants are obliged to submit Final Physical Notifications (FPN) to the System Operator, informing the Operator of their expected generation or supply position in the subsequent Settlement Period. Any Party wishing to transact in the Balancing Market must submit bids (to decrease generation/increase demand) and offers (to increase generation/decrease demand), along with their Final Physical Notification. In parallel with this all Parties must also submit information on their contracted positions prior to Gate Closure to the ECVAA (Energy Contract Volume Aggregation Agent).

Management of network access and resolving constraints (caused by the non-location specific trading of energy in the wholesale markets) is carried out by the system operator close to real time. Under normal operating conditions, the system operator will begin to balance the system using Physical Notifications submitted by transmission connected generation. These notifications are submitted a day ahead (Interim Physical Notifications) and an hour before real time (Final Physical Notifications) by all market participants, which indicate to the system operator the physical flows on the network. The system operator will then use a combination of bids and offers from the Balancing Mechanism and dispatch of scheduled response and reserve services to ensure that supply and demand are continuously matched at all times and that any system constraints are optimally resolved. Under emergency situations the system operator has a range of additional system service contracts that it can call on at very short notice. The ability of generators to maintain a level of flexible and controllable capacity in the balancing mechanism is of key importance to providing these services to the system operator.

2.4.4 *Regulatory arrangements and charging for short term access: allocation of constraint costs*

The cost of short term network access is expressed in the transmission system constraint costs. This is the cost of constraining off and re-dispatching generation to resolve network constraints that arise because of un-restricted trading of energy on the wholesale markets. This cost is essentially the discrepancy between the amount paid to generators constrained on, and paid out by those which are constrained off. In a perfect system this will be equivalent to the fuel cost differential between generators. The system constraint costs are separated from energy imbalance costs[18] (where generators have over/under produced according to their contracted volumes) and the resulting Balancing Service Use of System (BSUoS) charges include the cost of losses which are shared equally throughout all market participants (generation and demand) according to their traded volumes. Because these costs are socialised across all system participants there is no locational element to the charge, users are not exposed to the costs of short term network access and the short term value of transmission access remains hidden.

[18] For every half hour Settlement Period market participants must ensure that their contracted volumes match their metered output (or demand) as closely as possible. Parties causing the system to be in imbalance are penalised with a dual price cash-out mechanism that charges market participants according to whether they have left the system long or short of power during the contracted period. Those causing the system to be short (i.e. a deficit of power due to under-production or over-consumption) are obliged to pay the System Buy Price (SBP) on the volume of imbalance created. Parties causing the system to go long (i.e. a surplus of power due to over-production or under-consumption) are paid a System Sell Price (SSP) for the excess power. In most instances the SBP is greater than the average spot price for that period and the SSP is less. To manage this imbalance risk, market participants undertake balancing activities. Typically, this occurs in the power exchanges, where participants fine tune their positions close to real time by contracting with generators or suppliers to adapt their position. This type of balancing only takes place before Gate Closure. At Gate Closure, all parties must submit a full record of their contracted volumes for the same Period; during Imbalance Settlement, this data is then reconciled with final metering data to determine each party's imbalance position.

2.4.5 Challenges to transmission network operation and development from transmission connected renewable generation

Challenging the appropriateness of the current GBSQSS

Markets and regulatory frameworks are developed to achieve optimal allocation of resources in particular systems; they are tailored to meet the needs of the incumbent technologies and operating philosophies. As the profile of technologies changes, e.g. with the penetration of DG and renewables, market and regulatory arrangements may accordingly also need to change to reflect the changing characteristics of the system. The current system has been developed in the context of large-scale transmission connected generation. As demonstrated above, the standards that guide the design and development of the system, the GBSQSS, are a proxy to deliver the optimal development of this system.

However, with the penetration of new, non-conventional generation technologies and a changing physical system, it is possible that this proxy will no longer be suitable for the system that we are moving towards. Recognition of the issue of spatial and temporal differences in renewable and distributed generation versus conventional generation is going to be vital in developing an optimal system that rewards generators appropriately, sends the correct signals regarding location and timing of output, and does not discriminate against any participant. For example, the role of reliability in network standards is likely to change. Previously a driving factor in network design, as identified in section 2.2.3, new generators entering the system invariably have a low capacity credit and are less able to make a contribution towards system reliability.

Furthermore, there are entirely new technologies entering the system that require a complete reappraisal of the operation and investment regime for transmission. Offshore wind generation requires the construction of a new transmission system to connect generation units back to the shore. These offshore units are characterised entirely differently to onshore wind, and conventional generation. There is no demand offshore, cabling technology is different and considerably more expensive, even the structures for development of the roles of System Owner and Operator and the interaction with the onshore network operator are entirely new. Although offshore transmission questions are not dealt with further in this research, this highlights the materiality of the present issues in transmission. The system is undergoing material physical change that will necessitate reconsideration of the central tenets of its operation and development. (For further discussion of the issues around development of the offshore transmission network roles and responsibilities see (Tutton, 2007) and for a comprehensive view on the progress with offshore transmission grid codes and GBSQSS see (Ofgem, 2007b)).

Given this importance of spatial and temporal issues, and the difference between conventional and non-conventional generation in this respect, it is apparent that the new system will have different requirements. The optimal balances between investment in capacity and management of operational costs will change and this needs to be reflected in new GBSQSS or some alternative and new proxy. Standards are the starting point between the TSO and system users on how the network should develop and they should not ignore (or inappropriately oversimplify) what users want. In a competitive market environment user choice is the key; if the current standards are to remain, they must evolve to reflect this and represent the increasing number of options in system development.

Maintaining the separation of energy and access

The current market arrangements under BETTA maintain a separation of energy and access, so that energy is sold in the wholesale markets without including the value of short term network access in the wholesale price. Whilst this is an approach that has not been detrimental in the current system where a homogenous group of generation units use the system in a similar and predictable fashion, constraint costs are low and the impact of location on the value of power is minimal, the future system could change this. New renewable generation is entering the system in potentially very large amounts. Because of the availability of the wind resource this new generation must be sited in an area of the network that is already experiencing congestion, and it will exacerbate the already apparent north-south flow of power.

It is likely that the value of access in these already constrained areas could change quite significantly (with time of use of the system and weather conditions) and that this could massively impact the value of energy from particular locations. Failure to reflect these differences in value that change with both location and time, and to pass the costs on to the users of the system that impose them, could result in a non-competitive environment of sub-optimal development and considerable cross-subsidy between users. It also prevents certain systems users (primarily demand users) from receiving cost reflective price signals that could stimulate efficient responses in terms of system operation and promoting optimal long term development in non-network solutions (i.e. demand response could mitigate reinforcement).

2.5 Distribution network access

The following section explores fundamental principles and regulatory frameworks behind the operation and development of the distribution network. The legacy of passive operation means that all short term access issues encapsulated in the operational activities of the network are resolved at the network planning stage, so the concept of short term access and associated

frameworks is not well represented in the conventional distribution system. As such this analysis focuses on the long term network access arrangements and charging frameworks that dominates the network access discussion in the distribution network.

As in the previous section, the analysis then discusses the impact of penetration of distributed generation into this framework and explores how various drivers (location in the network, density of installations, diversity, pattern of generation etc.) are likely to influence the evolution of the regulatory framework that supports the distribution networks.

There is an extensive body of research on the impact of the regulatory regime at distribution level, particularly with reference to how this incentivises or acts as a barrier to connection of DG. The aim of this review of distribution network access is to identify the high level principles that drive the approach to network access, with a view to determining their impact on competition as reflected in cost reflectivity of access for system users. The detail of monopoly regulation and development of incentive schemes to reflect e.g. policy interest in encouraging low-carbon generation is out of the scope of the research presented in this thesis. For more extensive reviews of the impact of regulatory incentive schemes see work carried out under the SUSTELNET (Connor and Mitchell, 2002, Scheepers and Wals, 2003) and DG GRID programmes (Gomez et al., 2007, Bauknecht et al., 2007)

2.5.1 *Distribution network long term access: network design, security standards and investment*

In this section the key design and investment philosophies that have led to the development of the existing distribution network infrastructure are discussed. The main investment drivers in distribution network design are:

- Network security: the need to satisfy network security requirements by investing in adequate network capacity
- Network losses: the need to strike an optimal balance between operating costs and network investment; and
- Service quality expenditure required to improve network performance indicators e.g. Customer Interruptions (average number of interruptions per 100 customers per year) and Customer Minutes Lost (average duration of interruptions per customer per year).

The overarching theme running through all these drivers and through the design and development of the distribution system is that all the issues pertinent to distribution network access have to date been dealt with according to the requirements of demand. Because

conventional distribution networks are passive operators, they have the sole function of serving demand; and original grid codes and standards have been developed to uphold security of supply for demand alone, without consideration for the impact or needs of generation in the network. Historically, this has been an appropriate approach because the penetration of DG in the system has not been significant enough to cause disruption.

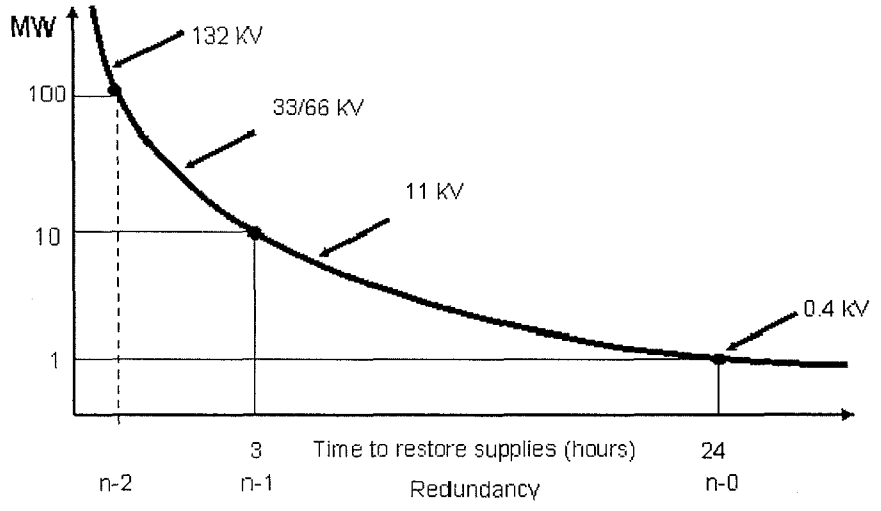
Network Security

Delivering security for demand

The passively managed distribution networks are usually planned to accommodate single direction power flows. The primary assets (transformers, switchgear, overhead lines and cables) on passive networks are specified to accommodate a set of pre-specified operating conditions, ensuring the technical parameters of supply (e.g. voltage and power flows) are maintained within statutory and safe limits, without the requirement for proactive network monitoring and reconfiguration. This is a key feature of the overall philosophy of network operation and investment and is reflected in the distribution network planning standard (Engineering Recommendation P 2/6, adapted in 2006 from the previous P2/5 document) that is a part of the licence condition. The standard is focused on requirement associated with network security of supplying peak demand[19]. The general aims of the security standard are to provide "sufficient plant and other resources to provide and maintain an economic level of reliability of supply to the consumer"; it proposes that "the main factors affording a gauge of reliability of supply are frequency of interruption, duration of interruption and value of the service not provided"(ACE, 1979).

ER P2/6 broadly defines the network design philosophy and requirements to comply with the security standard. The level of security in distribution networks is defined in terms of the time taken to restore power supplies following a predefined set of outages. Consistent with this concept, security levels on distribution systems are graded according to the total amount of peak power that can be lost. A simplified illustration of this network design philosophy is presented in Figure 2-9. For instance small demand groups (e.g. in the 0.4kV low voltage network) with less than 1MW peak, are provided with the lowest level of security, and have no redundancy (N-0 security). This means that any fault will cause an interruption and the supply will be restored only after the fault is repaired. It is expected that this could take up to 24 hours.

[19] It is notable that the ER P2/6 standard does not discuss levels of security that may be appropriate for generation.



Where:

n-0 = no redundancy in security (must wait for repair of network);

n-1 = one level of network redundancy; and

n-2 = two levels of network redundancy.

Figure 2-9: ER P2/6 restoration time philosophy relative to peak network demand/network voltage level

For demand groups between 1MW and 100 MW, although a single fault may lead to an interruption, the bulk of the lost load should be restored within 3 hours. This requires presence of redundancy, as 3 hours is usually insufficient to implement repairs, but it does allow network reconfiguration activities. Such network designs are often described as providing n-1 security. For demand groups larger than 100MW, the networks should be able to provide supply continuity to customers following a single circuit outage (with no loss of supply) but also provide significant redundancy to enable supply restoration following a fault on another circuit superimposed on the existing outage, i.e. n-2 security.

Recognising the security contribution from DG

In the UK recognition of the contribution of DG to securing load has recently led to a change in the Engineering Recommendation (from P2/5 to P2/6), a methodology for updating the standard has been developed and adopted to take into consideration the contribution of new generation technologies (Allan et al., 2004). The methodology proposes a calculation of the capacity of a perfect circuit, which, when substituted for the DG, gives the same level of expected energy not supplied. The capacity of this ideal circuit is a measure of the capacity contribution of DG.

The standard developed can deal with both non-intermittent and intermittent generation technologies. Table 2-3 and Table 2-4 are taken from the new standard to illustrate the features and the magnitude of the contribution to network security that is associated with various forms of DG. For non intermittent generation, availability of individual units and the number of units

are key driving factors of the contribution that DG can make. The average values of actual availabilities for each type of non-intermittent plant are established and a security contribution evaluated. As expected, units with higher availabilities make larger contributions to security than units with lower availability. Furthermore, a single unit makes less contribution than a capacity-equivalent group of multiple units. Both tables illustrate the "F Factors" for each characteristic technology, this represents a scaling factor to calculate the level output that can be guaranteed against the total capacity of the generator.

For intermittent generation, such as wind and hydro, the average winter output profile and the minimum persistence time T_m is used. Persistence time is the period of time for which intermittent generation will need to operate continuously at or above a certain output level in order to support the demand and provide system security. The minimum persistence time is dependent on the system state and conditions (such as switching, repair, and maintenance processes). As shown in Table 2-4 below, the longer the time period over which a certain level of output is expected the lower the capacity contribution of the intermittent generator. For example, if the time over which the support is required is 30 minutes, 28% of the installed capacity can be "relied upon" while this value reduces to 11% for the time period of 24 hours.

Type of generation *(average availability, %)*		**Number of generation units**									
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10+**
Landfill Gas *(90)*		63	69	73	75	77	78	79	79	80	80
CCGT *(90)*		63	69	73	75	77	78	79	79	80	80
CHP	Sewerage: spark ignition *(60)*	40	48	51	52	53	54	55	55	56	56
	Sewerage: Gas Turbine *(80)*	53	61	65	67	69	70	71	71	72	73
	Other CHP *(80)*	53	61	65	67	69	70	71	71	72	73
Waste to Energy *(85)*		58	64	69	71	73	74	75	75	76	77

Table 2-3: F factors in % for non-intermittent generation

Type of generation		**Minimum persistence time, T_m (hours)**							
		0.5	**2**	**3**	**18**	**24**	**120**	**360**	**>360**
Wind	Single site	28	25	24	14	11	0	0	0
	Multiple sites	28	25	24	15	12	0	-	-
Small hydro		37	36	36	34	34	25	13	0

Table 2-4: F factors in % for intermittent generation

Rewarding security contributions from DG

The rate of deployment of new distributed generation has remained relatively low since the implementation of ER P2/6 and no examples of distributed generation being used to secure Demand Groups have been identified. The lack of an established framework by which DNOs can reward generators for the provision of security contributions has been identified as a barrier and the current regulatory arrangements do not incentivise DNOs to make payments to generators. However, examples of DNOs procuring short term network security contributions from distributed generation were identified in the Dutch electricity market with generators being rewarded accordingly.

Quality of supply

Evolution of quality of supply performance in UK

Historically, quality of supply was regulated through the Guaranteed and Overall Standards of performance, using the performance indicators of Customer Interruptions (CI) and Customer Minutes Lost (CML) to measure the number of times customers lost service and the duration of the outage. Guaranteed Standards entitled consumers to compensation for receiving service below specified thresholds, while the Overall Standards monitored system level performance for each distribution company. Consequently, significant progress was made with regards to quality of supply.

The Information and Incentive Project was first introduced in April 2002 to set each DNO with specific targets for the quality of supply measures CI and CML based on individual DNOs' past performance. The initial IIP incentive scheme linked the quality of supply performance of DNOs to their allowed revenue (+/-2% of exposed revenue). This included mechanisms that penalised companies for not meeting their quality of supply targets and rewarded companies that exceed them. The introduction of the IIP resulted in further significant improvements in the quality of supply indicators and on network reliability performance in Britain.

Impact of IIS on network design and operation: System design and performance

As discussed earlier, ER P2/6 does not require network redundancy at low voltage (LV) and the duration of outages caused by LV faults is determined by component repair and replacement times. High Voltage (HV) networks are generally designed as meshed but operated in radial mode. The consequence of this design feature is that, generally, faults on the HV network will cause interruptions to some customers although the network configuration enables restorations to be implemented rapidly, within 3 hours, as required by ER P2/6. Networks operating at EHV are designed to be operated in a meshed configuration, so that single faults would not normally lead to an interruption to end customers.

These network design practices, driven by ER P2/6, effectively determine quality of service characteristics as experienced by end customers. IIS targets incentivise DNOs to reduce the average number of CI/CMLs on electricity distribution networks. Consequently, DNOs evaluate the regulatory target and incentive framework to determine the most cost effective methods of achieving quality of supply improvements. To date, DNO IIS related investments have sought to address the most effective 'quick-wins' in terms of performance improvement. Since implementation, the IIS has focussed DNO attention upon HV network automation and remote control (and to a lesser extent LV) networks. After exhausting such HV automation opportunities, it would be logical to address LV network performance improvements although such investments may be more costly due to requirement to reconfigure (and potentially duplicate) primary assets.

This attention has resulted in many LV and HV circuits being designed beyond the ER P2/6 minimum requirement. By contrast, there is less scope to effect IIS performance improvements through investments in EHV networks. This is attributable to the high reliability of such networks arising as a consequence of ER P2/6 redundancy requirements and extensive network automation. Quality of supply related incidents arising from EHV networks are therefore regarded as low probability: high impact events relative to HV/LV networks. Consequently, it can be concluded that the IIS has been particularly influential with respect to HV/LV network design, whereas EHV design has tended to be driven by planning standards.

A potential future risk associated with reliance on an incentive scheme for network design is that a disproportionate focus could be placed on short term network performance. Such incentive arrangements adequately address frequent low impact interruptions. However, such arrangements do not adequately address low probability high impact events typified by the larger Demand Groups. Consequently, over-reliance on quality of supply incentive schemes to influence network design could be to the detriment of long term EHV network planning and security of supply to customers.

Incentives to connect distributed generation

In April 2005 Ofgem introduced an incentive scheme for DNOs in relation to the connection of distributed generation. Under the scheme, costs incurred by the DNO when providing network access to distributed generators are partially (80%) passed-through and potential shortfalls are compensated through the application of a supplementary £/kW revenue incentive of £1.50/kW for all DNOs (except for the North of Scotland) (Ofgem, 2004a). This arrangement was devised to incentivise DNOs to actively facilitate the connection of all forms of distributed generation. From a DNO's perspective, increasing the capacity of distributed generation connected to a DNO network also increases the DNO's corresponding revenue allowance.

Network Losses

Minimum planning requirements and lifecycle costing

The Losses Incentive Mechanism has been put in place to encourage DNOs to take steps towards reduction of losses. The incentive rewards DNOs with a flat rate per unit of losses reduced from a baseline derived from historical performance (DNOs are also penalised by the same amount for loss increases); the current reward rate is £48/MWh (Ofgem, 2004b). However, typically, losses have not been a key driver of network investment activity, although the UK electricity losses at distribution average around 7% per annum and are the highest in Europe (Ofgem, 2003a).

Network design according to the minimum planning standard is focused on least cost investment to meet peak demand, and although this standard does now include the contribution of generation to securing demand, this approach does not encourage a whole lifecycle approach to optimising network investment against ongoing running costs. In the case of losses, recent work indicates that it can be economically efficient to install some network components (e.g. cables) rated at 5-10 times the demand requirement when evaluated over 20 year time horizon, especially for LV and HV circuits. However, under the current approach the Net Present Value (NPV) of ongoing operational costs is not sufficiently significant to warrant their consideration alongside (or over) the upfront costs of installation.

2.5.2 Regulatory arrangements and charging for long term access: Distribution Use of System charges

To evaluate charges for the use of distribution networks, the majority of DNOs use a methodology known as the Distribution Reinforcement Model (DRM). This method is employed to evaluate the long run marginal cost of expanding, maintaining and operating the distribution system. This is achieved by calculating the network cost of adding a 500 MW load on the system maximum demand.

These costs are then allocated across voltage levels and customer groups such that the resulting Distribution Use of System (DUoS) charges are somewhat cost reflective. This is achieved by identifying the contribution of each customer group to the long term distribution system cost.

The resulting tariff takes the form of maximum demand and/or unit related charges. Maximum demand charges are used for levels of the system close to customers. This is based on the argument that customers will occupy fully the capacity of the local network to which they are connected. These charges are usually expressed in terms of £/kVA/month. On the other hand, unit based charges in £/kWh reflect the impact on the network cost further up the system. This

approach is supported by the argument that the customer individual maximum demand is less likely to coincide with the system maximum demand. Although the tariffs are designed to be cost reflective a number of simplifying compromises are made in the implementation phase.

It is important to bear in mind that distribution use-of-system tariffs have been developed for customers who take power from the network rather than for customers who inject power into it (i.e. generators).

2.5.3 Challenges to distribution network operation and development from distributed generation

The electricity distribution networks of Britain have delivered secure and reliable supplies to customers. This performance is directly related to the network planning, design and operating practices of the DNOs. Consequently, it can be inferred that the existing standards and regulatory incentive arrangements have been effective in delivering secure and reliable networks to date. The key issue going forward is how this framework needs to evolve to continue to deliver efficient and optimal operation and investment for the future sustainable energy system?

Developing network access arrangements for generation

As noted above, the primary feature of the current network access arrangements for the distribution is that they have been developed to serve the requirements of demand alone. Because of the historical lack of generation connection in the distribution network and the passive unidirectional operation philosophy, the driving factor in development and design of the networks has been in securing demand and ensuring quality of supply to demand customers.

The first and most relevant challenge to distribution access arrangements therefore is the need to augment the emphasis of the current arrangements to include consideration of the requirements of demand in network operation and development. Without this consideration, as the penetration of generation grows in the network the current standards will be increasingly ill-equipped to direct the development of an optimal and cost effective network.

As an example, the ER P2/6 does not address the security of power transfers originating from generation. Because of the historical demand-only focus, currently DNOs are not required to provide a particular level of security to generator customers. Although the adaptation of the P2/6 methodology to include the contribution of generation in securing demand was a significant step forward in recognising the contribution of DG to network conditions, this still maintains the demand focus, and makes no mention of the security requirements of DG.

Although not a material problem in the current system, offshore wind generation highlights a potential problem with this approach.

A number of the new offshore projects will be coming onshore with a point of connection in the distribution network rather than directly to the onshore transmission network. This means that distribution networks may be required to transfer energy between transmission operators. In such circumstances, the applicability of the offshore Security and Quality of Supply Standard could be undermined in the absence of requirements to securely transport the power flows from such generation across distribution networks. As the current arrangements may not provide sufficient certainty for the developments in offshore wind, it will be important to understand these requirements and to quantify the appropriate levels of network security to transport the output from generators. A possible development path would be to review the existing industry codes, practices and governance procedures followed by development of an SQSS for onshore distribution networks and a corresponding industry code.

DUoS for generation

A further example of this omission of generation from the distribution access arrangements is seen in the Distribution Use of System (DUoS) charging methodology. Although consultations have been underway for some years to amend the charging methodologies to reflect the impact and contribution of generation, the majority of methodologies in use are still based on the historical demand-led approach. The impact of generation on distribution networks (in terms of costs and benefits) is site specific and it may vary in time. It will also depend on the availability of the primary sources, a factor important for some forms of renewable generation, as well as on size and operational regime of the plant, proximity of the load, layout and electrical characteristics of the local network, etc. It is not, therefore, surprising that the relatively simplistic DRM tariff structure, with network charges being averaged across customer groups and various parts of the network, cannot reflect the cost impact of distributed generation on distribution network.

It should be noted that DRM tariffs also have no real ability to capture the impact of multi-directional flows (caused by the presence of distributed generation) and cannot deal with the temporal and spatial variations of cost streams. Discussions to adapt this charging framework and move towards the transmission approach of long term investment based pricing that reflects the cost and impact of generation as well as demand on a locational (and time of use basis) are currently underway. Two methodologies have been proposed (Strbac and Mutale, 2006, Li et al., 2005), both of which are being taken forward in the ongoing consultation on the DUoS pricing arrangements. In brief, the approach proposed by (Strbac and Mutale, 2006) takes a

reference network approach to pricing, pricing use of the system according to a reference network representing the optimal configuration of the network as per the approach proposed in (Farmer et al., 1995). This sends price signals to generation and demand which indicate optimal configuration, connection location and use of the system. The alternative methodology proposed by (Li et al., 2005), charges users on the basis of system "headroom" rather than on an optimal system configuration. Where there is sufficient headroom in network capacity to allow operation the network charges are limited. As the headroom is reduced charges increase to signal the need for investment or non-network solutions to maintain system integrity and economically efficient operation. Both approaches have been designed to deliver a greater level of cost reflectivity in charges that reflects the equal and opposite impact of demand and generation on the network. The important factor in each methodology is that this is done through reflection of time of use and location on the network; in distribution, (even more so than transmission), these parameters heavily influence user requirements for network access.

A final consideration in the use of DG to provide network services is on the implication of using stochastic generators to provide system support and solutions to network problems for DNOs. This is a fundamentally different approach from the current method of providing system services which rely on network solutions (i.e. installing more network capacity, switchgear etc.) to reduce faults, ensure adequate security for demand etc. Using DG, some of which are inherently stochastic in nature or have limited availability, will change the level of certainty with which services can be delivered. Although this can be accounted for to some extent (the ER P 2/6 calculations on the contribution that generation can make to system security do account for availability and unreliability) the risk level of using DG is materially different to the network alternative (Ilic et al., 2007). By using DG for solving network problems DNOs will have to evaluate the risk and cost of non-delivery of service. This is not only a shift in the way that DNOs currently evaluate solutions to network problems, but also creates potential incompatibility with the Quality of Supply incentive approach to regulation of the DNOs. The current approach to incentivising quality of service is about rewarding DNOs that reduce customer interruptions; as an example, using generators to secure demand may increase faults or will at least will change the risk profile (and consideration of risk) associated with the likelihood of faults. So in terms of balancing the costs of using DG versus network solutions this will also have to include a calculation of risk of non-delivery of services and the cost implications that this has for the quality of service/supply indicators.

Active networks

Although this will not be taken further in the rest of this research, the potential for active distribution networks and "smart grids" is also receiving significant attention. In the UK the two

Research and Development programs; Registered Power Zones (RPZ) and Innovation Finance Initiatives (IFI) have been initiated as part of the IIP. These programs incentivise DNOs to look for new ways to "connect and manage" DG and to integrate the resource effectively into the network (Ofgem, 2005b, Ofgem, 2004a). There is also a number of initiatives and projects in Europe and the US pursuing the development of more active networks. Programs such as the Intelligrids initiative are trying to take advantage of and develop existing ICT infrastructures at a devolved level to interconnect large numbers of smaller generators and bring an increased level of "intelligence" (EPRI, 2003, EPRI, 2004). The SmartGrids initiative promoted by the European Commission is also operating along the same lines, in developing a vision for the management of integrated energy resources and networks that would also be compatible with the active network management approach and a greater integration of DG (CEC, 2006b). And finally the GridWise programme in the US is working to accelerate and optimize system performance through greater use of ICT and integrative approaches to system operation (USDoE, 2003). The overarching regulatory framework and principles to support this active and integrated approach are discussed in more detail as part of the SUSTELNET project (Bauknecht and Leprich, 2004).

2.6 Conclusions and implications

This chapter has identified the main characteristics of the conventional system, and proposed a high level structure for the future, sustainable power system that may evolve in the short to medium term. The review of the conventional system has included an overview of the current access network arrangements and draws out the main differences in network access between transmission and distribution. It identifies points of friction where the penetration of new, non-conventional generation technologies is most likely to cause investment and operational challenges. For the transmission system, originally installed with the primary function of allowing generation to reach demand, access arrangements have always focused on generation, albeit conventional generation. The challenge to transmission network access comes from the penetration of non-conventional generation that no longer fits the proxy set out by the current access arrangements. In common for both transmission and distribution is also the lack of attention given to short term access arrangements, encapsulated in the network operation timescale. The philosophy of the distribution network as a passive, demand driven activity means that access arrangements have been developed to serve the needs of securing demand. Although some innovative and advanced efforts have been made to integrate generation into the network at this level, the emphasis of this activity remains in securing load, rather than optimising network operation and investment for all system users, generation and demand.

Historical developments in the network access debate have mirrored the increase in materiality of renewable and distributed generation, the value of integration and the policy profile of low-carbon technologies. To illustrate this point, they core evolutions are listed below:

- Connection charging: movement from deep to shallow connection charges for generation in both transmission and distribution,
- Use of system charges: In transmission, long term location specific pricing has been implemented in TNUoS, and TEC (although flawed for a system with non-conventional generation) is a user specified requirement for transmission. Although a crude measure, it still provides additional level of transparency regarding users' requirements from the network. In distribution, there is ongoing debate for DUoS charges focussed around gradually improving cost reflectivity for generation (and working towards the transmission ICRP based long term pricing model) as this becomes a material presence in networks.
- Development of engineering recommendations: the active management recommendation, and the development of P 2/6 and its inclusion in the DNO standards (albeit in the context of the present demand dominated network access regime).
- Performance based regulation of DNOs, including the IFI, RPZ and DG incentive; and
- The next steps for the access debate as announced in the 2007 Energy White Paper (DTI, 2007 pg. 164): Following the Ofgem review of Transmission Access for Distributed generation, and feedback from parallel groups such as the Transmission Access Standing Group, A major review of transmission access is planned for the last quarter of 2007.

There is an ongoing requirement to bring access arrangements into line with the changing physical system. The recent changes have recognised that the current market is not necessarily providing a fair outcome for non-conventional generation or allowing cost effective operation and development. In most instances, the response to this has been incremental changes to the current regime that return the arrangements to an appropriate market proxy reflective of the physical system developments. This is having the effect of gradually moving the access arrangements to a more market based approach with each modification. Under this incremental approach, the whole system is slowly moving away from the long term approaches traditionally associated with central planning and the vertically integrated monopoly. Emerging is an approach grounded in conventional economic market regulation that begins with short term quantification of requirements and costs, to develop transparent and cost reflective arrangements for users.

Arguably, the issue of integration of renewable and distributed generation into the market and regulatory environment in the UK has become a mainstream issue. Understanding of the impact

and value of integrating these new technologies has become a part of the driving force that is now dictating changes in the regulatory and market structures that underpin the system operation and development. The questions that will now be tackled by the subsequent chapters address whether the current access arrangements are fit to cope with this changing physical system. This chapter has raised a number of challenges facing the current regulatory and market framework for network access; building on this the following chapters will assess the impact and requirements of the new system, and evaluate whether the existing arrangements remain fit-for-purpose. This chapter also raises for discussion the issue of whether the current approach to development of competitive market based arrangements for access is appropriate. At present the arrangements are being taken forward in incremental steps, reacting to identified challenges from the changing physical system. Whether this approach is sufficient to respond to material change in the generation mix remains open for analysis in the following chapters.

CHAPTER 3: Network costs and benefits of renewable and of distributed generation

3.1 Introduction

Realising the physical impact of new generation connecting to the network and understanding the economics behind their network access requirements is essential to facilitate the development of access arrangements which drive optimal operation and long term development of the networks. This chapter identifies the main impacts that connection of non-conventional generation has on the transmission and distribution network and explores the enabling technologies that can mitigate and moderate this impact.

An impact assessment methodology was developed to collate and analyse the findings from a series of quantitative studies on the impact of non-conventional generation on various aspects of the transmission and distribution networks. The approach considers the impact of renewable and distributed generation on the networks over both the long term investment horizon and on short term operational issues. It determines the requirement for additional capacity driven by these new technologies, and highlights their impact (positive and negative) on network constraints, losses and faults. In addition, the series of locational and operational characteristic drivers identified in Chapter 2 are elaborated upon and used as a qualitative measurement to identify the sensitivity of the key network impacts to different generation conditions.

To explore the extent of these impacts further, the chapter also identifies two key "enabling technologies": active network management and demand side participation. These two examples can alter the impact of non-conventional generation on the network and offer an alternative non-network solution to traditional network problems posed by the connection of new generation units. This chapter concludes by discussing the implications of the impact assessment for the network access requirements of a future sustainable system, and draws together these findings

with a summary of the access requirements for non-conventional generation in both transmission and distribution networks.

3.2 Impact assessment methodology

The methodology adopted for this chapter is a qualitative impact assessment approach to facilitate identification and discussion of the key impacts that non-conventional generation has on the transmission and distribution networks. The impact assessment draws on a number of quantitative studies from the Centre for Distributed Generation and Sustainable Electrical Energy (CDGSEE). The author was not involved in the quantitative modelling aspects of this work, but is interpreting the key findings from the individual reports against the impact assessment methodology. This approach facilitates the evaluation of a wide body of quantitative work and enables the many threads of the access debate to be drawn together.

The chapter presents the key findings from the highlighted report and illustrates this where appropriate with case study examples of characteristic generating technologies (e.g. wind generation, CHP, μCHP and PV). These findings are interpreted and evaluated using the devised qualitative impact assessment matrix approach detailed in the following sections and summarised in section 3.2.3. The assessment was undertaken over two timescales looking at the short term operational timescale, and the longer-term investment timescale. Building on this identification and classification of impacts, a series of drivers that moderate or increase the impact of renewable and distributed generation on the network are also explored. These drivers are elaborated in more detail in section 3.2.2 of this methodology. This assessment will provide insight into the differences between the network required to support conventional generation (and a traditional system), and that created through the addition of new renewable and low-carbon generation.

3.2.1 Definition of operational and investment timescales

The impact of DG on the transmission and distribution networks was evaluated over the long- and short term to capture the full range of operational and developmental activities undertaken by system owners/operators. For networks, transmission and distribution system operation and development are intrinsically linked. Investment in capacity as part of a long term programme has an impact on the short term activity of operation and maintenance of the network, and vice versa. An increase in the requirement for short term balancing activity, can for example, increase prices and signal the need for longer term investment. Evaluating the impact of new generation against both of these time horizons is essential. It allows characterisation of the full impact and value of renewable and distributed generation on the network, which leads to

development of efficient and optimal arrangements that ensure cost reflective treatment of all system users.

The assessment of costs and benefits over a short term timescale requires consideration of the effect of non-conventional generation on operational activities happening at or close to real time. In the instance of the transmission networks this is congestion management, and physical resolution of the economic dispatch schedule of generators that results from contracts made in the wholesale energy market. Because the UK market arrangements separate energy from location, power can be sold to any location in the network without consideration of the costs of network access to secure delivery of the contract. The physical constraints imposed by the transmission system must be resolved using the Balancing Mechanism, to curtail and dispatch flexible generation around constrained locations. From a short term cost perspective, losses and unplanned outages also form part of the operational costs of transmission alongside the cost of managing constraints.

For distribution networks evaluation of the short term operational costs and benefits includes consideration of the impact of DG on network losses in low voltage networks, voltage rise and fault levels in higher voltage networks.

Over the long term, the impact assessment considers the effect of introducing new non-conventional generation on network development, in particular on the need for investment in new capacity to reinforce the network. Long term development of the transmission network requires an understanding of how connection of new generation maps to investment in new capacity to reinforce the transmission network. In transmission, the network is built to satisfy requirements for system reliability, and economic efficiency and historically reliability has been the binding parameter driving design of the network. The impact assessment will explore the network capacity driven by DG in the instance of system designed for under both these parameters.

In the distribution networks most operational issues are dealt with at the design and planning stage of the network, the long-m investment timeframe. Specification of the network capacity is usually sufficiently high to support most operational possibilities whilst maintaining the passive operation philosophy adopted by the distribution network operators. The impact of DG on distribution over the long term timeframe will include consideration of the contribution of DG to network security (i.e. providing security to demand).

3.2.2 Drivers of non-conventional generation impact on the network

To contextualise the assessment of value and to provide a qualitative sensitivity analysis aspect to the impact assessment, a range of factors that may moderate or increase the impact/value of non conventional generation on the system were considered. As first identified in Chapter 2, the drivers of the impact that non conventional generation has on the system can be separated into two categories of operating and locational characteristics. These are then sub-divided into several factors which affect the magnitude of the impact on the transmission and distribution networks. Each of the impact-drivers is elaborated in more detail below:

Operating Characteristics

Pattern and time of output

As illustrated in Figure 2-3 (in Chapter 2), peak demand in the UK occurs in winter evenings, around 5.30pm. This is generally coincident with peak prices in the electricity wholesale market. Peak network flows usually coincide with peak demand, and peak wholesale prices, so conventional generation will try and maximise output during these high price/high demand periods. For new conventional generation entering this mix it is a reasonable assumption that it will also behave in this way, and that the network will require reinforcement to accommodate the new generator during peak demand. Therefore the additional capacity requirements imposed by an additional conventional generator on the system will be close to the maximum output of the generator.

The coincidence of new non-conventional generation output with system peaks will clearly affect transmission system capacity requirement. For many non-conventional technologies their pattern of output is not well correlated to demand, so many will not be generating at maximum output during times of system peak.

The correlation of peak demand and output varies with technology, for example:

- PV peak output will be in summer during daylight hours (Jenkins, 1995), and is thus unlikely to contribute to power flows during the winter peak,
- μCHP is likely to be operating during the winter peak to contribute to meeting household heat demands occurring around the same time (Cao et al., 2006); and,
- Wind generation, dependent on highly variable weather conditions, shows little correlation between peak output and peak network conditions (Oswald, 2006, Grubb, 1988).

Capacity credit

The capacity credit (or value) of generation technologies indicates the amount of existing plant capacity that can be displaced on addition of new generation to the system whilst still maintaining a given level of system reliability. This driver is important in guiding transmission network reinforcements in systems designed for reliability and can have an impact at distribution level where generation with high capacity credit is able to displace network capacity. Flexibility and controllability of generation is the key to maintaining the system frequency and integrity. The contribution that generation technologies can make to this will contribute to their capacity credit.

Whilst energy from new non-conventional plant can displace the energy generated by conventional plant on a one-to-one basis, the capacity credit of these new technologies (or any generation technology) to the generation capacity margin is calculated by the extent to which a technology can displace incumbent plant without compromising system reliability. Capacity credit is determined by technology contribution in relation to system peak, and is derived as a measure of a generator's contribution to the total system.

Many renewable and DG technologies have a low capacity credit. This means that they will displace proportionately more energy than generating capacity when introduced into the system, and some generating capacity may need to be retained to ensure that overall system reliability is not compromised.

Size of generation plant

Many DG and renewable generation technologies are too small to have a significant impact on some areas of the network when considered alone. However, as part of an aggregated group with a cumulative profile they can have a more significant effect both in terms of magnitude of response and also in controllability. In this instance some inflexible plant are able to benefit from inclusion in a portfolio with a percentage of flexible units (Ilex, 2001, Lampaditou and Leach, 2004).

(Distribution) network management philosophy

Active management techniques enable the DSO to maximise the use of the existing circuits by taking full advantage of generator dispatch, control of transformer taps, voltage regulators, reactive power management and system reconfiguration in an integrated manner. This active approach to system operation is reducing the negative impact of DG on the network, minimising requirements for reinforcement and reducing the cost of connection.

Locational Characteristics

Geographic location

At transmission level geographic location across the country is relevant because of its impact on power flows and subsequent contribution to network constraints in certain sensitive areas. On the UK system power flows are characterised by a north-south flow that is driven by the pattern of connection in generation and demand. Total installed generation and demand in the UK is spread across the country as illustrated in Figure 3-1. The overarching picture presented is that generation exceeds demand in Scotland, the North of England and the Midlands. In the South there is a small generation deficit with demand exceeding installed capacity by around 3GW. In the near-term future, generation capacity is expected to increase across all regions, maintaining the generation-demand pattern in Scotland, the North and the Midlands, and increasing generation capacity above demand in the South.

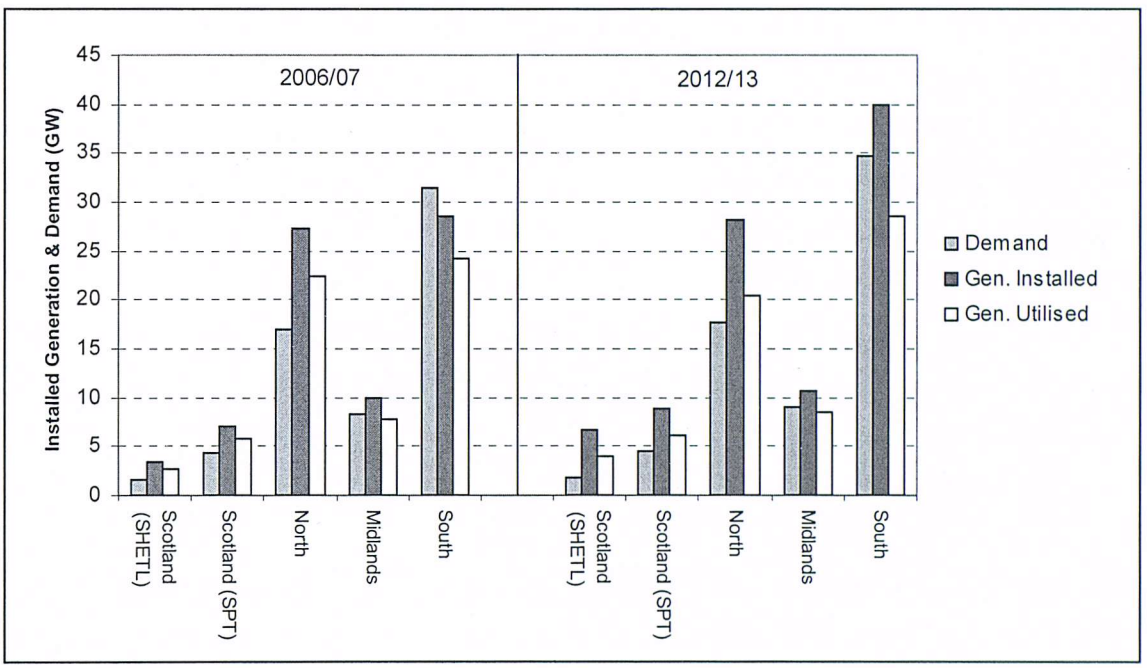


Figure 3-1: Total Demand and Installed/Utilised Generation (GW) in UK for 2006/07 and forecast for 2012/13 (NGET, 2007a)

However, this picture changes when considering the location of generation plant expected to meet this demand. Again, generation exceeds demand in the Scotland and the North, but much of the generation in the Midlands and the South becomes non-contributory causing significant net power transfers from the Northern parts of the system to the demand centres in the South, concentrating at the Cheviot Boundary (the point at which the old English and Scottish transmission networks were interconnected).

The positioning of new non-conventional generation, i.e. whether it is close to demand centres or installed in exporting areas, will impact power flows and so have a positive or negative effect

on transmission constraints and their associated costs. From a long term perspective, location will also impact on network reinforcement decisions and investment.

For distribution, location of generation within the network is of key importance to its impact on system operation and design. Generation installed in the high voltage network will have different impacts to the same unit installed at the medium or low voltage levels. For DG to have a positive impact on the network in terms of securing load and displacing network capacity, its location and proximity to load or weak network points is important. Rural and urban locations are also driving factors in determining how much impact any particular DG will have.

Diversity of network users

In a particular locality the requirement for network capacity will be determined not only by the addition of new generation into the mix, but also by the interaction between new and existing generation (and demand) in their use of the system. Diverse system users such as conventional and non-conventional generation, non-conventional generation and load, or different loads, are likely to have different requirement for network capacity and to use the system at different times. This diversity effect is clearly seen in the network capacity requirements for serving demand; figure 2-12 in the previous chapter illustrates the decreasing coincidence factor of load as the number of units considered is increased. The ramifications of this for network provision are that where a single load is being served, network capacity to meet the peak load must be provided. However, as more numerous and diverse loads are considered (e.g. as we move to higher voltage levels) the capacity required is less than the sum of their peak requirements.

So, in areas where there is significant diversity of system users, addition of new generation may not drive significant amounts of network reinforcement because of the diversity in their use of the system. Conversely, in areas of homogenous system use, such as a remote transmission connection to a wind farm with no local load, there is no diversity in output and no opportunity for sharing of capacity (as all users will wish to use the network at the same time – i.e. windy days) so the requirements for network capacity are likely to be close to the net peak outputs of all users.

Density of installations

The density of penetration of a particular technology in a local area will also drive impact, particularly in the distribution network that is already sensitive to location of generation. Penetration of new generators that are spread evenly all over the system, versus the same number of units in a single locality can have dramatic, even opposite, effects on the network.

A key example of this is the impact of increasing levels of μCHP and its impact on reverse flows and losses. Because of the high correlation between μCHP output and peak demand, penetration of CHP can initially have positive impact on the network. However, as penetration increases there is the risk of reverse power flows. For μCHP, this phenomenon may occur in the early morning when a low demand for electricity corresponds with high heat generation requirements. PV generation during the daytime in the summer holidays could be critical for exactly the same reasons (Strbac et al., 2006). The full impact of density of installations is also linked to diversity of system users and geographic location in the network (i.e. rural vs. urban, or high vs. medium/low voltage).

3.2.3 *Impact assessment matrix*

These assessment timescales and impact-drivers have been summarised into an impact assessment matrix as illustrated in Table 3-1. Using the matrix approach allows structured interpretation of the findings from the core reports. This facilitates a quantitative assessment on the impact of non-conventional generation on the network and its influence on network access.

Network & *Timescale* / **Drivers of impact**	**Transmission**		**Distribution**	
	Investment	*Operation*	*Investment*	*Operation*
Operating characteristics Pattern & time of output, Intermittency & variability, flexibility & controllability, capacity credit, Network management philosophy	*How much transmission capacity reinforcement does new wind generation drive in systems built for reliability and/or economic efficiency? How does DG drive or reduce the need for reinforcement?*	*How does non-conventional generation contribute to power flows & constraint costs? What impact does it have on losses and outages?*	*What impact does DG have on network security and how does this impact system design? How much network capacity can be displaced by DG? How much is needed to accommodate DG?*	*How does DG contribute to voltage rise effects and fault levels, and losses and what is the impact on service quality?*
Locational characteristics Geographic location Diversity of network users, Density of installations				

Table 3-1: Impact assessment matrix for evaluating impact of DG on transmission and distribution network investment and operation including defined drivers for impact

This impact assessment approach is applied in the following sections; it explores the physical impact of non-conventional generation on the transmission network (section 3.3) and the distribution network (section 2.5). Each section is framed by a description of the main network challenges presented (to the current UK system) by the connection of non-conventional

generation at the specified voltage level. Then assessment of the main impacts at the operational and investment timescales is explored for both the transmission and distribution networks. In both cases the headline network characteristics are identified, and the impact of non-conventional generation on these factors explored through qualitative discussion of the relevant drivers as identified in the impact assessment matrix methodology.

3.3 Transmission impact assessment

3.3.1 Introduction

As highlighted earlier, Scotland has more generation capacity connected to transmission than demand, so transmission power flows are north-south (to demand centres in the midlands and south east). Furthermore, the transmission network is already congested both in Scotland and along the main transmission lines that run into England. As highlighted in Chapter 2, 16 GW of applications for connection of wind generation are awaiting permission to connect to the transmission system, the majority of it in Scotland. Even if not all of these applications materialise, integration of this new capacity into the system will generate costs to the network. Firstly, because it is being connected at a point in the network that is already congested, and secondly because connection of a low-marginal cost generation technology like wind will change the economics of the network short term operation. The challenge at the transmission level is to understand these impacts of wind on the transmission system, and to then use this understanding of the physical system to determine whether the current transmission access arrangements result in a cost reflective representation of these impacts.

The transmission impact assessment uses the matrix approach described above to explore the impact of this additional wind generation on transmission operation to manage constraints and on network reinforcement. The presentation of the short term impacts of connection of wind generation in Scotland on the costs of constraints is derived from core power system economics theory overlaid with a discussion relating to the drivers for impact. The analysis of the long term impact of wind generation on driving network reinforcement uses the main findings from a recent CDGSEE study (Strbac et al., 2007) as its basis, alongside some additional literature reviews in the area.

3.3.2 Transmission operation: Constraints

This investigation of the impact of wind generation on the real time operation of the transmission system is restricted to an analysis of the impact of wind as it relates to transmission access; namely the system balancing required to resolve the physical network limitations of the

economic dispatch of generators derived from the energy only wholesale market. There are numerous other impacts that wind generation has on the transmission system operation such as the impact of intermittency in output that leads to imbalance between energy contracted and generated. This drives additional real time system balancing activity and is related to issues surrounding longer term system reliability caused by the displacement of energy but not capacity from incumbent plant. Although there are some synergies and links between these questions and issues of network access, a comprehensive review and analysis of these non-access concerns is out of the scope of this research; good overviews of these topics and quantification of the additional system costs that wind imposes in this respect can be found in a number of recent reports (Ilex and Strbac, 2002, Dale et al., 2004, UKERC, 2006).

Impact on transmission network constraints

In the operational timescale, the primary characteristics of concern that comprise the network operational costs are network constraints and losses. Of these two factors, network constraints are explored in detail in the following analysis at the expense of losses[20].

Non-conventional generation will contribute to network constraints according to its location in relation to the system demand centres. As explored previously, there are already North-South flows through the transmission network to meet demand in the Midlands and South East. Non-conventional generation locating close to the demand centres will moderate this flow and relieve congestion in the constrained parts of the network. Generation connected in the north of the country will contribute to and exacerbate these flows, and this applies for any generation technology (both conventional and non-conventional), although the extent of this impact will be depend on the drivers explored below.

Impact on constraint costs from connection of wind in Scotland

Adding wind in Scotland (if no conventional generation is retired), will contribute to transmission constraints; and although it will displace the most expensive generating plant from the merit order of dispatch, it will also be responsible for increasing the per-unit cost of constraints. The following simplified example illustrates this effect.

In the UK power is sold in the wholesale market without regard for location. The market is settled on a half hourly basis; so the contracts made in each settlement period represent a merit order of generation dispatch which should be the most economically optimal dispatch if the

[20] The impact of non-conventional generation on transmission losses is relatively straightforward, with generation sited closer to demand reducing losses through reducing the distance travelled on the network. The impact of losses on the cost of operation is a relevant factor, but it is not a cost element that fluctuates a great deal nor is it one likely to drive changes in access requirements over and above those initiated by network constraints.

network were unconstrained. The network is in fact optimally constrained, so these constraints must be resolved close to real time by constraining off (cheaper) generators in some locations, and dispatching other (more expensive) generators elsewhere to balance the physical system. The cost of constraints is essentially the cost of out of merit generation caused by network constraints preventing the dispatch of generators according to the contracts made in the energy-only wholesale market. This is equivalent to the differential between operating costs (essentially fuel costs) in the constrained and unconstrained system.

Adding wind generation into the system adds a zero (or low) marginal cost generator into the mix. This displaces the most expensive generation in the merit order, reducing the overall marginal cost of generation dispatch in the energy markets. The reduction in the unconstrained marginal cost thus increases the differential between the constrained and unconstrained systems, resulting in an increase in the overall cost of constraints. However, the addition of low marginal cost generation into the mix also reduces the overall energy costs for the systems as a whole (by displacing the most expensive generation from the merit order). The significance of the increase in the cost of constraints will depend on the benefits from reduced cost generation, and on the behaviour of generators in the balancing mechanism.

With regard to wind generation, it should also be noted that the impact on constraints will be mitigated by the fact that wind has a low load factor of around 20-40% in UK conditions (BWEA, 2007). So constraint costs per unit of wind capacity installed will be lower than if a similar low-marginal cost generator were connected with a higher load factor (e.g. nuclear). Correspondingly, the benefits from adding a low marginal cost unit to the generation mix will also be reduced.

Revenue flows, winners and losers from connection of wind

Observing the revenue flows and market activity for the incumbent Scottish and English generators reveals a little more about the activity underlying this process. Figure 3-2 illustrates a highly simplified GB system that presents England and Scotland as a 2 busbar system. The system has more generation than demand in Scotland which precipitates a north-south power flow. The link between England and Scotland is constrained at 2.5GW, limiting the export of generation from Scotland. In this example the most expensive generators, i.e. those displaced in the new merit order dispatch, are found in England. To alleviate congestion on the system the Scottish generators must be constrained off and English generators constrained on.

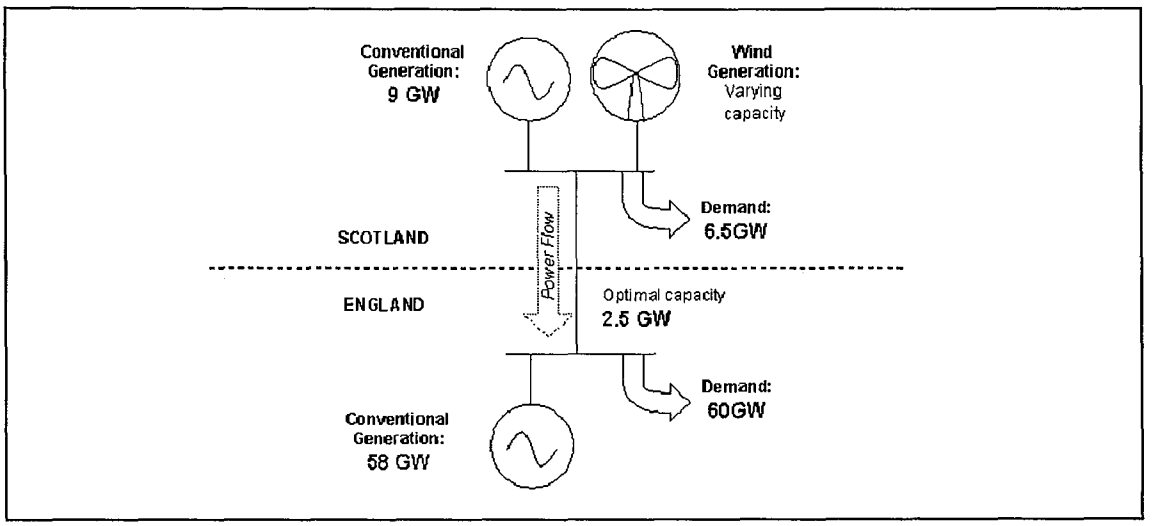


Figure 3-2: Simplified 2 busbar example of the GB system illustrating the England-Scotland transmission connection

Increasing the connection of wind generation in Scotland reduces total power traded by all incumbent generation in the forward market because it is displacing the most expensive of the incumbent generators. However, increasing volumes will be traded in the balancing mechanism to re-dispatch some of the displaced generation still required to resolve network constraints.

Scottish generators will contract their output in the forward markets, but will be increasingly constrained off in the balancing mechanism as the penetration of wind generation increases. Indeed, as penetration of wind generation in Scotland increases, the total volumes (and revenue) that Scottish Generators trade in both markets (the PX and the BM) will decrease. The constrained line between England and Scotland is limiting export from Scotland, so additional wind is directly displacing Scottish generation.

English generators will also contract less in the forward markets as low marginal cost wind generation displaces higher cost incumbent generation. However, this is counteracted by increasing activity for English generators in the balancing mechanism, and an increasing volume of offers accepted. Since, in a constrained system, the export from the Scottish group of generators must always be the same, English generators will always be required to dispatch the same final volume, regardless of the level of wind penetration in Scotland. So overall output (and revenue) from English Generators remains the same.

Impact assessment analysis: Drivers of constraint costs

The theoretical result outlined above relies upon generators that are constrained off paying back their marginal cost of generation, and those which are dispatched to balance the system only charging up to their marginal cost. In the real system it is likely that generators constrained off

will attempt to retain some of their revenue gained in the energy markets, and those constrained on are likely to charge more for their dispatch in the balancing mechanism. This situation is obviously open to abuse of market power, further exploration and modeling of constraint costs on a simplified GB system is needed.

However, some broad conclusions can be explored in a qualitative manner using the drivers identified in the impact assessment matrix.

Location and power flows

Although this section has been focused on wind generation, the impact of DG on the transmission network is similar. Both wind generation and DG will contribute to transmission congestion (and costs) according to their location in relation to demand and their subsequent impact on power flows. Note that although distribution connected generation may contribute to balancing demand locally, the nature of the interconnected GB system is that local activity and changes in net flows between transmission and distribution will have an impact on the system as a whole, particularly with reference to the existing North-South power transfer. Generation connected (close to demand) in the distribution network has an impact on the net import/export position of a particular node, which in turn impacts on the use of the transmission system. Distributed plant generating in the South will effectively reduce local demand and have a beneficial effect on the North-South power flows. Conversely, generation connected at distribution level in the North and Scotland will reduce local demand in an area already dominated by generation, increasing export and possibly exacerbating system operation issues associated with North-South power transfer.

For the UK, this pattern of North-South, generation and demand is likely to continue into the near future, so locational considerations of wind generation and DG will be important in determining the full impact of non-conventional generation on transmission constraints and costs.

Pattern and time of output and Diversity of network users

The impact of non-conventional generation on transmission constraints is also moderated by the pattern and time of output. Transmission constraints are most likely during peak demand times, when all conventional generation is running close to full output. Non-conventional generation (in the "wrong" location) that runs during these times will contribute directly to an increase in constraints and costs. However, for most non-conventional generation output is not dictated by demand requirements but by less predictable elements such as the weather. So, even units in the "wrong" location in the North of the country may have a negligible impact on constraints if they

operate at non-peak times when there is ample network capacity to accommodate additional input.

Building on this concept, diversity in network users (i.e. conventional and non-conventional generation) that use the network at different times because of differing drivers for output will also mitigate the impact of non-conventional generation connecting to an already congested area. If the surrounding network users require access at peak times, then non-conventional generation may effectively be able to share the existing capacity and only occasionally contribute to network congestion on the few occasions when peak output happens to be coincident with peak demand. Correlation between peak demand conditions and peak wind generating conditions are very weak (Grubb, 1988, Oswald, 2006) and correlation between wind output and cold temperatures is also uncertain (Oswald, 2006). In all, although simultaneous peak output from conventional and wind generation is possible, it is a random occurrence and not linked by any strong statistical correlations.

Summary

This assessment highlights that although non-conventional generation will have the same headline impact as conventional generation on constraints, the magnitude of these impacts can be mitigated by a number of drivers. For both conventional and non-conventional generation the impact on constraints is driven initially by location of generation relative to demand. But for non-conventional generation, time of use of the network is of additional importance in determining actual impact on constraints. The operating patterns of many non-conventional generators are fundamentally different from their conventional counterparts; recognition of this in transmission access arrangements (particularly within a charging regime) is the key to reflecting an accurate picture of the short term costs imposed by these technologies.

3.3.3 Transmission investment: Capacity requirements for wind

The current network planning standards that guide network reinforcement requirements were developed on the basis that generation technology would be operating at maximum output during times of peak system operation (i.e. peak demand coincident with peak prices). Therefore, it has been reasonable to design and price transmission investments on the basis that the capacity provided should be sufficient to accommodate simultaneous peak output from all connected generators. Output from wind generation is variable, generally inflexible and thus cannot be optimised according to price signals. Output can be predicted to a certain degree, but forecasts for generation become increasingly accurate closer to real time. As highlighted in the previous section, these differences in operating characteristics and time of use of the system have a fundamental impact on the way in which wind generation uses the system and also how it drives investment in transmission.

Chapter 2 revealed the drivers for transmission network investment in the UK, namely reliability and economic efficiency. To date, the requirement to meet standards for reliability has driven transmission network design and reinforcements, and this has been sufficient to also meet the capacity requirements for economic efficiency (i.e. allowing demand customers to access the cheapest generation). However the penetration of wind generation is likely to change this balance. This section will examine how wind generation impacts transmission investment requirements according to these two methods for determining transmission capacity, and will explore how the balance between these two drivers for capacity investment is changing.

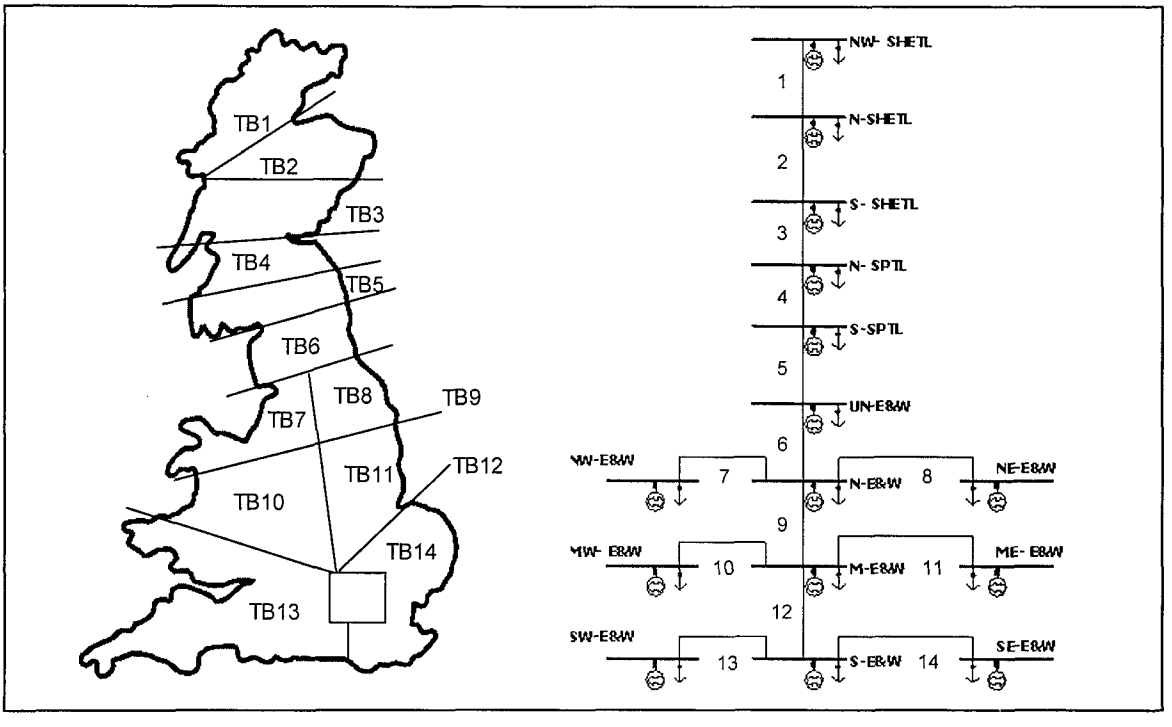


Figure 3-3: Simplified Great Britain (GB) transmission system

The following sections present the findings on the impact of wind generation on the transmission network from the report by (Strbac et al., 2007). The methodologies for transmission investment for reliability and economic efficiency are illustrated on a two-busbar example system (reliability only) and on a simplified GB transmission model, see Figure 3-3. Using the GB transmission model, the methodologies propose transmission capacities for each of the 14 major boundaries in the model when 10GW of wind is added in Scotland and 3GW in England (using a non-diversified wind profile)[21]. This study compares the outcomes of both approaches to the results for network capacity delivered by the existing GBSQSS approach – all these findings are presented and explored below:

Transmission network capacity for reliability

[21] The method also assumes that no conventional plant is retired (worst case scenario) and that the marginal cost of generation in Scotland is lower than that in England (which will tend to drive more transmission capacity).

Wind power characteristics & the contribution of wind to system reliability

The contribution of any generation technology to system reliability depends on its capacity credit, i.e. how much incumbent generation capacity it can displace without adversely affecting the overall reliability of the system. The greater the capacity credit, the more a technology can be relied on to secure load during peak conditions. If a generator is crucial for securing load then network capacity must be provided to ensure that it is not unduly restricted from doing so.

The ability of wind generation (and many intermittent/variable generating technologies) to displace incumbent generation capacity is somewhat limited. Table 3-2 below illustrates this point, taken from the UKERC review of the costs and impacts of intermittent generation; this extract of a representative sample of the studies explored in the UKERC report reveals that all recent work has shown that wind has limited capacity credit.

Study	Wind penetration	Capacity credit range
(MottMacDonald, 2003) Carbon Trust and DTI intermittency survey & roadmap	10 - 20%	27.5 - 20%
(Dale et al., 2004) Total cost estimate for large scale wind scenarios (Energy Policy)	20%	19.1%
(Ilex and Strbac, 2002) Quantifying the system costs of additional renewables in 2020 (SCAR), for the DTI	17 - 27%	22.9 - 18.4%
(Grubb, 1991) The integration of renewable electricity sources (Energy Policy)	5 - 38%	35 - 19.3%
(RAoE, 2003) Royal Academy of Engineering response to the House of Lords Science and Technology committee inquiry into the practicalities of developing renewable energy	11.6 - 31.3%	26.7 - 16%
(Sinden, 2005) Wind power and the UK resource, Oxford Environmental Change Institute for the DTI	10%	23.1%
(KEMA-XENERGY, 2004) Intermittent wind generation: summary of report of impacts on grid system operations	4.8%	25.9 - 0%

Table 3-2: Wind Capacity credit, extract from (UKERC, 2006)

The findings from these studies suggest that wind can, at best, have a capacity credit of 35% for low penetrations of the technology and as the penetration increases the associated capacity credit decreases. Some of the quoted studies (e.g. Sinden, 2005) consider the capacity value of wind on the basis of an even dispersal of the technology across the country. The picture becomes more complex as we consider the impact of uneven geographic dispersal and clustering in a single location. For wind farms spread across a very wide geographical area the diversity effects will be significant ("diverse" wind), there will be less correlation between outputs from generators in the portfolio under consideration, and less chance of low (or zero output) (Ilex, 2001). While wind farms in close proximity will have a closer correlation in

output profiles and will be characterized by low-diversity profiles ("non-diverse" wind)[22]. This is illustrated in Figure 3-4 which shows the frequency distribution of the half-hourly wind power output for diversified and non-diversified wind generation profiles.

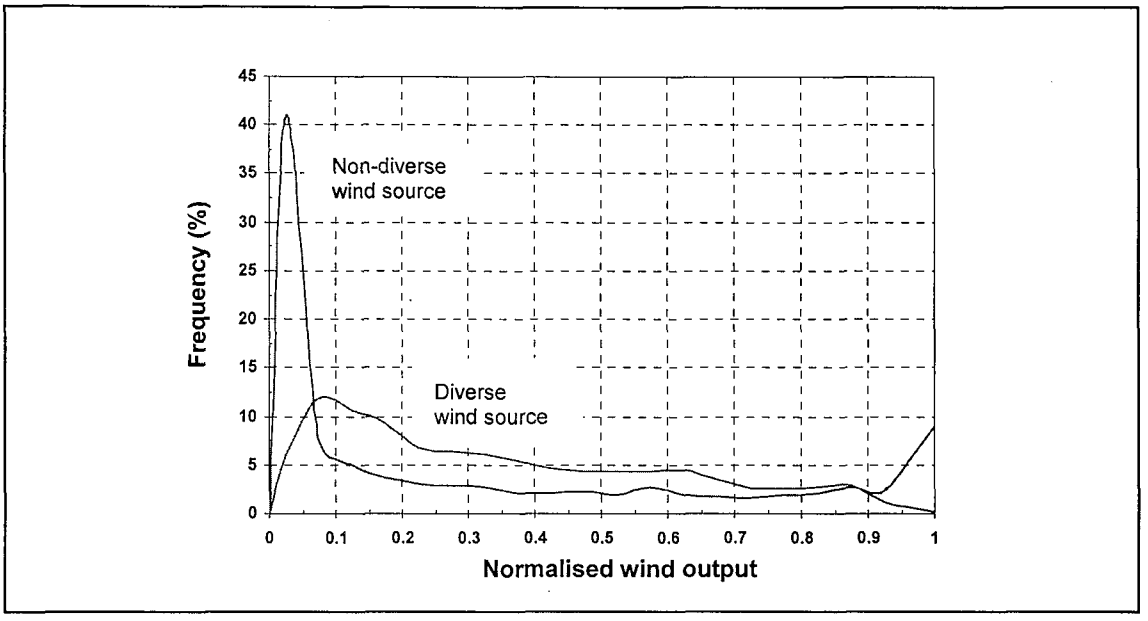


Figure 3-4: Normalized wind output for diverse and non-diverse wind sources (Ilex and Strbac, 2002)

The figure illustrates the smoother distribution of the diverse wind source, illustrating that diverse wind output can provide a more consistent resource , with an improved load factor to the non-diverse portfolio (Holttinen, 2004). This is echoed in the estimation of capacity values for diverse and non-diverse sources. Using the normalised outputs in Figure 3-4, Figure 3-5 represents the capacity credit for various levels of installed wind capacity and illustrates the two different diversity characteristics.

[22] The majority of wind developments pending connection are in Scotland. This would place the UK profile somewhere in between the diversified and non-diversified profiles, closer to the non-diversified end of the scale.

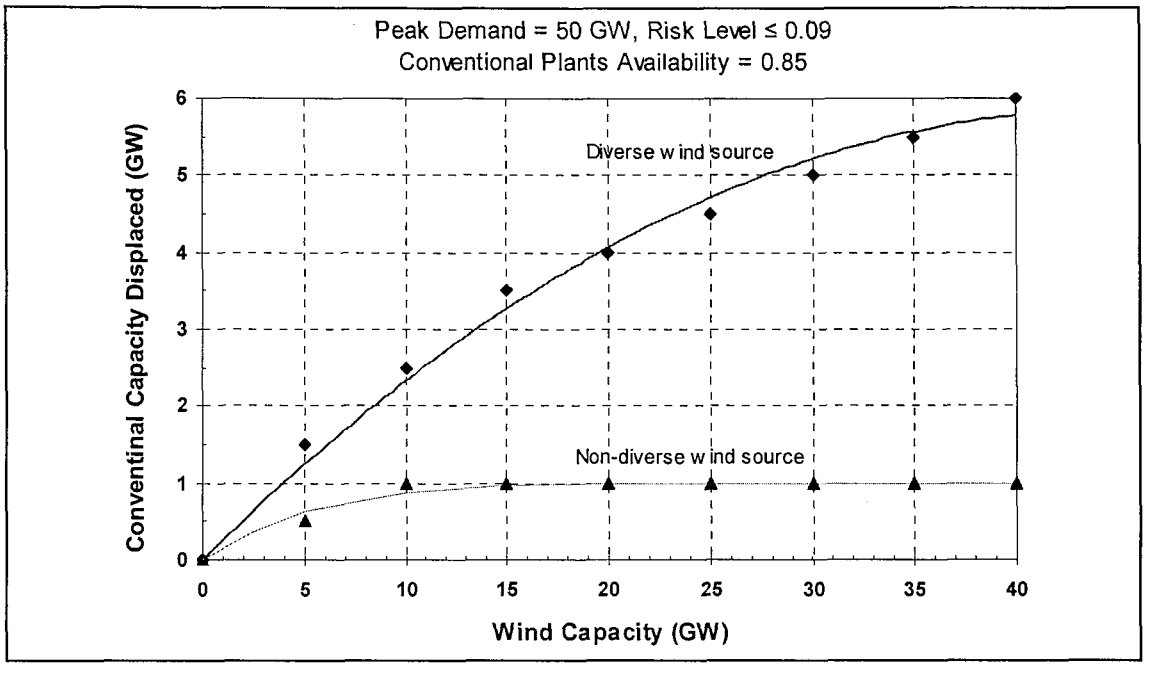


Figure 3-5: Capacity of conventional plant that can be displaced by wind generation (Strbac et al., 2007).

Figure 3-5 shows that at low levels of wind penetration the capacity credit of wind is relatively significant. However, as the capacity of wind generation increases the curve heads towards saturation resulting in a decrease of the marginal contribution: 40 GW of wind capacity displaces only about 6 GW of conventional generation. Clearly, in order to maintain the same level of reliability, a significant capacity of conventional plant will still be required. In the case of wind farms characterized by a non-diversified profile, the capacity credit of wind reduces further. The figure shows that the capacity displacement tails off after the 10 GW wind penetration level. The reason for this is that the probability of wind output at low levels is much higher than in the case of diversified profile as shown in Figure 3-4. The correlation effect seen for the output of diversified resources is lost in non-diversified output.

This illustrates that wind (particularly from non-diverse sources) makes an increasingly limited contribution to maintaining the generation capacity margin. The knock-on impact of this is that load secured by connection of wind generation will not be equal to the capacity of wind generation added into the system. Only a (small) proportion of capacity can be relied upon as a resource to secure load during peak conditions when making calculations regarding system reliability. Because wind (and other technologies with a low capacity value) can only make a small contribution to system reliability; this generation technology is unlikely to require significant network capacity in systems built for reliability. This is illustrated in the following sub-section.

Transmission capacity requirements for wind in systems designed for reliability - example

As detailed in the study from the CDGSEE (Strbac et al., 2007), a simple two-busbar system can be used to illustrate the impact of the low capacity credit of wind generation on driving capacity reinforcements in systems designed for reliability (Figure 3-6). The system under analysis is characterized by 5GW of peak demand in area A and 45GW of peak demand in area B, and a total installed generation capacity equivalent to 50GW[23]. Area A is also characterized by the presence of wind power with an increasing penetration level varying from 0 to 20GW.

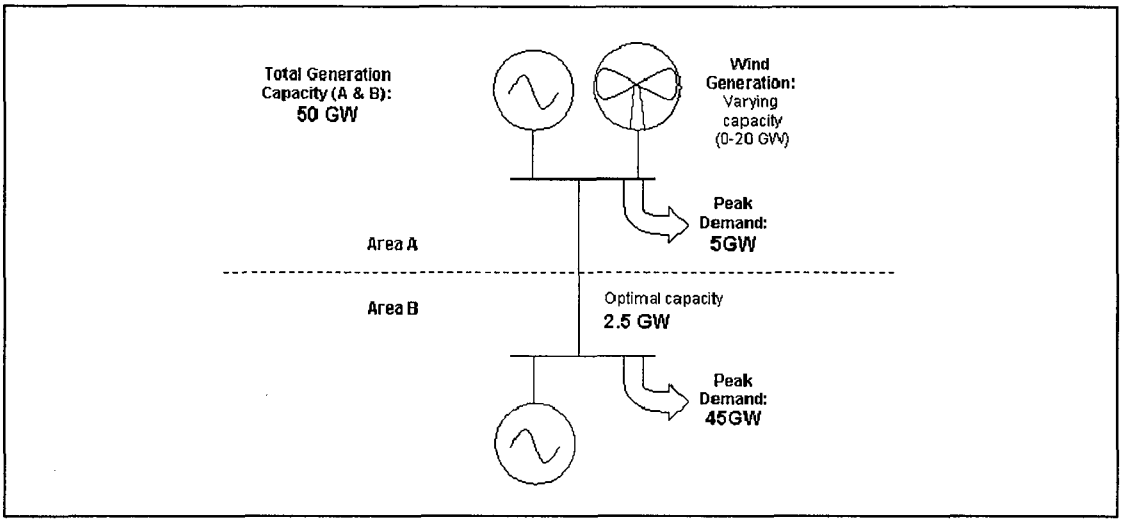


Figure 3-6: 2 bus-bar example illustrating the methodology for determining transmission capacity requirements driven by reliability in systems with varying penetration wind

Figure 3-7 and Figure 3-8 present the transmission capacity required to connect the two areas for different levels of conventional generation and wind generation capacities in area A. Figure 3-7 presents the case for a diverse wind profile, Figure 3-8 for a non-diverse profile. In all cases, the amount of transmission capacity maintains the LOLP based on the 5% additional risk imposed by finite transmission capacity by retiring the appropriate amount of conventional generation from the system.

[23] Accounting for the reduced capacity credit of wind generation as detailed earlier.

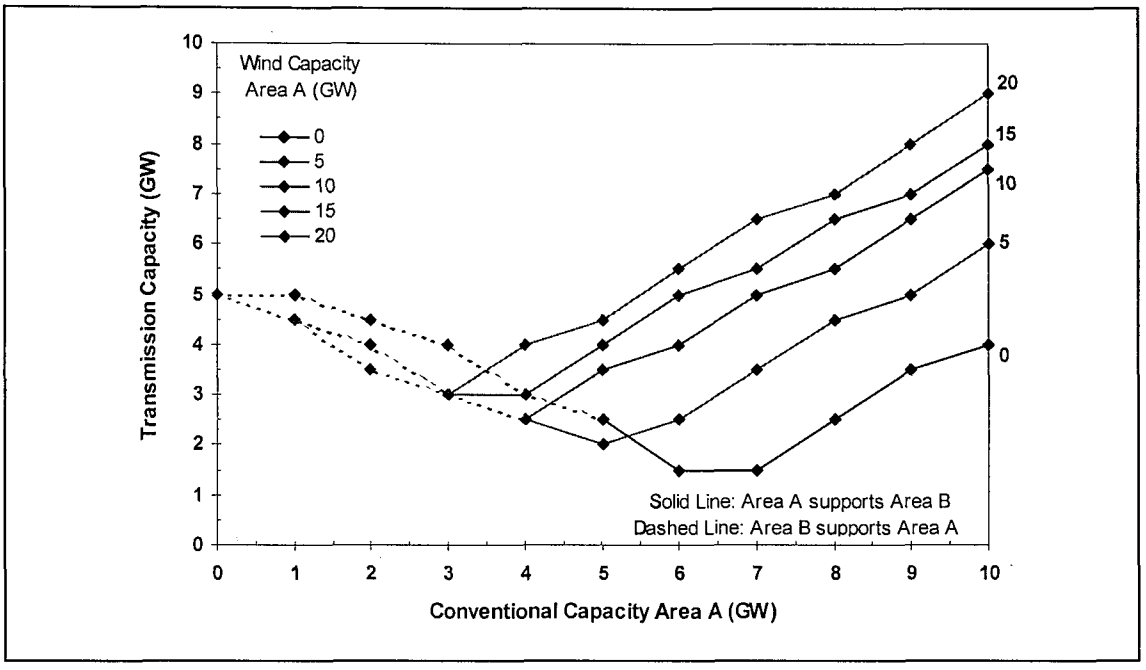


Figure 3-7: Transmission capacity requirements for the system with diverse wind generation resources

Figure 3-7 and Figure 3-8 show that when area A is an importing area, the presence of wind generation in the system leads to a relatively modest reduction of transmission capacity requirements compared to the capacity required by the equivalent system without wind. The transmission capacity remains practically at the same level for increased levels of installed wind capacity. Such behaviour suggests that wind has a modest transmission capacity credit to provide reliability in the importing area. It is important to note that an area is considered to be an import area if additional generation in that area reduces transmission capacity requirements although the total installed generation capacity may already exceed the peak load in that area.

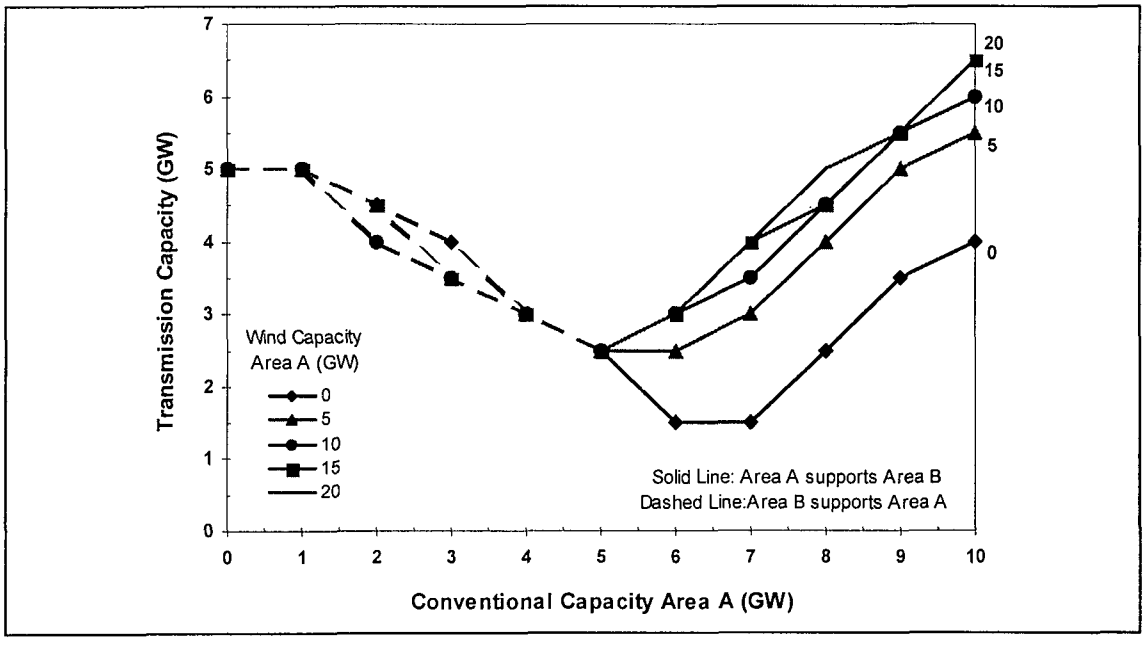


Figure 3-8: Transmission capacity requirements for the system with non-diverse wind generation resources

When area A is an exporting area, although the presence of wind generation increases the need for transmission reinforcement, this increase is relatively small compared with the wind capacity installed. As expected, we can also observe that diverse wind generation would require more transmission capacity than non-diverse wind. For example, in the case of 8 GW of conventional generation is present in the system A, the transmission capacity will increase from 2.5 GW for no wind to 5.5 GW for 10 GW of diverse wind installed. In the case of 10GW of non-diverse wind, the required transmission capacity will be 4.5GW. In this case, transmission capacity is built to allow conventional and wind generation in area A to contribute to the reliability of supply in area B. However, the increase in transmission capacity required for this purpose becomes smaller with increased levels of installed wind capacity. This indicates that the transmission capacity credit of wind generation (the percentage of the conventional capacity that wind can displace) decreases when wind penetration level increases.

Transmission capacity requirements for wind in systems designed for reliability – GB model

This approach to determining transmission capacity requirements to maintain reliability was also carried out on the simplified 15 bus-bar GB system as detailed in Figure 3-3.

Boundary	From	To	Transmission Boundary Capacity (MW)	
			Reliability	*GBSQSS*
1	*NW-SHETL*	*N-SHETL*	**2100**	**2561**
2	*N-SHETL*	*S-SHETL*	**3500**	**4439**
3	*S-SHETL*	*N-SPTL*	**3300**	**4904**
4	*N-SPTL*	*S-SPTL*	**4100**	**5438**
5	*S-SPTL*	*UN-E&W*	**4300**	**7667**
6	*UN-E&W*	*N-E&W*	4700	7514
7	*NW-E&W*	*N-E&W*	2400	2424
8	*NE-E&W*	*N-E&W*	5600	4895
9	*N-E&W*	*M-E&W*	8700	10674
10	*MW-E&W*	*M-E&W*	6800	6848
11	*ME-E&W*	*M-E&W*	5400	4869
12	*M-E&W*	*S-E&W*	8100	9206
13	*SW-E&W*	*S-E&W*	3400	4360
14	*SE-E&W*	*S-E&W*	5100	4766

Table 3-3: Comparison of transmission capacities associated with key system boundaries derived using the approaches for reliability and the current GBSQSS (Strbac et al., 2007)

The results are presented in Table 3-3, alongside the results using the existing GBSQSS method (that treats wind generation as though it had the similar characteristics as conventional generation, and applies a scaling factor to wind equivalent to a capacity credit of around 60%). Observation of these results shows that the methodology for designing networks for reliability

delivers less capacity at all of the boundaries in Scotland (highlighted in bold) where the bulk of the wind generation has been placed. This reflects the earlier finding that as wind has limited capacity credit, it is not necessary to build transmission capacity to accommodate it. The scaling factor for wind currently applied by the GBSQSS equates to an equivalent capacity credit of around 60%. The result of this allocation is an overestimation of capacity required in exporting areas, but underestimation of capacity in importing areas. In this result we can see that the current GBSQSS would tend to overestimate the contribution that wind is making to reliability, and build more transmission than is necessary.

Drivers of capacity for non-conventional generation in systems built for reliability

Location

The import/export nature of the local network will impact on the transmission requirements of wind and non-conventional generators. In exporting areas the addition of low capacity credit non-conventional generation often drives less transmission capacity than conventional generation. However, in importing areas, addition of such non-conventional generation may not displace significant amounts of network interconnection capacity. Its output cannot be guaranteed to cover the local load requirement, so interconnection capacity is still required to allow the load to be secured from other areas. In some instances, for example if local conventional generation is retired from areas with wind generation (or other low capacity-value technologies), additional investment in interconnection capacity may actually be required to maintain system reliability.

Capacity credit

As described in the earlier sub-section, the capacity credit of a generation technology is a major contributor to the network capacity that it can drive. Those with low capacity credit cannot be relied on to secure a significant amount of load at peak time and will correspondingly drive less transmission capacity to support this limited activity.

If the same analysis is carried out as shown in Figure 3-7 and Figure 3-8, but presuming that the non-conventional generation has the same capacity credit as conventional generation, the capacity requirements are very different. Firstly the calculation would allocate a far higher firm output to the installed non-conventional generation, making the area A an exporting area. Secondly, it would recommend over investment in capacity to support that output in meeting demand in area B. The characteristic V curve in the figure would be lost; and the system would be under-invested when there are low levels of conventional generation in area A and increasingly over invested as conventional generation increases and area A exports.

Diversity of network users (generation)

Diversity in generation changes the capacity required for reliability driven investment through altering the output profile of the generators under consideration. This in turn changes the capacity credit of the technology. For example in the case of wind; a diverse wind resource will have a less intermittent output profile. As a consequence it will have an increased capacity credit, and will drive more capacity that a non-diversified wind resource. Diversity in resources can also come from considering a group of different generation technologies (and demand). Positive benefits of diversity would be seen if there was low correlation in output between technologies (i.e. the intermittent generation in one technology falls at a time when another is not generating). Diversity of network users will be of particular relevance for distributed generation gaining visibility at transmission level and exposure to the relevant transmission access arrangements. The impact of DG at transmission level is represented by the flow at the transmission-distribution boundary. This flow will be a product of the generation and demand in the network below the boundary. The level of diversity in these users will be a key feature in determining the ultimate impact of DG on transmission capacity requirements.

Transmission network capacity for economic efficiency

Cost benefit analysis to determine economically optimal investment

Optimisation of network capacity according to the most economically efficient solution will allow demand customers to take advantage of low marginal cost generators, such as wind. By conducting a cost-benefit analysis, decisions taken to reinforce transmission can be justified if the savings in the marginal reduction in out of merit generation cost (marginal cost of constraints) caused by penetration of new wind generation are greater than the marginal transmission network investment cost (see Figure 2-6).

The previously cited study from the CDG&SEE developed an investment optimisation methodology (based on a DC-load flow optimisation formula and using a simplified GB transmission model, Figure 3-3) that, through simulation and optimisation of the system operation across an annual time horizon, balances the annual generation costs and amortised investment costs in order to analyse the need for transmission system reinforcements. Under this methodology, the cost of transmission infrastructure and the cost of constraints will be the key drivers for decisions associated with network reinforcement[24].

[24] Although it is in principle appropriate that a cost-benefit analysis is applied for determining network capacity and investment, this approach also relies on a range of assumptions that may be contentious. This includes future generation technology distributions, fuel costs, projection of future constraint costs and their variations in time and space, network reinforcement cost (which may also vary significantly). The accuracy of the results could depend significantly on the accuracy of the modelling process. However, not only the values that would be used in such evolutions debatable, but so too is the basis on which these values should be derived. In addition, there are questions as to whether and how the short term imbalance prices should be used as signals for making decisions on long-term transmission investment, given their volatility. There are also significant uncertainties associated with the conversion of

To illustrate the outcome of a Cost Benefit Analysis (CBA) for transmission requirements in the case of connection of wind in Scotland, 10GW of wind was connected in locations in Scotland in the GB model outlined above. The analysis assumes that no conventional plant will be decommissioned in Scotland (worst case scenario) and that constraint costs are cost reflective. The total installed capacity of generation (conventional plus wind) in Scotland is fixed at 19.5GW, and local load is set at 6.5GW.

Transmission capacity requirements for wind in systems designed for economic efficiency

The results for economically optimal transmission capacity at each of the 14 boundaries are presented in Table 3-4 alongside the results for a reliability optimised design and the current GBSQSS approach.

Boundary	From	To	Transmission Boundary Capacity (MW)	
			Economics	*GBSQSS*
1	*NW-SHETL*	*N-SHETL*	2437	2561
2	*N-SHETL*	*S-SHETL*	3571	4439
3	*S-SHETL*	*N-SPTL*	4110	4904
4	*N-SPTL*	*S-SPTL*	3564	5438
5	*S-SPTL*	*UN-E&W*	5357	7667
6	*UN-E&W*	*N-E&W*	4935	7514
7	*NW-E&W*	*N-E&W*	1942	2424
8	*NE-E&W*	*N-E&W*	2218	4895
9	*N-E&W*	*M-E&W*	7870	10674
10	*MW-E&W*	*M-E&W*	4798	6848
11	*ME-E&W*	*M-E&W*	4459	4869
12	*M-E&W*	*S-E&W*	8434	9206
13	*SW-E&W*	*S-E&W*	2781	4360
14	*SE-E&W*	*S-E&W*	1438	4766

Table 3-4: Comparison of transmission capacities associated with key system boundaries derived using the approaches for economic efficiency and the current GBSQSS (Strbac et al., 2007)

When building transmission network for economic efficiency, the key impact of non-conventional generation is that it is no longer optimal to build a network to support the simultaneous output from all generators; instead generators can share network capacity. This is illustrated in the capacity requirements indicated for the Cheviot Boundary (boundary number 5 between England and Scotland). To accommodate peak output would indicate the construction of more than 10GW of capacity in this location (total generation capacity in Scotland less local demand). However, from Table 3-4 it can be observed that economically optimal network

the applications for connecting wind power into actual projects due to difficulties of obtaining planning consents and other reasons.

capacity across boundary 5 should be set at 5.4GW. This result provides clear evidence that it is not economically efficient to invest in transmission to accommodate simultaneous peak outputs from both wind and conventional generation, and it demonstrates that transmission capacity should be shared between conventional and wind generation. On windy days the capacity of transmission corridor between Scotland (S-SPTL) and England (UN-E&W) is primarily used to transport wind power, while on non-windy days, this capacity would be used to export energy from conventional plant.

The cost-benefit approach illustrates that economically efficient transmission investment is made when the opportunities for sharing of transmission between different generating resources are recognised. The analysis has shown that the contribution of wind generation to use of this shared capacity is less than conventional generation, therefore wind (or other non-conventional generators with low capacity credit) should also be charged less. Distinguishing between generation-types and location to reflect these differences in operation characteristics and output is essential if optimal decisions are to be made in transmission investment and if cost-reflective pricing regimes are to be devised for accurate reflection of generation costs imposed on the system.

Drivers of capacity requirements for non-conventional generation

Pattern and time of output

Pattern and timing of output is crucial in dictating the contribution to network reinforcement. Wind generation and other non-conventional generating technologies are not load-following. Rather, their output is dictated by the weather or other variable factors. In this instance, output from these generators will not be coincident with the system peak by design, allowing the sharing of capacity. The extent to which this can occur will depend on the level of correlation between the outputs of each technology.

Diversity of other network users and pattern and time of use of the system

The diversity of surrounding users will impact on the opportunities for sharing of network capacity. In areas with conventional and non-conventional generation or those that are characterised by generation units that have non-correlated use of the system, sharing of capacity will be possible. However, in areas with homogenous generation technologies the opportunity for sharing will be limited. In this instance network capacity should be provided to meet the maximum output of the connected units, such as the proposed Beauly-Denny transmission connection (NGET, 2007a). Here, wind is the only source of exporting power, so it becomes economically viable to install transmission to accommodate the full peak output of wind generation and prevent curtailment of a zero-marginal cost generator.

3.3.4 Summary and conclusions

As highlighted in Chapter 2 (section 2.4.1), the contributions of the network to compromising overall system reliability through preventing generation from accessing demand under peak conditions are limited. The presence of an optimally constrained transmission network only increases the Loss of Load Probability (LOLP) from 9 to 9.5% (i.e. increasing the chance of system failure from 9 to 9.5 times in 100 years). This means that historically, generation has had almost full access to load; the network has been built on the basis of reliability which has created a transmission system with a degree of network redundancy that does not compromise the economic efficiency driver for transmission (i.e. more than adequate capacity is built to satisfy the transmission requirements that allow load to access cheap generation)..

All this has kept operational network constraints to a minimum in the conventional system. However, with the addition of non-conventional generation to the network, particularly wind generation, this picture is changing. As the impact assessment has identified, wind power can displace energy produced by conventional plant (i.e. reduce the fuel burnt), but its ability to displace conventional plant is limited. As the capacity credit of wind power and other non-convention generators is limited, network reinforcement driven by non-conventional generation will be limited in systems designed for reliability. Wind generation is essentially a fuel saver, rather than a contributor to generation capacity, so building transmission to support it on this basis is not optimal.

Wind is, however, low marginal cost and thus too cheap to constrain off on a regular basis. So the new network to support the sustainable power system needs to make sure that sure that wind is not constrained unnecessarily. An assessment should be made to determine what level of additional transmission is required to facilitate economically efficient sharing of capacity. Then expensive and fossil fuelled generation should be constrained off the system when the wind is blowing coincident with system peaks.

This signals a change in the decision making process for investment in transmission capacity. Although reliability is still a driver, optimal networks built for non-conventional generation are likely to be constructed with economic efficiency as a dominant factor dictating network investment decisions. The requirement for high levels of network redundancy across the network to ensure reliability will be reduced (because some connected generators will not be making a contribution to this aspect of system planning), and in some areas where capacity is driven by economic efficiency the occurrence and relevance of constraints is likely to increase.

3.4 Distribution impact assessment

3.4.1 Introduction

As discussed in Chapter 2, modern distribution systems were designed to accept bulk power from the transmission network and to distribute it to customers. The flow of power was always from the higher to the lower voltage levels. However, with significant penetration of distributed generation the power flows may become reversed. As this situation develops the distribution network is no longer a passive circuit supplying loads but an active system with power flows and voltages determined by generation as well as loads.

As per the impact assessment methodology, this section reviews the major impacts of DG on the distribution network operation and investment, both positive and negative. In addition it illustrates how these impacts can be mitigated and moderated with the use of active management and the other drivers detailed in the introduction. It also discusses the implications and materiality of these impacts in the context of the present distribution network and the current and expected penetration of distributed generation.

3.4.2 Distribution network operation

The operational performance indicators in the distribution network are the levels and duration of network outage (to which the customer quality of supply indicators, CI and CMLs, are linked) and the magnitude of losses. Relevant DG network impacts are those with a negative or positive impact on either of these operational characteristics. The main impacts caused by DG in the operational timescale are: increased fault levels, voltage rise effect and reduction in losses from connection of micro-generation. Each of these impacts is reviewed in turn, also highlighting the drivers that can moderate or mitigate their effect.

Voltage rise effect

Every DNO has an obligation to supply its customers at a voltage within specified limits. This requirement often determines the design and expense of the distribution circuits and so, over the years, techniques have been developed to make the maximum use of distribution circuits to supply customers within the required voltages. During minimum load the voltage received by all customers is just below the maximum allowed; if a DG unit is now connected to the end of such a circuit then the flows in the circuit will change and hence the voltage profiles will also be affected. The most severe case is likely to be when the customer load on the network is at a minimum and the output of the distributed generator must flow back to the source.

Current operating policy based on passive operation of distribution network limits the capacity of generation connected based on the extreme condition of minimum load, maximum

generation. In order to minimise the overall voltage rise effect, network operators prefer to connect DG at higher voltages where their impact onto voltage levels is minimal. However, the commercial viability of distributed generation projects is sensitive to connection costs. These costs increase considerably with the voltage level at which the distributed generation is connected; generally the higher the voltage or more sparse the network, the higher the cost. The developers of distributed generation therefore prefer to connect at lower voltages.

Drivers of voltage rise

Location, density of installation & diversity of surrounding generation and load

In rural areas, or sparse parts of the distribution network, locations at the end of long feeders with limited local demand are particularly susceptible to these voltage rise effects. Clearly, the surrounding generation/demand environment is also important, and the impact can be mitigated to some extent through demand participation and demand response to increase loads at critical times on the network.

Network management philosophy

The present passive network operation philosophy is known to considerably limit the amount of distributed generation that can be connected in areas susceptible to voltage rise; however, an active management approach will allow considerably greater penetration of distributed generation.

(Shafiu et al., 2004) illustrate the impact that active management techniques can have on DG induced voltage rise effect in rural areas. Coordinated voltage control with on load tap changers (OLTC) enables connection of increased capacity of DG by actively changing the OLTC setting and maintaining the voltages of a distribution network within defined limits. Remote measurements from key network points are transmitted to the relevant substation and used to control the set-point of the OLTC automatic regulator. This approach does require additional ICT infrastructure to be installed within the network; however, the active management approach mitigates significant levels of network reinforcement, such that avoided infrastructure costs can outweigh ICT investments in many instances.

Further analysis in (Grenard et al., 2005) quantifies the impact of active management to mitigate voltage rise for the UK distribution system caused by integration of various levels of CHP. The work estimates total cost of implementing active management techniques to be between £40 million and 160 million[25]. The incremental cost of reinforcement under passive and active

[25] The highest cost implementation appears in the low-density penetration scenario (because more widespread upgrades are required to accommodate the active management techniques across a wide area).

network management scenarios, for low and high density penetration of DG, is presented in Table 3-5. The study concludes that where the connection of DG is imposing additional reinforcement costs to the system, there will be a cost saving from implementing an active management approach. Furthermore, in every instance this cost saving outweighs the initial implementation costs.

Penetration of DG	Density of Installation and Active Management Control Scheme			
	Low P	*Low A*	*High P*	*High A*
2.5GW	0	0	0	0
5GW	0	0	238	84
7.5GW	100	0	359	253
10GW	243	0	560	376

Table 3-5: Total incremental cost of upgrading feeders and substations in rural systems (in £million) for passive (P) and active (A) management (Grenard et al., 2005)

However, it is noteworthy that at the lower penetrations of DG under the low-density scenario, the initial impact of connection is minimal on the network. This indicates that the existing network is already reasonably resilient and capable of absorbing an amount of generation before any additional cost is incurred.

Increased fault levels

Accurate detection, location and isolation of faults are the key components to reliable operation of an electricity network. When a fault occurs, a fault current is generated on the network. The fault current must be large enough to be easily and quickly distinguished from normal currents and be localised enough to indicate the position of the fault so that it can be repaired quickly. However, this must be carefully judged such that the current remains within the operating limits of the circuit breaker that must interrupt the current. Adding DG tends to increase the current and confuse these locational signals, and tends to increase the number of faults recorded. There is therefore a need to look at ways of limiting fault current to the safe maximum. This usually involves the upgrading of expensive switchgear, and could add significantly to the cost of connection of DG were this cost of upgrading to be passed through in its entirety.

Drivers of fault levels

Network management philosophy

The work undertaken by (Wu et al., 2003) outlines an active management technique for management of fault levels in urban areas, for networks with high penetration of DG. The management technique itself is a simple approach of splitting substation bus-bars. Fault level

management using this technique would open the 11kV bus section circuit breaker. By splitting the network in this way, the impedance between the 33kV and 11kV systems doubles, reducing the fault current coming from the upper voltage levels. Alternative methods for active management of faults include application of fault current limiters or reconfiguring bus-bar arrangements to reduce the fault level (Lopes et al., 2007).

Further analysis on the impact of active management on fault levels was undertaken in the previously cited study by (Grenard et al., 2005). Table 3-6 highlights the headline figures quantifying the impact of the network splitting activity on reductions of DG fault associated costs. The table presents the network reinforcement costs for the passive (P) and active (A) management philosophies under low and high density penetration scenarios. The figures presented in brackets in the active management columns represent the costs of implementation for the active management scheme.

Penetration of DG	**Density of Installation and Active Management Control Scheme**			
	Low Density, Passive Mgmt.	*Low Density, Active Mgmt. (cost of AM £million)*	*High Density, Passive Mgmt.*	*High Density, Active Mgmt. (cost of AM £million)*
2.5GW	796	0 (320)	398	0 (80)
5GW	796	0 (320)	398	0 (80)
7.5GW	796	0 (80)	415	415 (80)
10GW	796	0 (80)	1012	1012 (80)

Table 3-6: Total reinforcement costs of upgrading switchgear in urban areas (in £million) for passive (P) and active (A) management, with 0% headroom (Grenard et al., 2005)

The analysis shows that there are some considerable benefits of implementing active management schemes, particularly at lower penetrations of DG, although as penetration increases in high density situations the benefit can be lost entirely.

Reduction of losses

Energy losses from the network occur in the form of heat in transmission and distribution circuits. In the UK, annual losses from the distribution system account for around 7% of the electricity transported (Ofgem, 2003a). The magnitude of losses is influenced by a number of parameters, namely; electrical resistance of circuits, proximity of generation and load, temperature, network configuration, voltage level of transmission/distribution, voltage transformations, magnitude and diversity of the load and power factor. DG can influence losses through altering these parameters.

Drivers of reduction of losses

Time of output

Losses are at their peak during peak loading of the network. In the UK, peak loads occur during winter evenings around 5-6pm[26], so generation technologies that output during this period will contribute directly to reduction in losses. See Figure 3-9 for an illustration of the correlation between distribution network losses and daily load in both rural and urban locations. Because of the strong correlation between peak load and losses, reduction of load during critical periods can have a significant impact on loss reduction.

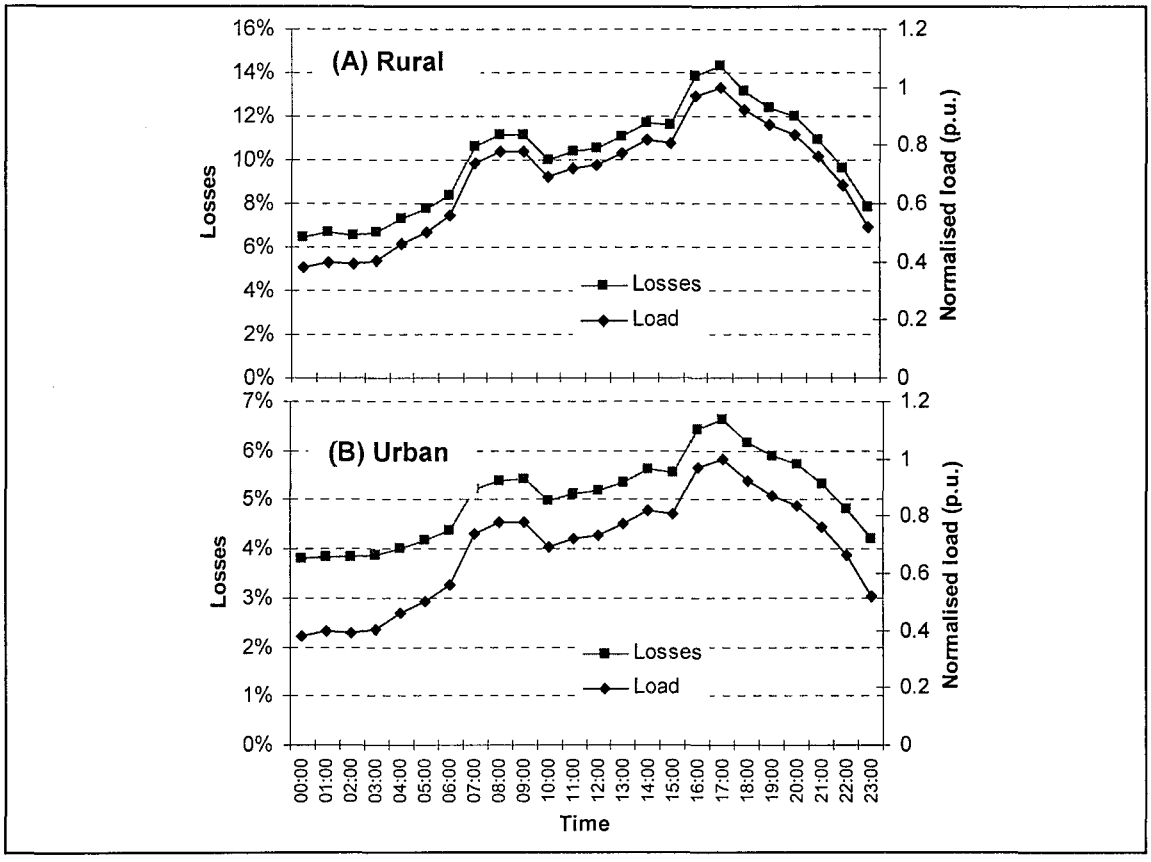


Figure 3-9: Correlation between losses and system load for (a) rural and (b) urban areas (Cao et al., 2006)

These contributions to loss reductions are entirely location specific, dependent on technology (size, type etc.), operating strategy, density of technology penetration, network topology, proximity to load, etc. The same generating technology in different locations can have opposite effects on network losses.

For example, CHP technology, the heat generated by domestic-scale μCHP is used for space heating inside the host premises. Therefore the electrical energy output of μCHP is most often driven by the heat requirements of consumers. Figure 3-10 illustrates the normalised generation

[26] See Figure 2-3 on page 39**Error! Bookmark not defined.** for the Summer and Winter daily demand profiles.

profile of μCHP. The study by (Cao et al., 2006) assumes the output of μCHP is nil during the summer, but the winter profile, as illustrated below, shows good shape correlation with the load/loss correlation profile (Figure 3-9) with the two characteristic output peaks in the morning and early evening driven by domestic heating demands.

Losses are a quadratic function of load; they are at their highest when networks are most heavily loaded. The strong correlation between μCHP output and peak loading means that μCHP can make a significant contribution to loss reduction by helping to meet load locally and reduce pressure on the network.

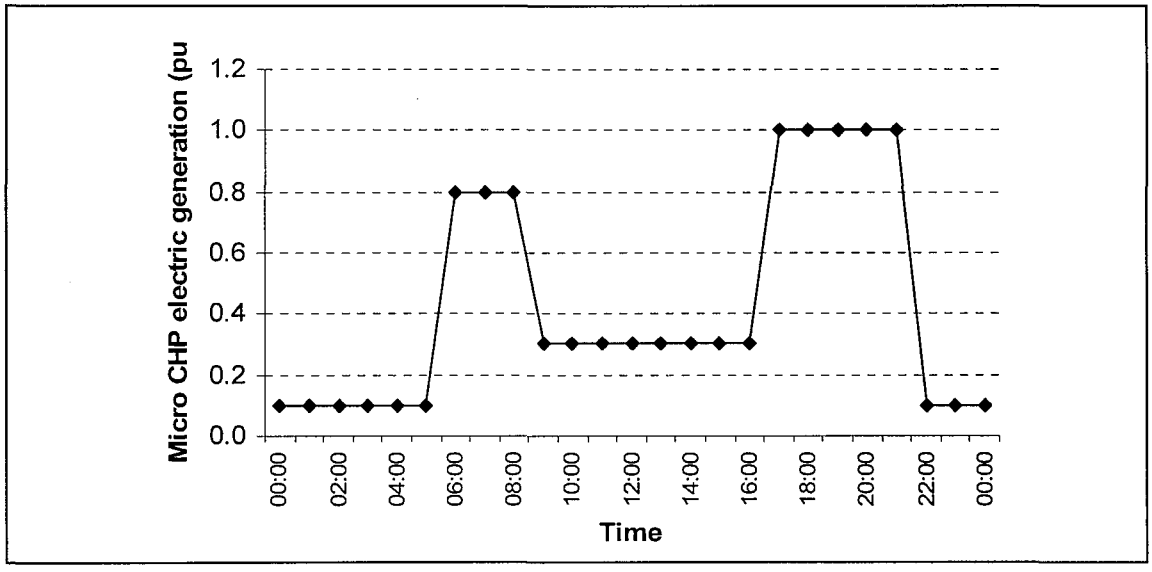


Figure 3-10: Normalised μCHP output during winter (Cao et al., 2006)

In contrast, photovoltaic (PV) generation makes a far smaller contribution. Much of the interest in PV in the UK is focused on incorporating the photovoltaic modules into buildings and houses. Thus, these small PV installations are connected directly into customers' circuits and so interface with the low-voltage distribution network. Figure 3-11 describes the normalised energy profile used in this study based on (Jenkins, 1995) to model the output of PV. PV output corresponds to the direct conversion of sunlight to electricity, which as the figure demonstrates corresponds to the height of summer over midday. During (typical UK) peak demand (winter evening around 6pm) PV output will be nil, and this technology will make zero contribution to reduction in losses.

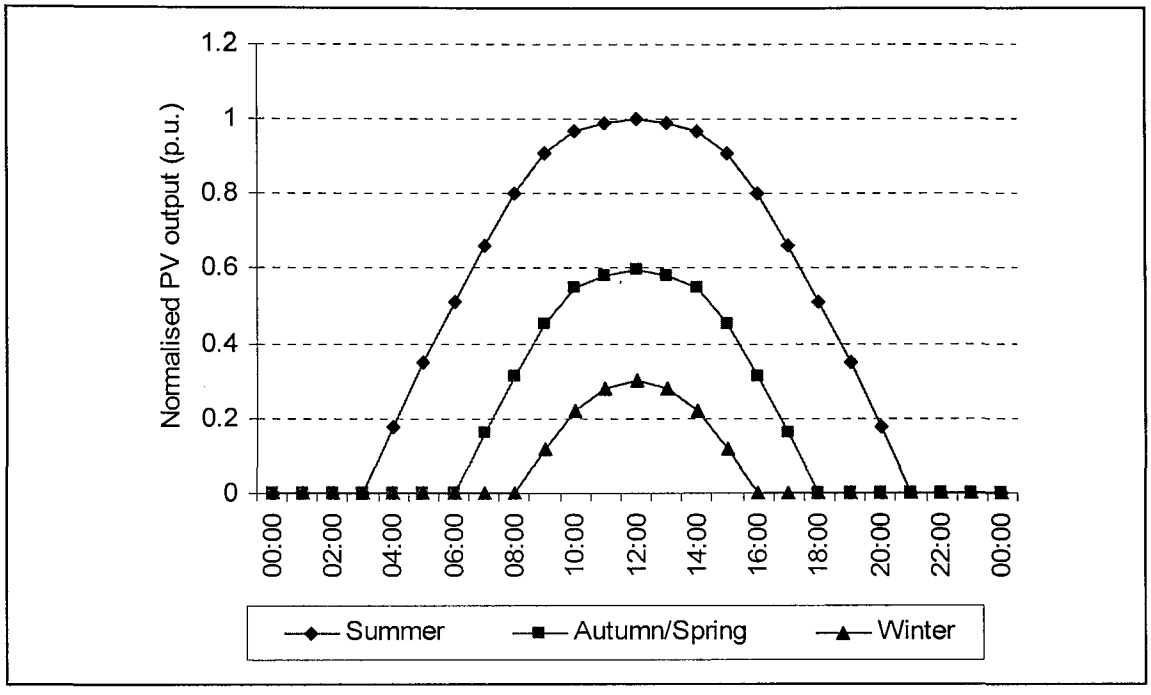


Figure 3-11: Normalised PV output profiles (Jenkins, 1995)

However, this can vary in some specific areas where the peak demand is not defined by winter conditions. As typified in some Southern European Countries, the summer peak is becoming increasingly prevalent. Driven by the need for cooling services during hot summer days, this peak demand is far better correlated to the PV output profile. In the UK, peak summer demand has been a network characteristic in some isolated cases (e.g. Central London) where air-conditioning load is out-stripping winter heat demands.

Location in the network

Through its location in the distribution network, appropriately sited DG reduces the transport distance to loads and can potentially make a significant contribution to reduction of losses. The highest percentage of losses (around 40%-60%) in distribution networks occur in the LV systems, so micro-generation is well placed to make a significant contribution to loss reduction. Generators connected at LV offer not only potential for loss reduction at LV but also at higher voltage levels by reducing net energy flows from higher voltage to lower voltage.

Location, in the context of rural versus urban, will also drive the impact that DG can have on losses at this level. Typically rural locations, with longer network connections to remote locations are more susceptible to losses. So location in this context will also drive the magnitude of impact that DG can make. The study by (Cao et al., 2006) quantifies the impact of μCHP and PV on the distribution network losses in both rural and urban locations.

The results of the studies are summarised in Figure 3-12 (a&b). The losses are given in the percentage of annual energy consumption. In the UK, the average distribution losses are about 7% with losses in rural networks are significantly higher (mostly doubled) than losses in urban (city) areas. This can be understood since customers in rural areas are more clustered and connected via longer and smaller conductors compared with customers in the city.

Thus, the effect of deploying μCHP and PV is more apparent on the rural systems. The level of losses can be reduced by 41%, from 8.5% to 5% of annual energy consumption, by μCHP with total installed capacity of 50% of the total Grid Supply Point (GSP) peak load. In urban areas, the same capacity of μCHP reduces the level of losses from 4.5% to 3% (33% reduction). Application of PV also shows similar trends but significantly less in magnitude. With the same installed capacity (50% of peak demand), the reduction of losses is about 1.5%. This is less than half of the benefit obtained by micro-CHP. Given that the peak output of PV is not correlated to peak demand especially in the UK, PV contribution to loss reduction will not be as significant as μCHP.

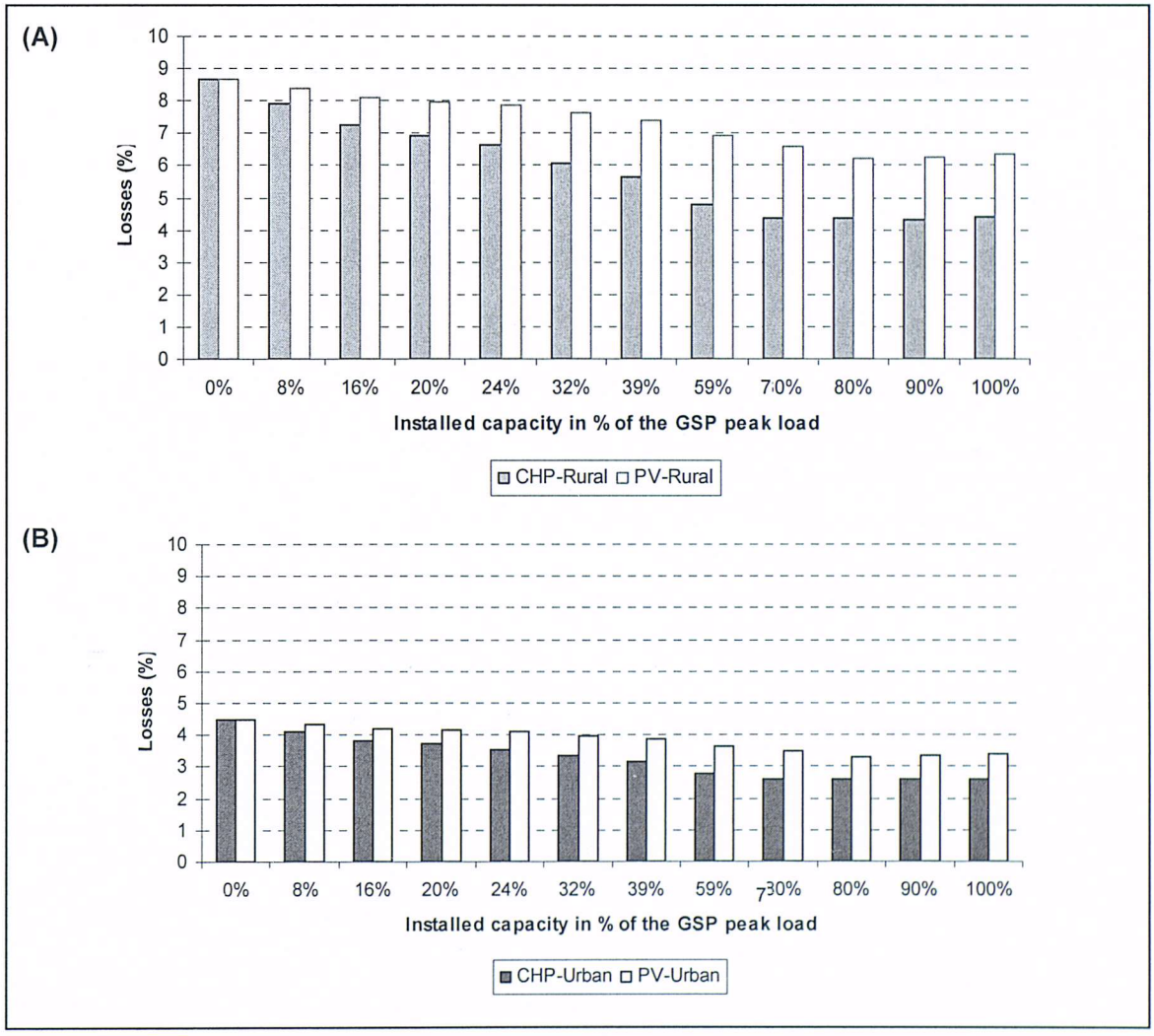


Figure 3-12: Contribution of μCHP and PV on the reduction in distribution network losses in (A) Rural areas and (B) Urban areas (Cao et al., 2006)

Density of installation

Density of installations also has a significant impact on the pattern of losses. As illustrated in Figure 3-12a, successive increases in capacity of μCHP bring down losses to just under 4.5%. However, at around 70-80% penetration the benefit to losses levels-out, and as penetration continues to increase losses increase moderately. This demonstrates the characteristic of distribution networks with significant DG penetration, whereby reverse energy flows (from lower to higher voltage) occur if demand is less than generation. For example, where low electricity demand is coincident with high heat requirement (e.g. early mornings) this may cause reverse flows on the network, which could require additional network management/reinforcement solutions and may erode the loss benefits if generation starts to drive peak flows. In this case, additional micro generators increase system losses.

3.4.3 Distribution network investment

The main investment drivers in distribution network design are:

- Network security; the need to satisfy network security requirements by investing in adequate network capacity
- Network losses; the need to strike an optimal balance between operating costs and network investment
- Service quality expenditure required to improve network performance indicators e.g. Customer Interruptions (average number of interruptions per 100 customers per year) and Customer Minutes Lost (average duration of interruptions per customer per year).

Contribution to security of suppiy for demand

Network security, based around providing sufficient network resources to secure load in the event of network failure, can be augmented to include the contribution of DG (Allan and Strbac, 2002).

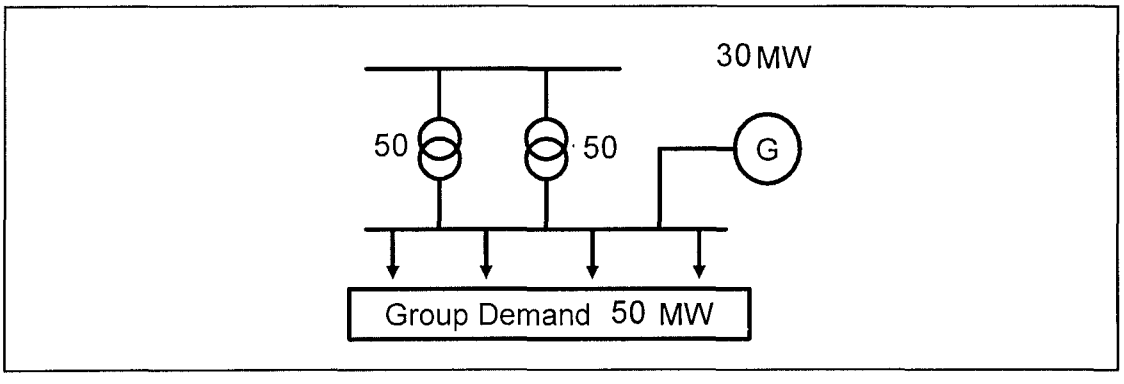


Figure 3-13: Example of secure network design without generation contributions

A simple example is set out in Figure 3-13 and illustrates how a DNO traditionally ensures security of supply in a 33/11 kV demand group through network design (Ilex and UMIST, 2004). As can be seen, the group demand of 50 MW can be supplied through either distribution circuit such that if one circuit were to fail, the group demand could be accommodated through the remaining circuit. In this example, the DNO ignores the presence of the generator and no security contribution could be allocated to this resource.

If the group demand in the above example were to grow to 55 MW, the supplying network would no longer be compliant, thus requiring the DNO to seek additional security contributions. Figure 3-14 illustrates two different approaches available to DNOs, which would secure sufficient additional security for network compliance. Assuming no generator contribution could be utilised, the DNO is forced to seek a network solution and install a third circuit to meet the security shortfall (Figure 3-14A). Alternatively, the DNO can utilise the contribution of the generator. Assuming availability of the 30 MW generator resulted in a security contribution of 60%, an overall security contribution of 18 MW could be recognised for network planning purposes (Figure 3-14B). Through the addition of the generator security contribution, the original network becomes compliant and network reinforcement is mitigated.

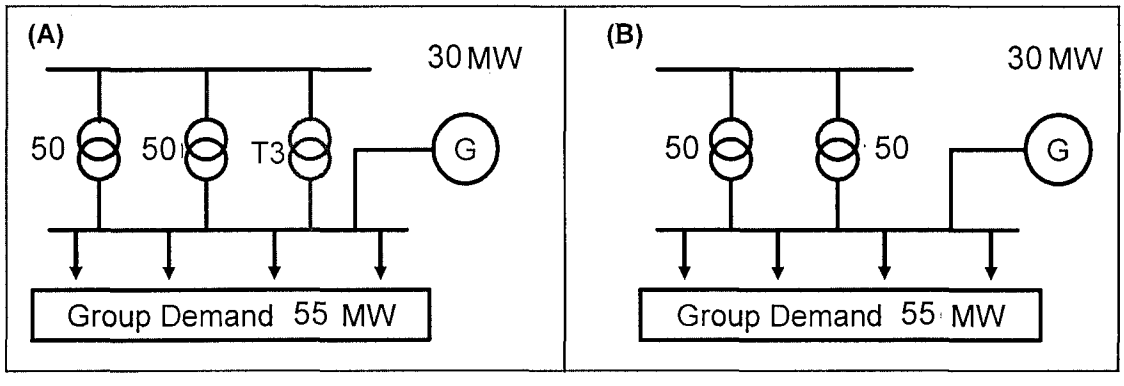


Figure 3-14: Network (A) and non-network (B) solutions to a distribution network security of supply shortfall.

This contribution of DG to securing load has recently been recognised through adaptation of the Engineering Recommendation P 2/6 (as highlighted in Chapter 2) (Allan et al., 2004).

Drivers of contribution to security of supply

Location

The performance of 11kV and 0.4kV networks has a dominant effect on the overall quality of service seen by end customers. The vast majority of interruptions (about 90%) have their cause in these networks (Ilex and UMIST, 2004). This is primarily driven by the radial design of these networks, as any fault on a circuit leads to an interruption to some customers (unlike

transmission and higher voltage level distribution networks that operate as interconnected networks). In line with this, generation located below the fault (i.e. closer to load) is able to make the most significant contribution to securing the load.

Time of use and availability

Time of use and availability of generation have a significant impact on the contribution that they can be relied upon to provide for network security. The new P 2/6 recommendation takes account of such issues in its development of "F-factors" for intermittent and non-intermittent generators[27]. These factors form part of a deterministic calculation that indicates the level to which various technologies can be relied upon to contribute to network security according to the number of units considered.

Reduction of power flows at higher voltage levels

The output of some DG technologies will reduce the net import energy from transmission to distribution networks during peak demand conditions, decreasing network peak loads and the requirement for capacity. This effective release of capacity from local generation can be used to accommodate load growth in the lower voltage network without the need for additional reinforcement. Thus, the connection of some DG technologies can defer the future network reinforcement and reduce the stress of the system which is likely to improve the lifetime of the assets. The following discussion focuses on the potential of μCHP to impact network flows and the drivers that moderate the magnitude of this effect.

Drivers for reduction of power flows

Location

DG generally has most impact on the network design at and above its level of connection. In general smaller scale generators tend to be connected to lower voltage levels than larger DG schemes. In this context, small scale generation that is located closer to demand will have higher relative value than large generation schemes connected to higher voltage levels, because it is better place to serve demand and mitigate power flows higher in the network. However, it is also important to remember that a significant proportion of the network costs are in assets operating at 33kV and below. So although it can be beneficial to reduce network requirements at higher voltage levels, this may be outweighed by the requirement for additional capacity to support additional low-voltage connections.

[27] See Table 2-3 and Table 2-4 on page 66 for full elaboration of the F-Factors for DG.

Size, magnitude and diversity of generation and demand

The number of generators and generation technologies plays an important role in the reduction of power flows at higher voltage levels. This is due to increased diversity which has the effect of firming up the output and increasing the contribution that local generation can make to meeting load requirements. This in turn reduces the demand for access to the higher voltage networks for transport of power from the transmission network.

Time of output and capacity credit

As discussed above, unlike many other DG technologies, μCHP can make significant reduction in the amount of conventional generation capacity required to meet system peak demand, resulting in a relatively high capacity credit (Hawkes and Leach, 2007). μCHP output, typically coincident with the winter peak demand condition, effectively reduces the demand at the winter peak, thus reducing the capacity required to maintain system security. Averaged across many CHP units this effect would be fairly predictable and reliable, so μCHP may not increase the need for reserve, and can actually displace existing capacity. Conversely, wind has a low capacity credit and produces disproportionately more energy than it displaces in capacity (Jenkins et al., 2006). Generators that are expected to operate during winter peak demand condition (such as μCHP), contribute to a reduction in the requirement for network capacity and would reduce the need for distribution network assets (or for network reinforcement).

Density of installation

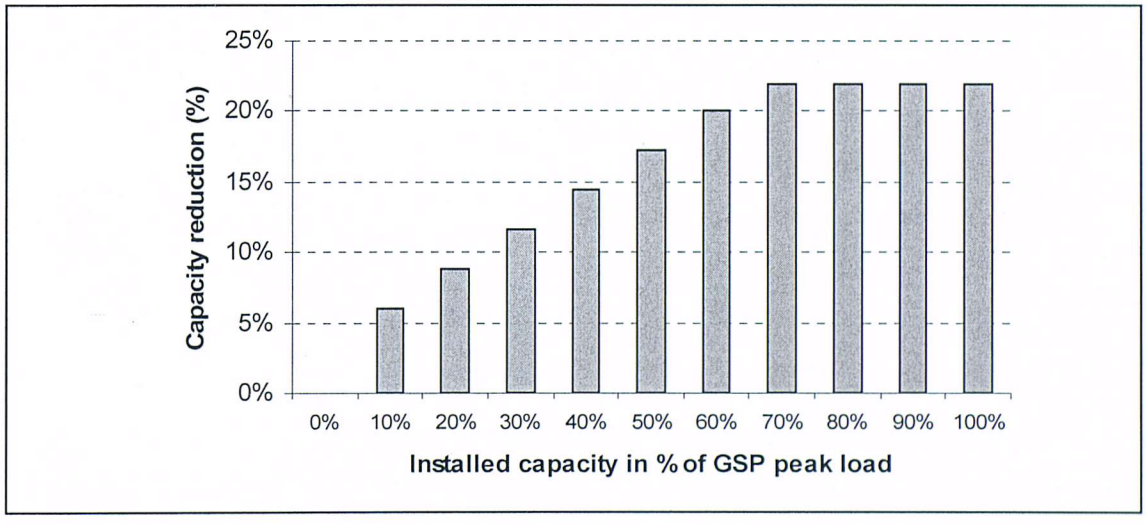


Figure 3-15: Contribution of μCHP on the demand for network capacity (Cao et al., 2006)

The study carried out by (Cao et al., 2006) revealed the potential capacity reduction that can be obtained from various levels of penetration of μCHP. The results are summarised in Figure

3-15. It can be concluded that μCHP can be used to reduce up to 22% demand of network capacity. This is obtained when μCHP generators are installed at 70% of the customer premises. Increasing further the penetration of the CHP will not further reduce the capacity since the critical capacity now is determined by load conditions where μCHP does not operate, for example the summer peak load.

3.4.4 Summary and Conclusions

Total capital investment from all UK DNOs during the period 2005-2006 was £11.17 billion (Ofgem, 2007a). The present penetration of distributed generation in the UK network sits at around 12.7GW, with approximately 4GW of this as CHP installations, and 3.5GW of renewables[28] with the remainder as gas-based generation primarily at the higher voltage levels. These installations are fairly evenly dispersed across the GB system. Approximate predictions from the UK DNOs have forecast penetration to increase by 7GW up to 2010 (with a corresponding increase in demand of around 3.5GW). This section has demonstrated that DG can have significant impact on the distribution network, both at operational and investment levels. However, the analysis has also shown that the magnitude of that impact is highly sensitive to levels of penetration and density of the installations.

In some areas it is clear that the penetration of distributed generation on the distribution networks is not yet large enough to have a material impact on the way that the network works as a whole. Take for example the reduction of voltage rise effects in rural areas using active management techniques. For penetrations of CHP/DG at around 5GW and below, the actual impact on the network is negligible. The introduction of active management at this level is not required for straightforward network access to be achieved. There will be pockets of more extreme problems, for example at the end of long rural feeders with wind turbines connected at the very end. But at present (and in the short to medium term future) these problems are an exception to the norm justifying specialist attention rather than a wholesale conversion of operation philosophy to accommodate DG network access.

Furthermore, within the distribution network investment and planning guidelines, the developments that have happened and are in progress to date are keeping pace. Such as, for example, the developments under P 2/6 and the ongoing discussions to develop the DUoS charging mechanism, to integrate more explicit inclusion of generation in a locational long term investment cost related framework similar to the existing TNUoS charge.

[28] See Table 2-1 on page 36 for the full detail of distributed generation installed in the UK.

Problems do exist, and there are areas where the connection of DG has a significant network impact that drives reinforcement or other network investment. Particularly in sparse rural networks the entry of generation is likely to have an impact that cannot be recognised in the current access arrangements. However, the existence of these one-off, specialised issues cannot justify wholesale change of the solutions for network reinforcement, and operation that govern the current network. Until the penetration of generation into the network presents a material problem this remains a second order concern to transmission issues, and one that is already being kept under a watching brief through a number of initiatives such as the Registered Power Zone and the Innovation Funding Initiatives (Ofgem, 2005b). As such, the remainder of this thesis is devoted to the discussion of transmission access related issues. These concerns are presenting an immediate challenge in the short to medium term, and will be taken forward to fulfil the aims and objectives of the thesis in the following two chapters.

3.5 Implications and Conclusions

The aim of this chapter was to explore the impact of renewables and DG on the transmission and distribution networks in terms of access over operational and investment timeframes. The impact assessment allowed deduction of the characteristics of non-conventional generation that have a crucial impact on the driving network access requirements. This highlights the core areas that must be adequately represented at the regulatory and market level to ensure cost reflective and optimal arrangements for all generation technologies.

The assessment revealed that at both the transmission and distribution levels the importance of recognising the spatial and temporal characteristics of non-conventional generation is crucial. It is these specific attributes (such as time of use of the system, coincidence with system peak, voltage level connection, geographic location in the GB system etc) that represent the material differences between conventional and non-conventional generation, and ultimately drive different impacts on both the operational and investment horizons for network access.

The movement towards consideration of more specific spatial and temporal characteristics of generation in the access arrangements signals another step towards fully market based solutions to access questions with a focus on the short(er) term. This presents the main challenge to the status-quo approach to network development and operation firmly rooted in pre-defined and deterministic standards for transmission and distribution network access.

The following chapter takes up this discussion, analysing and evaluating the gaps in the current transmission access arrangements that affect the optimal development and operation of the network. The main findings from this chapter on the needs and requirements of non-

conventional generation at transmission level will be drawn into this analysis. A framework will also be developed to explore the opportunities for developing of new enduring arrangements to reflect the need identified in this chapter for a move towards shorter term and increasingly market based solutions for transmission access challenges.

CHAPTER 4: Transmission network access arrangements for systems with renewable and distributed generation

4.1 Introduction

This chapter evaluates the current transmission access arrangements to determine whether they offer a fair and optimal framework for a power system characterised by significant penetration of renewable and distributed generation. The critical analysis of the current arrangements identifies a number of inefficiencies in the current arrangements that are favouring conventional generation at the expense of providing efficient access for wind generation. It also highlights some fundamental flaws in the treatment of demand and distributed generation that are distorting the market and presenting a barrier to optimal transmission access. The chapter then builds upon these outcomes by exploring solutions to the key inefficiencies identified in the existing access arrangements and proposing a framework for the development of new enduring access arrangements. Three options for new enduring arrangements are proposed and evaluated against the proposed framework to determine their suitability.

Through the reviews and analysis presented in the previous chapters, the scale of the challenge in network access has been identified as being most relevant in the transmission networks. With high levels of wind generation pending connection in an already congested area of the network there is material change facing the transmission network. The impact and implications of integration of significant levels of wind generation into the system raise some key challenges; firstly, how to make timely connection of renewables on to the network in the short term, and secondly, how to address the longer-term issues on the development of enduring arrangements to create a cost-reflective environment for new (non-conventional) generating technologies? These factors are driving the requirement to act now and ensure that the market and regulatory arrangements for network access are fit-for-purpose and not preventing the creation of a level playing field for non-conventional generation technologies. This is reflected in the number of Industry and Government Groups currently addressing this issue (e.g. Ofgem, 2005a, NGET,

2007c) and in a call for a full review of transmission access in the recent Energy White Paper (DTI, 2007, Ofgem and DBERR, 2007).

Although there are a considerable number of issues and developments at the distribution level, the penetration of generation into the distribution network (now and that predicted) is not sufficient to cause widespread disruption in the network. As such the benefits from improved access to distribution have limited material value. Hence, the focus of the remaining chapters of this thesis is on questions of transmission access, for both transmission and distribution connected generation. Where relevant the issues for distribution network access are briefly elaborated on, and Chapter 6 is used to detail further work.

However, it should be noted that the analysis will include consideration of the current transmission arrangements for DG. Although DG may not presently be at levels in the distribution network at which it has a material impact, there are certain aspects of the transmission access arrangements that must include consideration of DG if they are to be fully cost reflective. Of particular importance is the interaction between transmission connected generation, DG and demand. At present the transmission access arrangements are not synchronised across these network users, and recognition of one requires equal recognition and consideration of the others. Furthermore, there are opportunities for generation technologies with fuel switching capabilities to have greater involvement in transmission operation and development. This is particularly relevant for industrial scale CHP, prevalent in the distribution network. Finally, the development of new transmission arrangements must be capable of consistency across generation technologies, so that if and when distributed generation does arrive the arrangements can accommodate this and make allowance for the differences in granularity of inputs (accounting for output by minutes and even seconds may become increasingly important for DG), and sheer numbers of units that must be incorporated (this is discussed in Chapter 6, with the development of the Virtual Power Plant technical architecture for facilitating visibility of DG at transmission level).

4.2 Evaluation of the current transmission access arrangements

To measure whether efficient access is being facilitated by the current arrangements depends on whether users are being charged according to their use of (and impact on) the system. To contribute to the understanding and analysis of this question, Chapter 2 reviewed the current arrangements for transmission and distribution network access, laying out the philosophy for physical development of the networks and describing the evolution of the current supportive regulatory framework. Alongside this, it identified the principle features of a future system with

a significant penetration of non-conventional generation and highlighted the gaps and challenges in the current framework that may prevent full, fair and cost reflective network access in the future system. Chapter 3 then identified the impact (costs and benefits) that renewable and distributed generation have on the networks.

Drawing these two previous chapters together, this section determines whether the current framework is suitable for application to the future low-carbon system, in the context of maintaining a fair optimal and efficient transmission system based on competitive market principles and cost reflectivity. The evaluation identifies the main inefficiencies in the present transmission access arrangements that impact cost reflectivity for systems with non-conventional generation. It begins by briefly highlighting the key characteristics of transmission access requirements in systems with transmission connected wind generation and distributed generation (derived in Chapter 3). This is followed by a critical analysis of the current arrangements for transmission investment, access and pricing (as set out in Chapter 2) in the context of these access-characteristics for non-conventional generation.

4.2.1 Characteristics of transmission access requirements for wind, DG and demand

To determine the cost reflectivity and efficiency of the present access arrangements on renewable and distributed generation it is necessary to highlight the main characteristics and requirements of this non conventional generation that differ from those presented by conventional generation. These characteristics of transmission access for wind generation and DG are extrapolated from the findings in Chapter 3.

Wind generation operating patterns and timing of network usage

Wind generation is significantly different to conventional generating technologies for which the current arrangements were devised. The current arrangements were developed on the basis that generation technology would be operating at maximum output during times of peak system operation (i.e. peak demand, which is coincident with peak prices). In the context of transmission planning and pricing there is an assumption that all conventional generation operates during system peak. Therefore, it has been reasonable to design transmission on the basis that during peak demand conditions all generation will require full access to the network.

Wind, however, is dependent on the weather conditions to generate, and correlation between peak demand conditions and output are very weak. Output from wind generation is very variable (intermittent), generally inflexible and generators cannot optimise their output according to price signals. Output can be predicted to a certain degree, but forecasts for

generation become increasingly accurate closer to real time. These differences in operating characteristics and time of use of the system have a fundamental impact on the way in which wind generation uses the system and drives investment in transmission. At present this is not reflected in the commercial and regulatory arrangements that govern transmission investment, access and pricing.

Shared transmission capacity between conventional and wind generation

When addressing transmission system reinforcement to accommodate the connection of new generation, consideration of the cost-benefit implications of connection may justify the installation of additional network capacity to allow efficient utilisation of low marginal cost generators. Decisions taken to reinforce transmission can be justified if the savings in the marginal reduction in generation costs (marginal cost of constraints) are greater than the marginal transmission network investment cost.

Given that it is generally significantly more costly to curtail wind than invest in transmission, in areas dominated by wind power, with limited scope to constrain off conventional generation (on windy days), the optimal capacity of transmission should be equal to the installed capacity of wind power. However, in areas with a mix of conventional and wind generation, transmission capacity need not be built to accommodate the simultaneous peak output of all generation. Instead an optimal amount of network capacity should be provided and shared between wind and conventional generation, with conventional generation being constrained off on windy days when wind output dominates capacity. The cost-benefit approach illustrates that economically efficient transmission investment is made when the opportunities for sharing of transmission between different generating resources are recognised.

Wind generation also makes less use of this shared capacity than conventional generation; therefore wind will also tend to drive less transmission investment. Discrimination between generation-types and location to reflect these differences in operation characteristics and output is essential if optimal decisions are to be made in transmission investment and if cost-reflective pricing regimes are to be devised for accurate reflection of generation costs imposed on the system.

4.2.2 Access requirements for distributed generation and demand

Integration of DG into transmission access arrangements requires recognition of two key factors:

i) The impact of diversity in generation and in demand on the net flows at the transmission-distribution boundary
ii) The influence of the distribution network on the impact that individual demand and generation units make at the transmission distribution boundary

For the transmission system operator to undertake system balancing tasks and to signal terms of usage to drive optimal transmission investment requires quantification of the net flows at the transmission-distribution boundary (the GSP). This includes the contribution of both DG and demand. To calculate this accurately requires not only the net value of demand requirements and generation output but also consideration of the distribution network and its impact on energy flows before they reach the GSP. The distribution network links DG, demand and the transmission system (via the GSP). This network, through constraints and losses (both active and reactive), can significantly modulate the characteristics of distributed resources that are seen by the TSO. The distribution network topology changes in real time as the relationship between generation output, imports, exports and demand requirements fluctuate and change. As such, representation of the network contribution to the impact of individual DG on transmission and on net flows at the transmission boundary is fundamental to achieving cost reflective transmission arrangements.

Effectively, if the distinction between transmission and distribution networks is maintained, the multiple resources behind a GSP in the distribution network must be presented to the TSO as a single resource, similar to any transmission connected generator or large demand customer. The characteristics of these distributed resources (demand and generation) should be combined with the impact of the network. This creates a single output profile, with a single set of operating parameters and cost characteristics that represent the net ability of the entire portfolio. For transmission operation and investment purposes it is this aggregated profile that is most relevant – rather than the individual activity of hundreds and thousands (and potentially millions) of separate units. The following sections assess how well the current arrangements address the provision of transmission access that meets these requirements for representation of a net profile of a portfolio of resources. Characterisation of DG, demand and the network as a VPP presents another challenge that is addressed in the subsequent chapter.

4.2.3 Recap of the current transmission access arrangements

A detailed explanation of the current transmission arrangements is provided in Chapter 2. However, to aid clarity of the following evaluation, an overview of the current transmission access arrangements for transmission and distribution connected generation is made below to recap the key areas of the arrangements that will be scrutinised in the following sections.

Transmission connected wind

Currently, all generators wishing to connect to the transmission network must apply for Transmission Entry Capacity (TEC) that represents their maximum expected export value onto the network. At present, the "invest then connect" philosophy dictates that TEC will not be issued until there is sufficient capacity on the network to accommodate the new generator, and generators cannot be connected to the system without TEC[29]. In return for TEC, generators receive a guarantee of firm long term access to the transmission system and compensation (from the TSO) if transmission congestion prevents their use of this access right. TEC is used as a proxy to indicate user demand for transmission capacity, so is used as justification for network expansion where there is not sufficient capacity to accommodate all TEC requirements.

Charging for use of the transmission system is via the Transmission Network Use of System (TNUoS) charge; this is a locational charge, based on the marginal investment costs that generators impose on the system. The TNUoS charge uses TEC as a user defined indication of capacity requirements for new generators. Allocation of short term costs of access (i.e. transmission constraint costs) is executed via the Balancing Service Use of System (BSUoS) charge. This is a socialised charge made to all users of the system (generation and demand) on the basis of their traded volumes in the wholesale energy market.

There is currently no user choice in purchasing of access to the transmission system; this is done only on the basis of firm long term access. There is no locational pricing of short term access that would provide users with the opportunity to purchase access closer to real time.

Distributed generation

At present, most generators under 100MW embedded in the distribution system are exempt from TNUoS charges and have no formal interaction with transmission. To operate in the market DGs usually contract with an energy supplier for inclusion in their Supplier Volume Allocation (SVA). Suppliers with DG in their portfolio treat it as negative demand. They can deduct power produced by DG from their total demand requirements in a particular area, and thus pay a reduced level of demand TNUoS charges. These "embedded benefits" will usually be taken into account when DG are negotiating a contract (or power purchase agreement) with a Supplier. For DG that want to export to the transmission network or take part in the various transmission related services there are two access products the BEGA and the BELLA that can facilitate this interaction.

[29] This means that new (wind) generation in Scotland cannot be connected until the necessary system reinforcements have been made.

4.2.4 Evaluation of the current access arrangements for systems with wind

At present, the regulatory arrangements and "invest then connect" philosophy dictates that new (wind) generation cannot be connected until the necessary system reinforcements have been made. However, the current frameworks for transmission investment, access and pricing have been developed for systems with conventional generation. As such they are not optimised to reflect the requirements of non-conventional generation as outlined previously and are fundamentally incapable of making an accurate assessment of the transmission capacity requirements for these technologies.

In addition there are implications for cost reflectivity of a regime that only facilitates purchase of long term firm access. For wind generation where exact access requirements will be dependent on variable weather conditions, the lack of a real time market based approach to access calls into question the transparency and competitiveness of the current arrangements.

This section explores these market and regulatory inefficiencies through evaluation of the current arrangements, namely TEC and the TNUoS and BSUoS charges.

Evaluation of the TEC approach for long term investment and pricing

Although the concept of TEC is attractive in principle, and an appropriate proxy for systems consisting of conventional generation, the key problem of the present implementation and interpretation of this instrument is its inflexibility and lack of discrimination between generating technologies. This results in a lack of consistency with the transmission investment process, and transmission network pricing and impacts adversely on the efficiency of generation system operation.

For wind, the TEC associated with an individual generator will not be directly linked with the need for transmission capacity on the main interconnected system, particularly in systems which feature a diversity of generation technologies, as capacity can be shared. It is clear that different (non-conventional) generation technologies may drive different levels of investment in the main transmission network. This is primarily due to variation in output over time that is not correlated to either demand or generation from other sources. This variation cannot be reflected in the value of TEC, which is a static measurement, allocating a fixed volume of capacity throughout its duration.

The process of converting TEC into investment capacity decisions is also not clear. The present approach to assessing the need for transmission capacity between large areas does not

adequately take into account the effect of diversity in output and corresponding requirement for transmission capacity, which is fundamental to achieving efficient development of the network. Gross treatment of access requirements (i.e. summing of TEC to determine access requirements) fails to recognise the significant diversity in output of generating technologies, and the opportunities for wind (and demand) to share transmission capacity with conventional generation.

The absence of a link between TEC for wind/non-conventional generation and the requirement for transmission investment means that the concept of TEC, in its present format, cannot provide the basis for optimal transmission reinforcement when evaluating the impact and requirements of non-conventional generation. Given that the TEC allocated to wind is not directly applicable in determining the impact that the user makes on long term marginal transmission investment cost, using TEC as the basis for the generation TNUoS charge for systems with significant penetration of non-conventional generation is also flawed and will fail to achieve cost reflectivity.

Implications of the inflexibility of TEC, access choice and the need for valuing transmission

Further to the implications of TEC on long term transmission investment and pricing, TEC may also impact operational efficiency for generators that purchase a lower amount of TEC than their installed capacity. In this instance a generator would be prevented from generating in excess of its purchased TEC allocation, irrespective of whether the network is congested or not. This is inefficient, as these users are unnecessarily prevented from accessing the transmission network (and hence the energy market) when the short term marginal cost of using this transmission capacity is minimal (close to zero).

In addition, limitation of access products to TEC does not provide sufficient choice for participants, or the opportunity to balance a long term access position against short term availability of transmission capacity. Most new wind generation projects require a guarantee of firm access (i.e. TEC) to secure investment backing. However, as there is no alternative to TEC and access is a pre-requisite for financial support, long term fixed access is the only option for new projects. Development of alternatives to TEC such as products that offer firm access over a range of timescales (from intra-day to long term access to transmission) could provide more choice to developers and investors, whilst still giving an assurance of access.

Figure 4-1 provides a simple example to illustrate the inappropriateness of a single inflexible TEC product in a system with wind and conventional generation and to highlight the need for

valuing transmission through access choice. In this example a conventional generator with maximum output of 800MW is connected to the same bus-bar as a wind farm with a peak output of 700MW. The transmission line connecting this bus-bar to the rest of the system has been optimally sized at 1000MW (i.e. under a given set of parameters for cost of constraints, and investment, this line has been optimally sized to accommodate both generators). This sizing implies that it is not optimal to provide transmission capacity to meet simultaneous peak output from the generators and that the plant connected at the bus-bar should share transmission capacity.

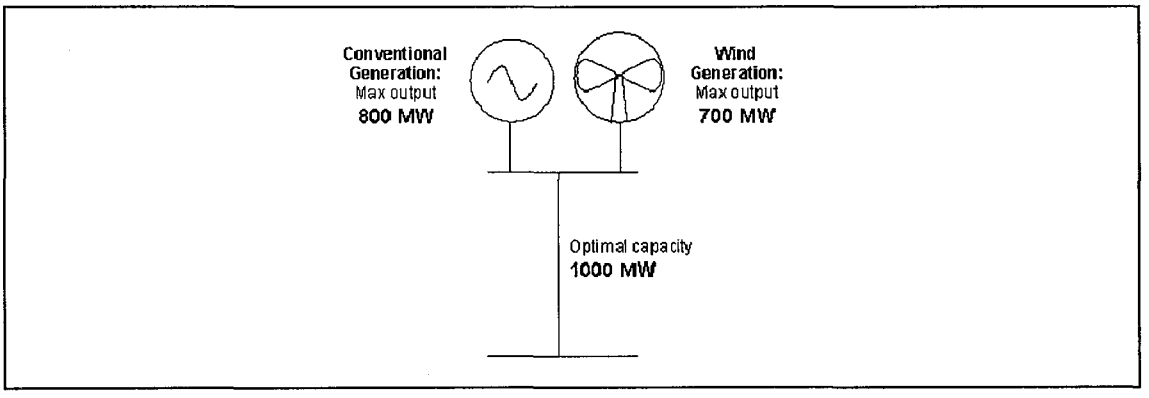


Figure 4-1: Example 2-bus system with conventional & wind generation sharing transmission capacity

Under the current arrangements, both the conventional generator and the wind farm must apply for TEC before they can be connected to the system. Both generators will want to purchase TEC to accommodate their peak capacity (a total of 1500MW). However, the optimal capacity for the line is 1000MW and the System Operator will not allocate more TEC than the sum of capacity available. To build additional capacity to accommodate maximum TEC for both parties would lead to economically inefficient constraint-free transmission.

The solution is that wind and conventional generation be allowed to share the capacity, but the limited TEC product will not allow this. To allow optimal allocation of capacity requires new products that facilitate trading of short term access between parties to permit cost effective sharing of this optimally constrained capacity.

For example, the wind generator, with zero marginal cost of operation and a high value of Renewable Obligation Certificates (ROCs), requests 700MW of firm access. The conventional generator purchases the remaining 300MW of firm access. Clearly, charges for the use of system will be based on these capacities. However, when the conventional generator is operating on non-windy days (e.g. where wind power output is less than 200MW), the it can run at full capacity of 800MW without the need to purchase any access (assuming that this situation

is perfectly predictable). The network will not be congested, so the ex-post access price will be zero. On windy days, the output of the conventional generator will be limited by the difference between the line capacity (1000MW) and the output of the wind farm. Given relatively low load factors of wind of around 30%, the conventional generator will be able to achieve a load factor of close to 80% of the plant rated at 800MW, while paying TNUoS charges for only 300MW.

Alternatively, if we assume that the conventional generator holds firm access rights of 800MW and the wind generator holds the remaining 200MW, on a windy day, with a potential wind power output of 700MW, the conventional generator may sell (via auction or bilaterally) 500MW of access rights to wind generator. The short term marginal cost of access will be equal to the fuel price differential of the cheapest generator that was constrained on (in the importing area) and the conventional generator that is constrained off. However, the short term value of this access rights may be higher and reach the cost of curtailing wind output (i.e. the marginal cost of operation plus the value of ROCs). This example illustrates that the value of firm access rights to transmission may be higher for wind than for conventional generation.

Unequal treatment of demand and generation

In principle, when the system is dominated by conventional generation, the TEC and TNUoS approach creates an optimal network and a cost reflective charge for generation. However, even for a conventional system, this approach is not wholly efficient as the method treats generation and demand differently. Generation and demand in the same location have equal but opposite effects on the system. Yet at present, different methods are used for calculating generation and demand requirement for transmission access and contribution to investment costs. There is no TEC equivalent for demand, so demand has no opportunity to stipulate how much access they require, or any autonomy to release access for generation (through increasing local demand)if this becomes economically favourable.

Regarding TNUoS and pricing of long term access, overall charge is weighted 27/73 on generation and demand users with demand responsible for the greater share. To encourage demand to take an active role in network investment and operation, cost reflective charging should reflect the physical system and allow all users of the system to receive and react to appropriate price signals that reflect their impact on the system. This means treating demand and generation equally, allowing demand to stipulate access requirements, exposing them to cost reflective charges, and allowing full participation in any market based arrangements.

Lack of transparency in BSUoS charges

The BSUoS charge represents the aggregated short term costs of constraints across the system. It is socialised amongst all system users (generation and demand) according to their traded volumes in the energy markets. This concept of a socialised BSUoS charge is consistent with concept of TEC. The TEC approach is based on long term firm access for generation according to their stated maximum requirements. If the System Operator cannot provide this access, then generation that is not in breach of its TEC is entitled to receive compensation for being constrained off the system due to insufficient capacity.

The non-locational BSUoS charge is necessary to ensure that system users are not compensated (or charged) twice for actions taken to resolve short term system constraints. By socialising the short term costs of balancing the system all participants bear the costs of constraints equally and cost reflectivity is maintained through the long term pricing regime (although whether this is cost reflective for non-conventional generation is uncertain, as elaborated above).

Socialising the BSUoS charge, although necessary to support the current TEC based arrangements, means that there is no explicit signal presented to users regarding the short term value of transmission in congested areas. Without an efficient indication of the short term value of access, system users will not be able to make rational decisions regarding their use of the system. Furthermore, justification of reinforcement activities of the System Operator is less transparent and inefficient. Without accurate price signals the charging methodologies (BSUoS and TNUoS) are just ad-hoc instruments to ensure cost recovery for the System Operators and Network Owners, rather than a method to signal future costs of use of the system to users and facilitate its efficient development.

Lack of transparency from long term investment based pricing approach

Previously, physical system was built on the basis of peak network conditions, with the presumption that all generation connecting to the system would be purchasing TEC equivalent to the value of their maximum output, and that most generators would want to be generating to that maximum at times of peak demand. Under these conditions it is reasonable to use the sum of the values of TEC as (part of) a proxy for network capacity required to allow generation to meet demand during peak times. There is no need for sharing under these conditions, because at peak conditions generators do not want to share, so the network is sized accordingly. Long-run investment based pricing is a suitable proxy for the cost of the network as it is driven by these peak conditions, that all generators participate in with some regulatory and predictability. However, introducing the concept of sharing capacity when it is economic to do so into the design and operation of the transmission network is a fundamental change to these

presumptions. Sharing of capacity is possible because wind generation does not use the system in the same way as conventional generation. Therefore peak output is not (deliberately) coincident, and it may not be optimal to size the network to be sufficient to meet coincident peak output that occurs on an infrequent basis. The analysis shows that sharing of capacity is a more economic solution. However, there will be times when system users want to use more capacity than is physically available. In this instance there should be an option for users to optimise their access requirements balancing the short term value of transmission against the cost of curtailing output. Users need to express choice according to how the capacity should be used at times when both parties want to use limited transmission resources.

The challenge for the current arrangements is how to place a value on access in the short term (i.e. when the system is constrained). Long term investment based pricing is not able to capture this value, although charging based on the Long Run Marginal Cost (LRMC) should equal the solution under the short run cost (in an ideal system). The TNUoS charge is not sufficiently cost reflective or flexible to provide a value for real time usage of the system. To reflect this value and provide choice to system users, the Short Run Marginal Cost (SRMC) of access needs to be derived by location across the network. This SRMC should represent the real-time value of transmission. i.e. an ex-post assessment of the spot price of transmission on a half hourly basis as per the current energy markets, with the additional element that it is also calculated by locational (this could be nodal or zonal). Derivation of the SRMC for transmission essentially requires consideration of the Locational Marginal Pricing (LMP) approach, but maintains the separation of energy and access. Further discussion of this sort term valuation of access and development of an ex-post market for access is discussed in section 4.4.

This situation and need for quantification of the short term value of transmission does not arise in the current system, because there is little incentive (or option) for conventional system users to trade access in the short term. However, when sharing of access is possible it may be an appropriate risk management strategy for conventional generators to operate primarily in the short term markets (when the system is not congested and therefore access has zero value/is zero cost) and hedge their position during peak network times when congestion is more likely. By introducing the SRMC aspect this gives users the opportunity to decide how much access they require, and for the system operator to charge accordingly. It thereby provides users (all users, including demand) with a genuine choice of access products and the opportunity to react to real time conditions.

4.2.5 Implications of current market and regulatory arrangements for wind access

The current market arrangements separate consideration of energy and access and send no locational signals to users of the system on their short term impact on the system. This prohibits system users from taking action to optimise their requirement for transmission. In the longer term, the current TEC based approach to transmission investment and pricing cannot facilitate cost effective and timely integration of substantial amounts of non-conventional generation into the UK transmission system. Fundamental revision of the concept of TEC (that could include its removal as an option) to reflect the diversity of different generating technologies is essential if transmission access and related arrangements for wind are to be cost reflective and transparent. The analysis in the previous section demonstrates that the present regulatory and market arrangements have two major flaws:

i) inability to deliver economically efficient transmission solutions in both short and long term
ii) discrimination against non-conventional generation in favour of conventional generation

The present transmission access regime forces all users to acquire long term TEC for all their output in order for investors to consider their projects to be financially viable, as there is no other choice available. This leads to inefficient investment in transmission capacity as this fundamentally undermines the concept of sharing of transmission assets, which is shown to be economically optimal. As cost reflective short term value of access is unavailable this regime does not provide choice for (new) generators and prevents them from making efficient decisions regarding their location and use of the system in the short and long term. This results in inefficient operation of the generation system and inefficient investment in transmission. This has the ultimate consequence of increasing the cost to the end consumer which demonstrates that the present access framework is inherently inefficient when it comes to a system with significant penetration of wind energy.

Furthermore, given that wind generation tends to drive less transmission investment in exporting areas, the present TNUoS charging regime overcharges. The TEC concept excludes demand and the related charging arrangements charge demand users unequally with regard to generation; this is both inefficient and discriminatory.

4.2.6 Evaluation of current transmission access arrangements for distributed generation and demand

This section evaluates the impact of the lack of interaction and accountability between DG and transmission, and highlights the potential inefficiencies that the current arrangement may stimulate, including cross subsidy (between conventional transmission connected generation and DG) and perverse incentives to connect to the distribution network. For comparison with the analysis on transmission connected generation, the potential impact of application of the present charging arrangements (based on TEC) to generation in the distribution network is also undertaken.

It should be noted that the present arrangements, which treat DG as negative demand, also treat demand and transmission connected generation differently. Although generation and demand have equal and opposite physical impact on the network, the current charging regime does not reflect this with regard to transmission connected generation and demand. There are several key differences in the treatment of these two users of the system (NGET 2006):

- Generation charges can be positive or negative, but demand charges are only positive,
- Demand access charges are based on metered volumes (capacity used), whereas generation charges are based on user requests for firm access rights through the TEC, and
- TNUoS charges are levied 73% on demand and 27% on generation.

The principal objective of the transmission access and charging arrangements should be to expose parties to the cost that they impose in a non-discriminatory manner so that they can then make efficient investment decisions. However, with these discrepancies in the treatment of system users, it is unclear whether these cost reflective signals are being passed through to DG under the current charging arrangements. The current arrangements pose two challenges for DG access to transmission: (i) DG is not visible at transmission level, causing inefficiencies in transmission investment signals, and (ii) DG is treated differently from transmission connected generation, leading to cross subsidy and inefficient allocation of costs between generators connected at different levels of the system. Both of these issues are explored in more detail below.

Lack of visibility of DG to the transmission system operator leading to inefficient investment decisions

One of the main challenges to efficient and optimal system development under the current charging system is the lack of visibility of DG at transmission level. As demonstrated in chapter three, DG has an impact on the transmission system (e.g. through contribution to North-South

power flows), however, unless a DG plant operator chooses to take a BEGA or BELLA its activity is not visible and it is not accountable to the system operator. As penetration of DG increases, flows at the transmission-distribution boundary are changing. Historically, GSPs that link transmission and the 132kV distribution networks have imported energy from the transmission network onto the passive, uni-directional distribution network. However, the increasing penetration of generation into the distribution is seeing some GSPs exporting back on to the transmission network at certain times of the day, and applications have been made to the system operator for "no-demand" or export only GSPs (NGET, 2005a, Ofgem, 2005a).

Because most generators in the distribution network do not have the TEC allowance that would register their transmission requirements with the system operator they are not visible to the system operator. Where the activity of licence exempt generators leads to export onto the transmission system (or even alteration of the net flow at the GSP) they are impacting the system without being implicated in the charging structure (NGET, 2005a). The lack of a formal relationship between most DG units and the transmission system operator means that these generators are driving transmission capacity requirements without communicating those requirements to the system operator; as a consequence, the system operator is less able to translate signals on use of the system into efficient infrastructure investment decisions[30]. Furthermore, the lack of visibility for DG also renders it unable to integrate into the system and contributing to real-time operation through provision of ancillary services.

Unequal treatment of transmission and distribution connected generation and demand

Generation units embedded in the distribution network are usually registered with an energy supplier and the presence of DG serves to reduce the supplier's net demand position and associated TNUoS charges. This arrangement correctly treats DG as negative demand. However, because the wider transmission arrangements do not treat demand and transmission connected generation equally, the current arrangement also sets up a disparity in treatment between transmission-connected generation and DG that has consequences for the cost reflectivity of the arrangements.

Distribution and transmission connected generation is essentially the same. 1MW of power produced from a transmission connected generator is the same as that from a generator embedded in the distribution system. There will be factors such as location in the network and the time and pattern of use of the system that affect the ultimate impact of any generator on the

[30] Note that the impact of DG exporting on to the transmission network and changing net flows at the GSP can decrease as well as increase transmission capacity requirements. Up to a point, decreased import will reduce transmission connection requirements. Exporting GSPs will not automatically drive additional transmission capacity until it exceeds the transmission import capacity.

system, but fundamentally generation output is the same. If charges can reflect these differences in location and time of use, all types of generation should be subject to the same charging methodology to avoid cross subsidy and the creation of perverse incentives for generation to connect where it is not optimal to do so.

For example, under the current arrangements, "embedded benefits" are awarded to DG regardless of location. This is based on the principle that DG serves local load, reducing import flows and the requirement for transmission capacity. The "embedded benefit" does not recognise the fact that DG in the North of the UK will reduce local load, but that this will have the net effect of increasing North-South power flows and potentially increasing congestion and hence driving the need for transmission investment. Under the current arrangements a generator connecting to the transmission network in Scotland must pay TNUoS charges, because there is already more generation than demand in the North, so addition of more generation increases north-south power flows and the demand for transmission. DG in Scotland has the same effect, because it effectively reduces load in the North, however, DG in Scotland will confer embedded benefits in reduced demand TNUoS charges.

	Zone[31]		Tariff (£/kW)	Charge for 10 MW Gen or demand (£)	Charge for +5MW Gen @ Transmission (£)	Charge for +5MW Gen @ Distribution (£)[32]
South	Generation	Central London (16)	-5.49	-54,900	-27,450	-
	Demand	London (12)	19.78	197,800	-	- 98,900
North	Generation	North Scotland (2)	20.51	205,100	102,550	-
	Demand	Northern Scotland (1)	0.40	4,000	-	- 2,000

Table 4-1: Demonstration of generation and demand TNUoS charging in the North and South of the GB system, and the impact of adding 5MW of additional generation to transmission and distribution (NGET, 2007a)

Table 4-1 illustrates this discrepancy using current TNUoS generation and demand tariffs[33]. For transmission connected generation there is a clear locational signal in the TNUoS charge that rewards generation for connecting close to the demand centres in London with a negative charge (i.e. generators in the South are paid), whilst generators connecting in Scotland, where there is already a surplus of generation, are subject to significantly higher charges. Demand is also

[31] The GB system is split into 21 zones for consideration of generation charges and into 14 zones for demand. These areas broadly overlap, but are not necessarily concurrent.
[32] The additional "charge" from distributed generation is an embedded benefit claimed by the energy supplier to which the generation is registered under.
[33] The demand TNUoS tariff is split into a demand tariff (charged in £/kW) for half hourly metered loads and based on consumption during the TRIAD period, and energy consumption tariff (charged in p/kWh) for non-half hourly metered loads and based on daily consumption during peak settlement periods 33-38. For comparative purposes the example in the table only uses the demand tariff for half hourly metered loads, the same impact is seen if energy consumption tariff is used.

charged according to location. Loads in the South are charged more than those in the North, although unlike generation, demand charges are never negative (i.e. demand is never paid to use electricity). Generation, whether in the transmission or distribution networks, has a broadly similar impact on the system that it is connected to.

However, connection of an additional 5MW of generation to either the transmission or distribution networks in the locations used in the example above illustrates a discrepancy in their treatment under the current arrangements. Adding an additional 5MW to the transmission system in the South results in a £5.49/kW (£27,450 total) payment to the connecting generator; adding the same 5MW in the distribution network provides a £19.78/kW benefit (£98,900 in total) in reduced demand TNUoS charges. The charges confer nearly four times as much value on DG connecting just below transmission. Although the proximity of DG to load could be responsible for conferring additional value to this generation, this value will not be consistent throughout the distribution network and will be highly dependent on the surrounding network conditions, proximity of load, and other generation etc.

In the North of the GB system the situation is also skewed. 5MW of generation will be charged an additional £20.51/kW (£102,550 in total) for connecting at transmission level. The same generation connecting to the distribution network will confer a benefit of £0.40/kW (£2,000 total) to the energy supplier under which it is registered, despite the fact that connecting DG in the here will reduce local load, increase power export from the North to the South and increase the need for transmission capacity. In this instance, the embedded benefit is conferring nearly £20/kW of benefits from connecting to the distribution network, and sending an incorrect signal on where to locate resulting in charges that do not reflect the impact of connection on the network for DG.

The cause of this lack of cost reflectivity in charges comes from the fact that generation and demand are not treated equally by the current arrangements, so in treating DG as negative demand it is treated differently from other generators connected to the transmission system. Cost reflectivity is also impacted by the fact that demand charges in areas where demand is beneficial do not become negative (as they do in the generation charges). This means that DG connecting in areas where demand is beneficial still confers a benefit (of a small reduction in TNUoS charges) rather than a punitive charge.

Table 4-2 illustrates the impact of non-negative tariffs for demand TNUoS charges on the price signals sent to DG connecting in a location with an excess of transmission connected generation. If the demand tariff cannot be negative, then addition of DG into the system simply

reduces the demand charge, in this instance from £4,000 to £3,200. This provides a price signal which encourages connection and does not reflect the impact of DG at higher network levels. Allowing the demand TNUoS charge to be negative and paying demand in areas where it is beneficial means that the additional of DG has the opposite effect. In this instance, adding DG (still treating it as negative demand) reduces the net demand value and cuts the TNUoS payment proportionately.

Demand Zone 1 Northern Scotland	Tariff (£/kW)	Charge for 10 MW demand (£)	Charge + 2MW Gen @ Distribution (£)	Total Demand TNUoS (£)	Impact of DG
Current Charges (non-negative)	0.40	4,000	- 800	3,200	Positive: Reduction in **Charge**
Negative charging (illustrative charge)	-0.40	-4,000	800	-3,200	Negative: Reduction of **Payment**

Table 4-2: Illustration of the impact of negative and non-negative tariffs for demand TNUoS charges on cost reflectivity for connection of DG

As penetration of DG into the system increases there is a concern that these discrepancies caused by unequal treatment of generation and demand will become material resulting in transmission connected generation cross subsidising the impact of DG not captured by formal transmission arrangements. Furthermore, the lack of adequate locational signals for DG to site optimally within the network could lead to sub-optimal and inefficient network development, ultimately increasing the cost of power to end-users (Ofgem, 2005a, NGET, 2005a).

4.2.7 Implications of propagating the TEC-based approach to transmission access for distributed generation and demand

Given the shortcomings of the present arrangements, and the requirements for future transmission access arrangements, this section assesses the impact of applying the current TEC based investment and access arrangements to all generation embedded in the distribution network. It evaluates the potential problems that application of the TEC approach would bring to development of efficient investment and access arrangements and assesses the implications for development of an enduring cost reflective transmission pricing regime for DG.

Delivery of net characterisation of generation and demand

Optimal derivation of DG access requirements should be on the basis of a net consideration of all DG in a GSP, including the contribution of demand and considering fluctuations according to time of day rather than peak demand conditions. This is to take account of diversity in output of different distributed generation technologies and to recognise the equal and opposite impact of demand on the net flows at the transmission boundary. TEC in its current format is not

suitable for translation to the case of DG as it cannot take account of these subtleties in DG operation that are crucial for the recognition and reward of its value to the system, and crucially it does not extend to consideration of demand.

Demand access is calculated on the basis of metered consumption, rather than stated requirements (as is the case for transmission connected generation). There is currently no compatibility between the calculation and charging for demand and generation access requirements. To change this would require creation of a demand Transmission Exit Capacity (a stated preference of the maximum required capacity for drawing power from the transmission system), or alternatively an equivalent of the ex-post approach for demand could be devised for generation.

A cost reflective solution to this is unlikely to involve TEC in its current form, as this long term firm access product has been developed to facilitate calculation of network requirements according to the sum of peak generation output only. This is at odds with the optimal and cost reflective solution for net DG and demand transmission access arrangements.

Recognition of diversity and opportunity for sharing of capacity

Access to transmission for DG using a gross TEC-based approach would see individual distributed generators with separate arrangements for transmission access. Based on the current arrangements, this would resemble a system where all DG have an individual TEC (or BEGA arrangement) for firm transmission access rights. This approach has the potential to grossly overestimate the impact of DG at the transmission level and charge without regard to a cost reflective and fair solution.

Under the existing arrangements, providing DG with universal access to transmission, removing the embedded benefits reduction and exposing DG to generation (TEC based) charges for use of the system would not allow net consideration of the demand/generation balance. This would fail to recognise the value that can come from (correctly located) DG serving local loads and would simply change, but not resolve, the problems of distorted cost allocation with reference to DG driven transmission investment.

Transmission capacity is driven by net power flows at the transmission/distribution boundary, so it is appropriate that the contribution of both generation and demand should be considered. A fully cost reflective approach to enabling DG access to transmission should entail net treatment of DG within a particular geographic area, including the contribution of demand to recognise this diversity and facilitate sharing of transmission capacity between users.

Quantifying the impact of DG and demand on transmission

The generation system is a fundamental part of transmission system management. Increasing penetration of DG is changing the use of boundaries between transmission and distribution. The impact of this effect on transmission in terms of driving network investment, and allocating costs to system users is not clear. But, as numbers of DG connected at the distribution level increase further there will be a growing pressure to devolve system control responsibilities, and to enable DG to provide an increasing level of system operation services. To facilitate this activity requires DG to be visible at the transmission level, to have access to the transmission network, and for there to be a clear methodology on how much access DG requires and how this should be priced.

The current TEC methodology requires that generators state their maximum access requirements, and pay use-of-system charges according to this requested allocation. In the instance of generation and demand connected at distribution level, not only is their impact at transmission level dependent on the output and consumption of the surrounding distribution network users, but their individual contribution to the net flow at the transmission distribution boundary is dependent on the distribution network topology. All of these factors (generation output, demand and network conditions) are subject to continual change, so the complex interaction between all three that makes the net flow at the transmission boundary is also changing on a second by second basis, as a result of these interactions. As such, for a single generator in isolation to be able to state its long term requirements for transmission access in the form of a TEC request is an impossible simplification. Not only does the generator not have at its disposal the real time information about other generation and demand activity in the locality, it also has no information on the topology or real time changes in the distribution network that influence its contribution to the GSP boundary flows.

Indeed, only the Distribution Network Operator is likely to be able to quantify all these impacts, allocate a contribution to each generator or load in the network, and create a single profile for the TSO. From the perspective of propagating the current TEC-based transmission access arrangements to DG and demand, it is clear that this suffers similar shortcomings as for application to transmission connected with generation. The lack of a mechanism to facilitate sharing of capacity or to appreciate diversity in system users leads to fundamental inefficiencies, and the absence of any arrangements for short term access is a key barrier to the development of cost reflective charges for non-conventional generation.

4.2.8 Conclusions and implications of the evaluation

The range of gaps and inefficiencies explored in the evaluation make it clear that the present transmission arrangements do not create a cost reflective regulatory or market framework for systems with non-conventional generation. The TEC-based approach to access is not capable of reflecting differences in operating characteristics of generating technologies, or of accounting for diversity in output that might allow for sharing of capacity; the two key access requirements of non-conventional generation.

The presence of only long term access options tends to over-value network access in systems with non-conventional generation. It doesn't allow transparency of value in the short term, which disguises the fact that during most periods of normal operation the network is unconstrained and the value of access low (limited to the cost of losses). This absence of a short term market for access means that user choice of access products is limited, and mechanisms that might facilitate economic sharing of transmission capacity during congested periods are not possible.

The lack of comprehensive transmission arrangements for DG is potentially damaging for cost reflectivity and risks cross-subsidy between distributed and transmission connected generation. Transmission connected generation and demand customers are not treated equally by the current arrangements, and distributed generation is treated as negative demand, thus, there is a disparity in the treatment of all parties. Harmonisation of the transmission arrangements between distributed and transmission connected generation requires considerable reform of the existing arrangements. Moreover, representation of DG and demand at transmission level also presents a series of practical challenges on how to characterise and represent an aggregated group of resources in a manner which can be interpreted and utilised by the TSO.

The subsequent section develops a framework for the development of new access arrangements that respond to the gaps in the present structure as highlighted above. The following chapter (Chapter 5) responds to the final point in the summary which highlights the technical complications of aggregation, characterisation and representation of DG and demand at transmission level. Chapter 5 also addresses the challenge of developing a technical architecture to facilitate transmission access for DG and demand by developing and exploring the concept of the Virtual Power Plant.

4.3 Framework for universal arrangements for transmission access

The following section proposes a framework to allow analysis and discussion of the development of new enduring regulatory and market arrangements for transmission access with universal applicability (i.e. to transmission and distribution connected generation and demand). To initiate the process the first section is used to identify a series of high level criteria that characterise optimal, efficient and cost reflective transmission access arrangements. These criteria are then used as a metric against which proposals for enduring arrangements can be tested.

The subsequent section then generates three options for new transmission arrangements. The first represents an incremental improvement on the current arrangements as described and evaluated in the previous chapters (i.e. an approach with an absence of locational signals for the value of short term transmission access). The second option maintains the lack of any short term access arrangements, but includes a step change in investment and access philosophy. The third and final option is to create markets for short term access. This represents a fundamental shift in philosophy and method with the development of an ex-post market for short term transmission access. Each of these options is elaborated further and analysed against the high-level criteria to determine their likely contribution to the development of optimal and efficient access arrangements.

4.3.1 Requirements for future transmission arrangements

Under the current framework, the System Operator must demonstrate the requirement for transmission investment in additional capacity for approval by the Regulator. Justification of investment should be made using a robust methodology that determines the need for reinforcement according to the impact of all users (generation and demand) on the system. The following outlines the key requirements for a generic methodology to determine the need for transmission investment.

There are numerous core criteria that should be considered in the development of enduring and efficient arrangements for any future transmission arrangements. These are the factors required to create efficient cost reflective arrangements that conform to fundamental market principals and provide a level playing field for all system users including non-conventional generation and demand. The criteria have been developed from the extensive analysis and evaluation carried out in the previous chapters, and represent the requirements of a future system which features a mix of conventional and non-conventional (renewable and distributed generation). These high-level criteria which characterise optimal arrangements are:

- Cost reflectivity to facilitate competition in generation and supply,
- User choice in utilisation of access,
- Reflection of differences in generation characteristics and inclusion of demand,
- Representation of location and time of use,
- Sharing of access between system users,
- Continuity between short and long term value of transmission, and
- Flexibility to deal with uncertainty in future generation development.

Cost reflectivity to facilitate competition in generation and supply

In the context of electrical power systems, cost reflectivity is concerned with sending price signals to individual users with respect to the costs they impose on network operation and/or development. This will ensure that in the short term, the system is efficiently operated without cross-subsidy between users and that, in the long term, it follows the path of least cost development (efficient investment). Regarding network operation and expansion, this requires some form of coordination between generation and network development as the optimisation of the network in isolation from generation would almost certainly not meet the above objective. Historically, vertical integration of conventional utilities seemed necessary for a sufficient level of coordination to be achieved. In the competitive environment, the necessary coordination of investing in generation and network assets is to be achieved through efficient network pricing mechanisms.

User choice in purchase of access

In future systems, transmission network capacity should be shared amongst various generating technologies and hence the network will be occasionally constrained. Users competing for this shared capacity will need the opportunity to exercise a choice between exposure to the short term cost of access (during the periods of constrained operation) versus purchasing a known-price firm-access product and paying use of system charges. To allow this choice an ex-post short term market for access is required to reveal the value of transmission in real time. Within the present charging framework this cannot be achieved as this only considers long term access or no access at all.

Reflection of differences in generation characteristics and inclusion of demand

To achieve cost reflectivity and provide choice, commercial and regulatory arrangements must be designed to recognise and reflect different generation characteristics between technologies. In the past, the generation mix has been dominated by large-scale centralised generation that has allowed generalisation and the development of generic arrangements to suit one technology type. Future systems are likely to be composed of many different generating technologies, for

which generic arrangements are no longer suitable as they fail to recognise the unique parameters that dictate the demand for transmission capacity imposed by new generation Failure to differentiate between generation technologies is discriminatory against new, non-conventional generation.

The recognition and inclusion of demand in any arrangements is also of critical importance. Demand has an equal but opposite impact on the system as generation, so the access requirements of demand are a potential resource that can be released by effective market arrangements. Although, historically, demand has had little engagement with the market and is perceived to be relatively inelastic, in future scenarios with significant penetration of wind power the differential in cost of access across the system could be significant, and the driver for demand to participate may increase. To allow this response and participation it is important that new enduring arrangements complete the market and allow demand to make a contribution to optimal development and operation of the transmission network.

Representation of location and time of use

The impact of generation on the system is also governed by its location on the system and the timing of output. For conventional generation this output is generally predictable, and coincident with system peak. For intermittent, inflexible technology such as wind, its location on the system and its timing of use of the system is less predictable. To capture the real impact of wind on the system requires a framework able to distinguish location and time of use of the system throughout the day, and design network investment and related charging structures accordingly.

Sharing of access between system users

If consideration of location and time of use of the system is made for all generation (and demand), then account can be taken for the same transmission resource being used by different generators at different times. Economically optimal access arrangements will evaluate the cost of constraints against the cost of building new transmission to meet the peak capacity requirements of all users in a constrained area. Where constraint costs are low, and in locations with diversity of generation technologies and demand, the resulting diversity in output will permit economic sharing of capacity, which should be reflected in any new transmission arrangements.

Continuity between short term and long term costs

The short term value of transmission access capacity is derived from the costs of balancing system constraints caused by insufficient transmission capacity to allow the fulfilment of energy

contracts between generation and demand in different locations across the system. Long term value of transmission is driven by the requirement for network reinforcement and the need for additional investment in capacity to counteraction network constraints. The long and short term value of transmission is linked such that consistently high value of transmission in the short term should translate to activity in the long term to invest and build additional capacity.

Conversely, construction of transmission infrastructure as part of a long term investment strategy should also impact the short term value of transmission, for example, investment in network reinforcement in a heavily congested area should lower the short term value of transmission by reducing constraints.

Because there is continuity between long and short term value of transmission, revealing the short term value of transmission is a key aspect of providing additional evidence on the need for transmission investment, and indicating the cost effectiveness of sharing transmission between system users. Additionally, consider the short term value of transmission for intermittent and highly variable generation. Short term access is highly relevant to these system users as their usage of capacity and impact on the system is difficult to quantify accurately away from real time. Take the example of wind generation which can only accurately forecast its output (and transmission access requirements) very close to real time (i.e. intra-day, less than 4 hours ahead of real-time). A long term access product is relatively meaningless in terms of signalling the actual capacity requirements of these technologies.

Flexibility to deal with uncertainty in future generation development

There is currently 16GW of onshore and 8GW of offshore wind with outstanding applications for connection to the GB transmission system. The exact materiality of all these applications is unknown; experience would suggest that only a proportion of the applications for connection will result in connection of new generation (because of for example, rejection of planning permission or loss of investment backing). The exact amount of new generating capacity that will make it on to the GB system in the short term is uncertain, and as the planned connections exceed all previous historical developments, there is little experience to draw on to determine a likely outcome. In addition to this new generation uncertainty, there is a similar level of uncertainty on the side of retirement and decommissioning of existing plant. Together, these two factors place several GW of uncertainty on development of the future system over the coming few years.

Any new arrangements developed for the evolving system will have to take into account not only the different generating characteristics of new technologies, and the locational and

temporal aspects of generation – but also the fact that the exact nature of the generation mix (and demand landscape) is subject to some considerable uncertainty. For the development of enduring transmission arrangements it is therefore desirable that they are sufficiently flexible to allow any future uncertainty to be factored into the approach without compromising cost reflectivity.

4.4 Comparative framework for assessment of future transmission access arrangements

Three broad options for development of transmission access arrangements for system with significant penetration of DG and renewables were introduced in the previous section and are illustrated in Figure 4-2[34].

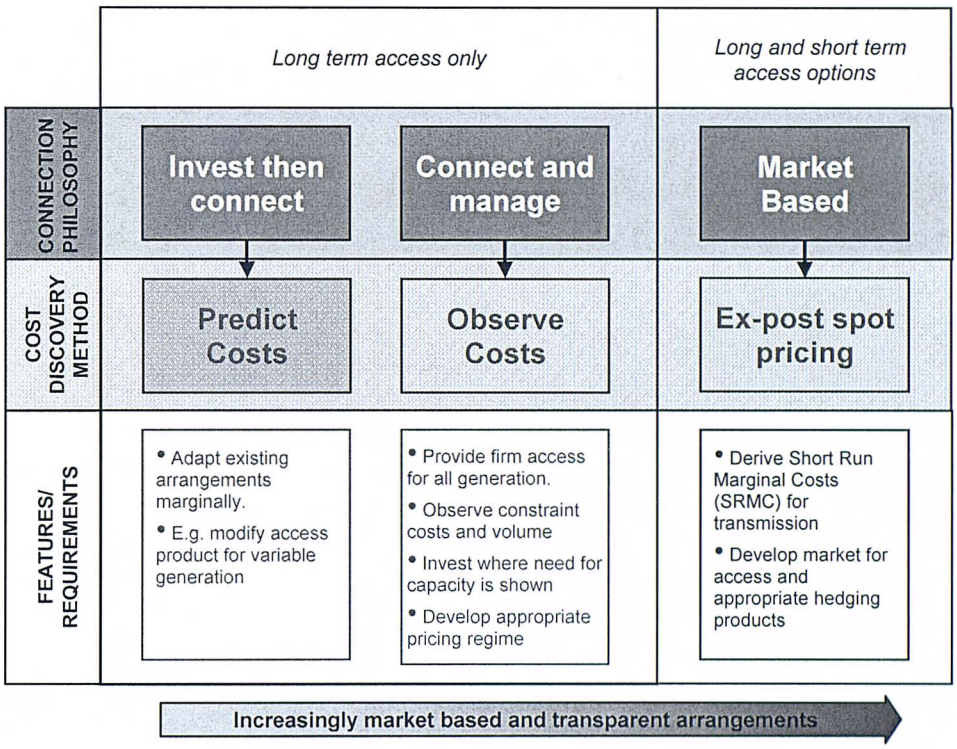


Figure 4-2: Options for future transmission access arrangements

Each option represents a different philosophy and method for allocation of access, and they have been devised to facilitate discussion of the relative merits of a pricing policy based on short term ex-post market derived values, versus a long term investment based approach, grounded in a prediction based planning approach to network operation and development. The characteristics of each option are laid out below, followed by an analysis with reference to the high level criteria and discussion of the implications of implementation.

[34] Although it may be possible to derive different variations and combinations of the options analysed, these are not elaborated further given the objective and scope of this thesis.

Invest then connect: Incremental change to status quo access arrangements

This option ("invest then connect" philosophy, predict costs) is grounded in the present arrangements, predicting all future market developments and investment requirements through forecasting and system modelling. The impact of users on the system is modelled using deterministic, stochastic and/or heuristic rules, and system users give a limited indication of the impact they have on the system (through TEC). This philosophy is suited to an "invest then connect" method and is broadly in line with the current GB arrangements. Where it differs from the present arrangements is through an improved planning process which quantifies the different impact of individual users with a greater level of accuracy.

Connect and Manage: New cost discovery method for status quo access arrangements

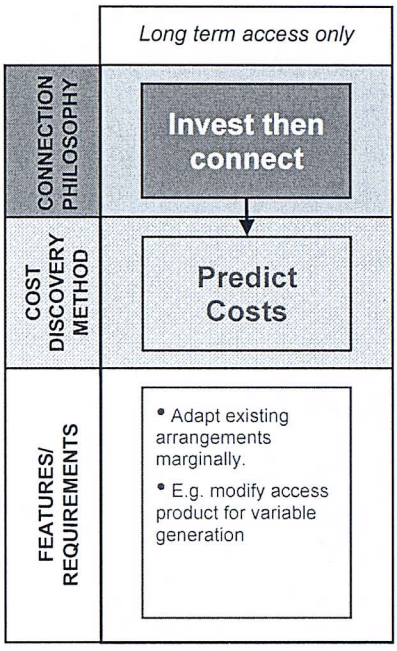
Although the focus on long term investment based charging for access remains, this option ("connect and manage" philosophy, observe costs) has moved to the "connect and manage" approach to system reinforcement. All generation is connected to the system and given 100% firm access to accommodate all output. The System Operator observes system constraint costs and volumes caused by users activity on the system, and acts on trends in costs to stimulate long term investment where high constraint costs signal that it would be economically optimal. There is increased transparency in the derivation of the short term value of transmission and the need for long term investment, but constraint costs are socialised and system users are not exposed to the full costs of their actions.

Market based: Fundamental reform of access to introduce short term value of access

This option (market based philosophy, ex-post spot pricing) is a departure from the current approach, and a development of the competitive market based approach to access. The final option involves determination of short term prices for access to transmission via an ex-post competitive market for access. Under this philosophy the value of access is determined by the market and system users; both generators and demand can make appropriate choices when valuing transmission in the short and long term and can balance their position accordingly. These market derived prices also provide evidence of need for additional capacity if network reinforcement is required.

To explore the possibilities for development of appropriate transmission arrangements for future sustainable energy systems, these three approaches to transmission access are compared against the requirements for new arrangements laid out in the previous section.

4.4.1 Invest then connect & predict costs



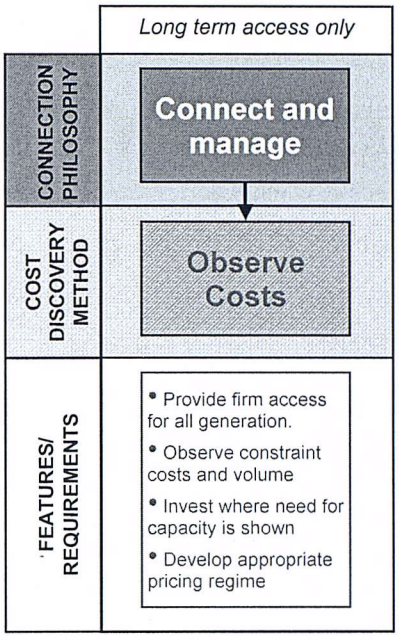
The "invest then connect" philosophy is broadly in line with the current GB arrangements. Under this approach, all future market developments and investment requirements are predicted through forecasting users' need for transmission over the long term (ideally covering the life span of the transmission assets) including the user's commitment to connect through purchase of TEC. Under this option the status quo approach is marginally improved through a development of the planning process which quantifies the different impact of individual users on the demand for transmission capacity with a greater level of accuracy[35].

However, there is uncertainty over how much TEC individual system users should purchase (specifically non-conventional generators with an output profile and use of the system that does not correlate to peak network conditions). This is a particular problem in areas with a mix of conventional and non-conventional generation such as wind, where the opportunity for sharing of transmission is at its greatest. Practically, development of the "invest then connect" approach to reflect this would require a more transparent process to be established between the amount of TEC issued and the actual transmission capacity required to support it. This relationship is not clear at present, particularly when considering non-conventional generation.

Where economically optimal, sharing of transmission capacity is desirable, but as discussed in Chapter 4 the fixed TEC product is incapable of delivering this outcome. The restrictive nature of TEC means that differences in location and time of use of the system for different system users cannot be taken into account with any accuracy. In addition, limitation of access products to only TEC does not provide sufficient choice for participants. Most new generation projects require a guarantee of firm access to secure investment backing. As there is no alternative to TEC, and access is a pre-requisite for financial support, all new schemes must purchase a long term access product, regardless of its appropriateness for their needs. Development of alternatives to TEC such as products offering firm access over a range of timescales (from intra-day to long term access to transmission) could offer more choice to developers and investors, whilst still providing an assurance of access. This could be delivered through the "invest then connect" approach.

[35] For further elaboration of the planning process and format of the current standards for design of transmission networks see Chapter 2.

4.4.2 Connect and manage and observe system costs



The philosophy of observing network constraint costs and volumes is linked to the "connect and manage" method of system operation and investment. This method allows connection of all new entrants to the system prior to reinforcement. Investment in new transmission is then made by observation of actual trends in system constraint costs and volumes, and construction of new infrastructure is then undertaken with an understanding of where observed constraint costs indicate that it is (economically) optimal to do so. This approach implicitly allows the sharing of capacity between generation technologies with a diverse use of the system, and provides a more transparent view of the criteria for system expansion and reinforcement.

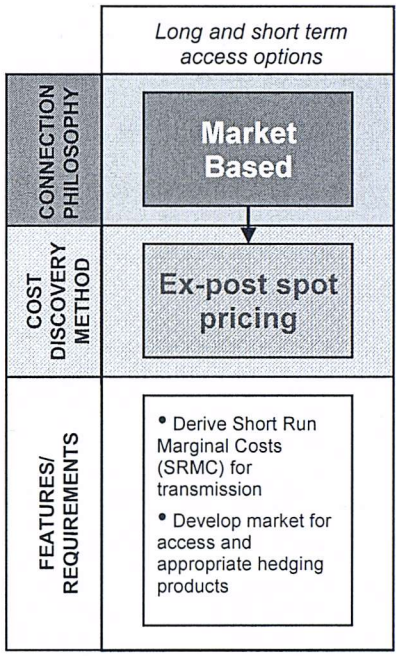
In the "connect and manage" system constraint costs caused by users' activity on the system will be monitored and observed, and the system operator will act on trends in costs to stimulate long term investment where it is economically optimal. Under this approach there is increased transparency in the derivation of the short term value of transmission and the need for long term investment, but constraint costs are socialised and system users are not exposed to the full costs of their actions. There is an increased transparency of the process in determining the need for additional capacity, however there is the danger that under this approach, without timely investment in reinforcement, constraint costs could escalate and remain high for unacceptably long periods.

Under this regime, TNUoS charges and system security standards could be updated to reflect the new "connect and manage" approach and to recognise the influx of non-conventional generation. TEC is no longer required as all generation is given full access at all times. Participants would be charged according to their actual use of the system, i.e proportionally to the capacity their connection drives. Transmission investment proposals are still made by National Grid and approved via the Regulator; however, this activity is now justified via the observed constrained costs in the system, rather than on forecasts of future network conditions. Under this method, the System Operator has an appreciation of the short and long term value of transmission in different locations across the network that can assist in development of an optimal investment strategy. However, the pricing signals provided to users of the system will be similar to the present arrangements; locational TNUoS signals will indicate the long term

costs of using the system (albeit with a new cost reflective methodology), and short term BSUoS charges socialised across system users.

In the process of developing enduring market based transmission access arrangements, the "connect and manage" option can possibly serve as an interim solution but further work is required to examine such proposition quantitatively.

4.4.3 Competitive Market Philosophy: Ex-post spot pricing



The alternative to the above market proxy solutions is to pass transmission investment decisions over to competitive markets and use cost reflective locational access price signals to indicate to users their impact on the system and guide optimal development of the network. According to this philosophy, capacity investment, expansion and access is all coordinated by the establishment of an ex-post short term market for access that is driven entirely through efficient short term market signals, e.g. Locational Marginal Pricing (LMP)[36]. As highlighted previously, under BETTA there is a separation of energy from access, such that energy can be bought and sold anywhere in the network without consideration for locational constraints. To maintain this separation of energy and access requires the establishment of a spot market for access. The development of a separate market maintains the overarching structure of BETTA and does not disrupt the energy markets, but it removes the requirement for prediction or observation of the need for transmission investment and access putting users of the network in the centre of the investment decision making process.

Deriving the short run marginal cost of transmission access[37]

As discussed earlier, the key requirement for achieving efficient investment in a system with significant penetration of wind power is an understanding of not only the cost but also the value of transmission in both the short and long term. To achieve this requires the creation of an ex-post (overrun) short term market for access. From this ex-post spot-price for access, the market participants (including the system operator) can derive appropriate hedging products (for example, trading or auctions of access rights over various time horizons that allow them to

[36] The LMP model is implemented, among a number of jurisdictions, in the Nord Pool (www.nordpool.com) which calculates zonal prices and in the largest Electricity Pool in the world, Pennsylvania, Jersey and Maryland (PJM), where ex-post LMPs for more than 50,000 busbars are calculated every 5 min (www.pjm.com).

[37] This discussion of the SRMC is based only around the impact of constraint costs. It excludes consideration of losses. Consideration of the impact of losses is an area for further work.

balance their position ahead of real time (as is the case in the wholesale electricity market)[38]. Given that the change in access arrangements is driven by the need to integrate wind power cost effectively, and bearing in mind the variability of wind power over short term time horizons, it is essential that trading includes half hourly resolution (as seen in the wholesale electricity market)[39]. Moreover, it is essential that system users always have the option to overrun and pay the ex-post short term access price that reflects the marginal costs of resolving the constraint caused by the overrun. This ex-post (overrun) price is the key for establishing the value of any ex-ante hedging contract and ultimately the value of existing and future transmission investment[40].

To generate a market for access requires derivation of a spot price for access, i.e. pricing based on the short run marginal costs (SRMC) of transmission. These prices are implicit within the LMP calculation which determines the cost of energy including the locational element. To derive the short run costs of access separate from the energy costs requires the decomposition of this LMP calculation into its component parts whereby:

$$SRMC\ transmission = LMP - Reference\ Energy\ Price^{41}$$

The derivation of a short term marginal cost for access from the LMP price illustrates that, in principle, it should be possible to mimic LMP locational price signals in the British model, whilst maintaining the separation of energy and access.

Development of alternative access products and hedging short term risk

Identification of the short term value of access should highlight that under non-peak network conditions additional transmission access can be facilitated at very low (close to zero) marginal cost. During congested periods, the SRMC of transmission will reflect the value of the network. Network users exposed to SRMC will be able to balance their exposure between the short term and longer term through consideration of hedging facilities, contract trading and actions of access and investment. Where constraint costs are consistently high, and the SRMC of

[38] It is important to note that establishment of an effective ex-post short term access market is the key factor in achieving efficient and optimal enduring arrangements; trading of access (or auctions) and development of long term hedging products is of secondary importance as none of this is possible without the derivation of a spot price.

[39] Attempting to draw parallels between the transmission accesses arrangements for gas and electricity may not be appropriate. Trading arrangements limited to months or weeks ahead, as seen in the gas arrangements, are not appropriate in an electricity system with a significant penetration of wind power (characterised by unpredictable short term variability in output).

[40] In an over-invested transmission network, the network will be unconstrained for a significant proportion of time and hence the short term value of access may be very low. Where constraints are prolonged and corresponding costs are consistently high, with the short term marginal costs of transmission being greater than the marginal cost of transmission reinforcement, this should signal the requirement for long-term investment in new capacity.

[41] This decomposition of the LMP can be derived from SCHWEPPE, F., CARAMINIS, M., TABORS, R. & BOHN, R. (1988) *Spot Pricing of Electricity,* Massachusetts, USA, Kulwer Academic Publishers. This approach to derivation of the SRMC of transmission access was also taken in ILEX (2002) Transmission Access: Defining Alternative Models. Ilex Energy.

transmission is greater than the marginal cost of transmission reinforcement this should signal the requirement for long term investment in new capacity. In the context of developing a spot market for access, it may also be desirable to consider the principles behind the LMP approach. Under the LMP market model (which combines energy and access), positions are hedged using the point-to-point Financial Transmission Right (FTR). The FTR is a purely financial instrument that pays a rent to the FTR owner that is equal to the nodal price differential multiplied by the amount of capacity bought over the course of the contract (which can be any duration from hours to years).

In the access-only market described here there are parallels between the physical access rights afforded through TEC products and the FTR instrument. To mirror the FTR approach, the TEC market product must be adapted to facilitate its purchase (trading) over a range of timescales. In the case of wind, short term intra-day hedging products derived from TEC will be required to manage risk close to real time. Hedging products for wind outside of a few hours ahead of real time are relatively useless as the accuracy of forecasts for output reduces significantly rendering any medium to long term hedge inefficient and sub-optimal. This suggests that the wholesale electricity and access markets should operate with the same resolution.

Further analysis is required to explore the financial and physical approaches to hedging access positions in the competitive market, and to understand how TEC (as a physical transmission right) can be adapted to the competitive market for access. Creation of markets for access also raises questions of property rights for access that arise from physical transmission rights, held by incumbent generators with existing TEC.

Implications of market based access arrangements for demand

Currently, demand and generation are treated differently by TNUoS. There is no TEC equivalent (i.e. Transmission *Exit* Capacity) for demand, so whilst generators pay transmission charges on the basis of their TEC allowance (i.e. their maximum stated access requirements), demand is charged for access on the basis of its use of the system during the Triad (system peak). The total revenue generated through the TNUoS charge is recovered in skewed proportions, with 27% of the total TNUoS revenue coming from generators and 73% from demand. The BSUoS charge is shared equally amongst all system users, proportional to volumes each user has traded on the electricity markets. Under these arrangements, demand has little presence or influence on transmission system development. Demand is fixed by system arrangements as inflexible and unresponsive, as it has little or no opportunity to respond to price signals or the short term value of transmission.

In exporting areas that are subject to transmission constraints and where the value of transmission is high, the value of energy from zero marginal cost generation (i.e. wind) will drop to low values that could be materially different from other locations in the system (EAEA, 2007)[42]. Generators in these areas may need to pay a high price for transmission access to export energy. Conversely, demand within an exporting area should receive payment for accessing the network, as their use of the system reduces transmission constraints. Increasing demand in such areas can release transmission capacity, which will have value to generators in the same location wishing to export more. In instances of high price transmission constraints (and low price energy in constrained exporting areas) it would be beneficial for the system if flexible loads could respond to these signals and increase demand during these times.

With fully locational price signals and a difference in energy price (and the value of transmission) between constrained areas that is potentially material, demand should be able to respond to these prices in both the long and short term. In the short term, demand response and load shifting could take advantage of price signals and relieve local constraints. Whilst in the longer-term, opportunities for fuel switching could be material. For example, using electricity for space heating; if the price drops low enough electricity could displace gas which would have been otherwise burned, for example in industrial processes or for space heating. Furthermore, if economically optimal, this demand side fuel switching could also displace the need for transmission investment.

The current market carries the demand side as a silent participant. The transmission arrangements for investment, access and pricing are designed to make decisions on network expansion based on the assumption that demand is in the majority inflexible and inelastic. Arrangements have been developed that prevent demand side participation even when prices could potentially be influential enough to stimulate both short and long term demand response. The demand side has the potential to compete for the provision of transmission solutions and access, but this can only be achieved through full inclusion of demand within transmission arrangements. This should expose demand to these price signals to provide a basic platform and stimulus for demand participation. The case for including (or excluding) the demand side still needs to be presented and further analysis is required to determine the materiality of demand side participation of this nature.

Under the two methods based on market proxy arrangements for transmission access ("invest then connect" and "connect and manage") there is little impact on the potential for demand side

[42] Recent projections undertaken by EA Energy Analyses on 50% wind penetration in the Danish system have highlighted this feature that on windy days the price of wind power will drop to zero or near zero.

participation in response to transmission constraints and increased value of transmission. Under these two methods it is possible the maintain the current treatment of demand, whereby it is not exposed to locational price signals on the value of transmission and so not incentivised to react by load shifting or fuel switching. Moving on from the two market proxy arrangements, a spot market for access would necessitate a re-evaluation of the manner in which demand gains access to transmission and the method by which it is charged for its impact on the system. The locational BSUoS approach that is the result of a spot market for access necessitates the equal treatment of demand and generation. This recognises that demand and generation have equal but opposite impacts on the requirement for access, and should be charged accordingly. Under the market for access method, demand would also have to participate in the market to the same level as generation, i.e. participation in the spot-market and purchasing of hedging products to mitigate risk of exposure to volatile short term prices.

This approach would expose demand to locational signals on the value of access, and may facilitate the long and short term demand participation activity as outlined previously. It is the only option that facilitates exposure of all system users to costs which are reflective of their impact on the system and allows evaluation of the potential actions of all users to find the optimal solution for system development.

4.5 Summary of options for future transmission arrangements

Table 4-3 below compares the market approach with the "invest and connect" and "connect and manage" approaches through assessment of each against the requirements for achieving efficient system operation and investment. The table lists each of the options against the requirements for optimal system development as identified in section 4.3.1.

The overarching metric against which these arrangements are measured is the contribution they make towards cost reflectivity and accurate representation of the impact of individual users on the system. The table exposes that full cost reflectivity is only achieved through the market for access approach. The "invest then connect" approach which maintains TEC as a means for allocating capacity is not capable of generating cost reflective charges in systems with significant penetration of non-conventional generation. Whilst the "connect and manage" approach does allow National Grid and the regulator to observe the real costs of the system and make appropriate investment decisions, these costs are not systematically passed on to users. National Grid determines how the system will respond to these costs and makes investment decisions accordingly, using the observed trends in constraint costs and volumes to justify network expansion to the Regulator. The allocation of costs in this instance requires further

analysis to understand how revenue flows of all parties will be affected and whether this can be justified against savings in energy costs.

Philosophy & Method	Predict costs	Observe costs	Competitive market
Requirement	*Invest then connect*	*Connect and manage*	*Ex-post market for access*
Cost reflectivity	Not cost reflective, absence of link between TEC and TNUoS charge	Proxy for long term cost reflectivity from observed constraint costs. No signal for short term costs	Cost reflective, provided efficient (ex-post) SRMC for access can be established
Access choice	Only long term access	Not applicable	Full choice between no access (i.e. ex-post real time pricing) and long term firm access
Reflection of differences in generation characteristics and inclusion of demand	Limited ability of TEC to discriminate between generation technologies reduces opportunity to reflect differences accurately. Arrangements favour conventional generation and exclude demand	Identification (through observation) and incorporation of specific technology characteristics into arrangements is required, but still does not allow full inclusion of demand	Different generation characteristics and demand implicitly included in market approach (provided appropriate market products are devised to support activity)
Representation of location and time of use (TOU)	No short term market, TEC inherently unable to establish link between TOU and impact on investment. Too inflexible. Long term locational signals from TNUoS charges	TSO observes impact of short term locational and temporal variations in use, but this is not signalled to users. Long term locational signals from TNUoS charges	Location specific SRMC of transmission published half hourly, equivalent to locational BSUoS charge.
Allow sharing of capacity	No sharing of capacity possible	The managed approach facilitates sharing of capacity	Sharing of capacity implicitly included in market approach
Continuity between long and short term value of transmission	No direct/transparent link between long and short term value, both are based on TSO prediction of user requirement	Increased transparency on link between long and short term value as TSO and regulator observe short term costs	Correct market design should allow continuity between long and short term value
Able to deal with uncertainty in generation development	No, inflexible approach makes it difficult to respond to unpredicted changes in generation development	Yes, to an extent. Connect and manage allows some responsiveness. But some market proxy arrangements are still inflexible to change	Yes, dealing with uncertainty in generation development is implicit in a market approach

Table 4-3: Summary table of future options for developing transmission investment, access and pricing arrangements against identified requirements for optimal system development.

The TEC based approach does not offer sufficient choice in access (generators without long term access cannot generate), hence it does not allow sharing of capacity and cannot

differentiate between generation types and maintains the current situation of excluding demand from having an active role in the transmission investment and access framework.

The opportunity for sharing of transmission between different generating technologies and demand is also necessary for the optimal development of transmission access requirements. Under the "invest then connect" approach, sharing of capacity is not possible. TEC prevents cost effective development of transmission, leading to over- or under- development of the network because it is too inflexible to guide transmission investment on the basis of diverse requirements for access, balanced against constraint costs and the marginal cost of investment in new capacity. The "connect and manage" method allows 100% access to all system users at any time; this inherently facilitates sharing of capacity, although demand is not necessarily included in these arrangements. Under this approach, where extreme constraint costs are experienced, this should be observed by National Grid and used as evidence for reinforcement of the network to alleviate the constraint. The market for access also operates the same implicit approach to sharing of transmission, although under this method demand is also fully included in the market, treated in the same way as generation and enabled to respond to the changing value of transmission access.

Achieving continuity between the long and short term value of transmission is a balancing act to optimise long and short term costs. High value of transmission in the short term, in constrained areas, should indicate the need for transmission investment and reinforcement. Demonstration of the link between the long and short term value of transmission is required to justify action on building capacity, particularly when transmission is treated as a monopoly function. The "invest then connect" approach is based on the philosophy of predicting future network development and user impact on the network. The case for investment is then made as a derivation of these forecasts (subject to uncertainty of future outcomes and the assumptions made in their development). A stronger case for the justification of investment is made by the alternative approaches that might still use an element of the forecasting technique, but also base infrastructure investment on observed constraint costs ("connect and manage") and on market derived spot prices for transmission access (market for access).

This leads into the final requirement for optimal future transmission arrangements, which is the ability to deal with uncertainty in future generation development. As highlighted previously, the "invest then connect" method predicts a future scenario for generation development (and demand, generation retirement etc.) and bases all arrangements around this forecast. The alternative options are both grounded in responding to the real time requirements of the system,

so both are better placed to become enduring arrangements, able to incorporate uncertainty in system developments without the loss of cost-reflectivity.

4.6 Conclusions on options for new enduring access arrangements

This framework for enduring transmission access arrangements supports the case that the present regulatory arrangements for transmission investment, access and pricing do not produce a supportive environment which reflects the fundamental economics of systems with wind and conventional generation; under the framework this thesis sets out the high level requirements for enduring transmission access arrangements and develops a method and philosophy for enduring transmission access that would deliver efficient transmission infrastructure investment for a sustainable system.

This framework uses a number of core criteria that should be considered in the development of enduring transmission arrangements: (i) cost reflectivity, (ii) availability of choice in access arrangements, (iii) reflection of differences in generation characteristics, (iv) representation of location and time of use, (v) sharing of access between generation technologies, (vi) continuity between short and long term value of transmission and (vii) flexibility to deal with increased uncertainty in future generation development. These are the factors required to create effective and efficient arrangements that conform to the fundamental economics of a system with a high penetration of wind generation and provide a level playing field for all system users including demand. These criteria were used to demonstrate the key advantages of a market-based approach to access using ex-post, short-run transmission access pricing. The strengths of this market approach are identified through comparison against the present "invest and connect" approach and the proposed "connect and manage" philosophy.

The analysis strongly emphasises that the key requirement for achieving efficient investment in a system with significant penetration of wind power is an understanding of not only the cost but also the value of transmission in both the short and long term. To achieve this requires the creation of an ex-post (overrun) short term market for access. From this ex-post spot-price for access, the market participants (including the system operator) can derive appropriate hedging products e.g. trading / auctions of access rights over various time horizons that allow them to balance their position ahead of real time (as is the case in the wholesale electricity market)[43]. Given that the change in access arrangements is driven by the need to integrate wind power cost effectively, and having in mind the variability of wind power over short term time horizons, it is

[43] It is important to note that establishment of an effective ex-post short term access market is the key factor in achieving efficient and optimal enduring arrangements; trading of access (or auctions) and development of long term hedging products is of secondary importance as none of this is possible without the derivation of a spot price.

essential that trading includes half hourly resolution (as seen in the wholesale electricity market). Furthermore, it is essential that system users always have the option to overrun and pay the ex-post short term access price that reflects the marginal costs of resolving the constraint caused by the overrun. This ex-post (overrun) price is the key for establishing the value of any ex-ante hedging contract and ultimately the value of existing and future transmission investment[44].

In systems with significant penetration of wind energy, the value of access for generation in highly export-constrained areas (e.g. Scotland) will increase. Under a location specific approach for pricing short term access, this will lead to a reduction in energy prices in these areas, particularly during periods of significant wind generation output, i.e. on windy days. This effect is already being predicted in Denmark if penetrations of wind generation continue to increase (EAEA, 2007). There is the potential for prices to drop to the extent that previously latent demand response may be activated, increasing demand for the cheap electricity and possibly displacing gas which would have been otherwise burned (e.g. in industrial processes or for space heating). In the longer term, if economically optimal, this demand side fuel switching could also displace the need for transmission investment[45].

In summary, in order to solve the long term transmission investment problem and to facilitate cost effective integration of wind energy in the UK, there is a need for a radical shift in the approach to transmission access pricing from long term investment based network pricing to ex-post short term network access pricing; part of the radical change should also include the incorporation of demand in access arrangements[46].

[44] In an over-invested transmission network, the network will be unconstrained for a significant proportion of time and hence the short term value of access may be very low. Where constraints are prolonged and corresponding costs are consistently high, with the short term marginal costs of transmission being greater than the marginal cost of transmission reinforcement, this should signal the requirement for long-term investment in new capacity.

[45] In Denmark for example, there are significant initiatives (e.g. EcoGrid) to increase demand side participation to manage cross-border transmission access and instead of exporting wind energy on windy days to Norway at zero marginal price, to use this electricity to displace usage of gas, see www.energinet.dk and the EocGrid project microsite: www.ecogrid.dk.

[46] This analysis also raises important questions on the roles played by various owners and operators on the system. Although out of the scope of the present discussion, further work could include consideration of the roles of the system operator versus transmission owners, and explore the role of the independent system operator (ISO), and whether the connection between TO and SO is a valuable one still relevant in the developing marketplace.

CHAPTER 5: Technical architecture to facilitate transmission access for DG and demand

5.1 Introduction

The arrangements described in the previous chapter accommodate the transmission access requirements of DG and demand by allowing representation of the characteristic requirements of these system users (sharing of capacity, recognition of diversity, equal treatment of demand and generation etc). However, the application of this new framework to DG and demand for exposure to transmission arrangements brings a logistical challenge with the issue of managing the involvement of thousands (potentially millions) of small network users. There is also the practical challenge of how to characterise and utilise these distributed resources that are autonomous users of the network, but have an impact at transmission level that must be represented as part of a net calculation of generation, demand and network conditions. The practical concerns can be distinguished under the following headings: aggregation, characterisation and functionality, and representation.

i) **Aggregation:** Most DG and demand units are too small to be considered as significant or useful at transmission level. As individuals they have little physical impact of note, so utilisation of their services is not practical or helpful. To gain presence and recognition at transmission level, users connected to the distribution network must be aggregated into portfolios that have a combined output and impact of more significant magnitude.

ii) **Characterisation and functionality:** Determining the individual and collective impact of DG and demand on the transmission network requires new approaches in characterisation. Designation of the impact of an individual unit on the net flows at the GSP varies with time, and with the changing parameters of other generators, demand and the network. Portrayal of a portfolio of resources in terms that will be useful to the TSO is the first task, followed by decomposition of the aggregated profile into composite parts to indicate to the participants their role and responsibility and charge (or reward) accordingly.

iii) **Representation:** There are hundreds of thousands, and potentially millions of users in the distribution network who could be exposed in some way to the transmission access arrangements described and allowed to participate in activities at transmission level. Realistically, if the level of transmission access is devolved right down to the low voltage level of the distribution network, there will be physically too many participants and interactions for the TSO to form individual contracts and interactions with each and everyone (notwithstanding the initial problem that as individuals, units in the distribution network hold very little interest or impact for the TSO). To allow the TSO to take advantage of these resources requires a third party agent/aggregator role to characterise and quantify the output of a group of resources.

One proposal to address these practical issues is the development of Virtual Power Plant (VPP) structures which would allow the aggregation of a large number of distributed resources into a single profile which resembled the output and characteristics of a transmission connected generator. The following section explores the VPP options for aggregation, characterisation and representation of these resources. By analysing the development of the VPP concept the chapter explores how transmission access can be realised for DG, both to offer system services, and accurately calculate the impact of DG on the higher level networks. The VPP aggregation concept also raises opportunities for portfolio control to allow controlled and optimal interfacing of distributed resources with the energy and ancillary services markets. The characterisation explores the development of integration achieved through inclusion of demand and application of advanced ICT.

5.2 The Virtual Power Plant

The potential use of the VPP concept has been recognised in a number of recent publications and explored in several ongoing research projects[47]. Early identification of the concept of virtual collections of distributed resources can be found in (Awerbuch and Preston, 1997). This contribution describes the advance of distributed generation coupled with changes in the commercial and regulatory structure of liberalising electricity industries have created opportunities for devolution of transmission access to lower levels of the network. In 1997 (Awerbuch et al., 1997) proposed that these factors would result in the emergence of numerous, smaller and leaner organisations able to take advantage of the benefits of distributed energy resources managed in a VPP-like configuration.

[47] E.g. Two European Commission funded research and demonstration projects; Flexible Electricity Networks to Integrate the eXpected energy evolution (FENIX), www.fenix-project.org , and distributed intelligence in CRitical Infrastructures for Sustainable Power (CRISP), www.ecn.nl/crisp.

Since then, significant developments in information and communication technologies have led to new forms of DG control and electricity market interfaces (Gregerson and Mariyappan, 2001). Sophisticated ICT architectures have been proposed to cope with the increasing complexity of interaction required to facilitate decentralised system management and VPP activity (Bitsch and Knox, 2002, CRISP, 2006), and there is now scope within existing technologies and regulatory frameworks for DG to participate in transmission balancing through offering scheduled ancillary services (Ilex and UMIST, 2004, Akhmatov and Knudsen, 2007, Lopes et al., 2007). Although at present only a very small number of DG is able to offer these services in the UK (Ilex, 2005), many of the necessary regulatory regimes are in place to allow aggregated groups of smaller generators and demand to participate in offering transmission level ancillary services (NGET, 2006).

The VPP can facilitate the devolution of the system management necessary for systems with a large number of DG and controllable loads (Dielmann and van der Velden, 2003). Further research has demonstrated the potential application of VPP for managing the schedule of different types of energy generation and demand (electricity and heat) (Shultz et al., 2005) and for distribution network management as reported in (Caldon et al., 2004). A number of vendors has also developed energy management software focusing on the generation scheduling based on the concept of VPP (Encorp, 2002, SaarEnergie, 2004, AREVA, 2006). On the commercial front, VPP has been used in Belgium and The Netherlands as a vehicle to make physical and financial call options with a pre-defined strike price (Willems, 2004) and in Germany and the UK to offer system balancing and ancillary services from aggregated groups of distributed generation and demand units (Platts, 2004, Platts, 2005, DTI, 2006d).

In this thesis, the functionality of the VPP as an aggregator of distributed energy resources and a facilitator of transmission access is explored and developed in more detail. Beyond network access, the VPP concept can also allow DG and demand to access to the energy and ancillary services markets. In this way the VPP configuration of DG and demand can contribute to the full integration of distributed energy resources in system operation and management. Further elaboration of the benefits of integration of DG and demand into system operation and management in this way is out of the scope of the thesis. However, some aspects of this additional function of the VPP will be touched on in the following sections which provide an insight into the benefits of aggregation of DG, and elaborate on the technical and commercial functionality that the VPP configuration and characterisation can provide.

5.3 Characterising the VPP[48]

As illustrated in Figure 5-1, the Virtual Power Plant (VPP) is comparable to transmission connected generating plant. Transmission connected plant has a profile of characteristics such as, schedule of generation, generation limits, operating cost characteristics. Using this profile individual plant can interact directly with other market participants and the system operator to offer services and make contracts. Via direct communication with the transmission system operator or through market-based transactions, a transmission connected generating unit can contribute to system management and can be made accountable for use of the system with exposure to relevant charges. Generation output and other associated services can be sold through interaction in the wholesale market or direct contact with energy suppliers and other parties.

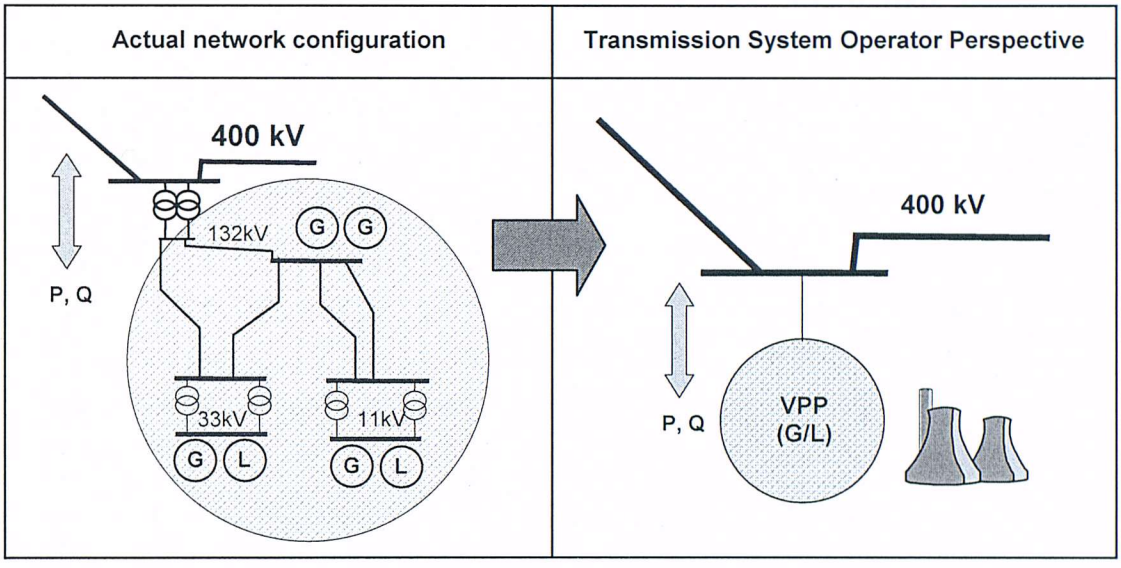


Figure 5-1: Characterisation of distributed generation (G) and demand (L) at various voltage levels in the Distribution Network as a Virtual Power Plant

Individual energy resources (generation and demand) connected in the distribution network do not have sufficient capacity, flexibility or controllability to make these system management and market based activities cost effective or technically feasible. However, with the creation of a Virtual Power Plant from a group of DG and controllable loads, these issues can be counteracted. As illustrated in the figure, from the network configuration perspective, a section of distribution network can be composed of many diverse generation units and loads; however, at the transmission-distribution boundary (the 400kV-132kV transformer in the figure) there will be a single set of PQ characteristics (i.e. generation capability characteristics; active and reactive power production capability) that represents the capabilities of the entire section of

[48] The characterisation and elaboration of the VPP concept is based on work undertaken by the author as part of the FENIX project (www.fenix-project.org) of which she is a part. This work has also been published: PUDJIANTO, D., RAMSAY, C. & STRBAC, G. (2007) Virtual power plant and system integration of distributed energy resources. *Renewable Power Generation, IET,* 1, 10-16.

distribution network below. From the TSO perspective, illustrated on the right hand side of the figure, the VPP is a formal aggregation of these generators and loads (and network characteristics), which defines and presents the single set of PQ characteristics to the TSO, in the same way as a single, large transmission connected generator would provide its generation capabilities.

Given this, a Virtual Power Plant is a flexible representation of a portfolio of smaller generators and demand. A VPP not only aggregates the capacity of many diverse units, it also creates a single operating profile from a composite of the parameters characterising each contributor to the portfolio. It can also incorporates a spatial (i.e. network) constraint into its description of the capabilities of the portfolio, as well as describing the aggregate cost characteristics of the resources. The VPP is characterised by a set of parameters usually associated with a traditional transmission connected generator, such as scheduled output, ramp rates, voltage regulation capability and reserve. Furthermore, as the VPP also incorporates controllable demands, parameters such as demand price elasticity and load recovery patterns are also used for characterisation of VPP. Table 5-1 outlines some examples of generator and controllable load parameters that can be aggregated and used to characterise the VPP.

Generator parameters	Controllable load parameters
• Schedule or profile of generation • Generation limits • Minimum stable generation output • Firm capacity and maximum capacity • Stand-by capacity • Active and reactive power loading capability • Ramp rate • Frequency response characteristic • Voltage regulating capability • Fault levels • Fault ride through characteristics • Fuel characteristics • Efficiency • Operating cost characteristics	• Schedule or profile of load • Elasticity of load to energy prices • Minimum and maximum load that can be rescheduled • Load recovery pattern

Table 5-1 Examples of generation and controllable load parameters for aggregation to characterise a Virtual Power Plant

Given that a VPP is composed of multiple generation and demand units of various technologies with various operating patterns and availability, the characteristics of the VPP may vary significantly in time. Furthermore, as the units that belong to a VPP will be connected to various points in the distribution network, the network characteristics (network topology, impedances, losses and constraints) will also impact the overall characterisation of the VPP.

The VPP is essentially a facilitator of access for the units in the portfolio to a wide range of markets. The VPP can be used to facilitate generator trading in the wholesale energy markets (e.g. forward markets and the Power Exchange) and can provide services to support transmission system management (for example, various types of reserve, frequency and voltage regulation). In the development of the VPP concept, these activities of market participation and system management and support are described respectively as "commercial" and "technical" activities, which derive two roles of Commercial VPP (CVPP) and Technical (TVPP)[49].

5.3.1 Commercial VPP activity

CVPP overview and characteristics

The commercial VPP is a representation of a portfolio of distributed energy resources that can be used to participate in energy markets in the same manner as transmission connected generating plant. Being part of a CVPP allows DG and demand to access the benefits of aggregation with other units. Aggregation of several distributed generators and loads can smooth the peaks and troughs in output caused by intermittency or variability in generation; for example, through matching the output of several uncorrelated (or negatively correlated) generators (Ilex, 2001) or taking advantage of diversity in wind resources across different locations (Holttinen, 2004, Milborrow, 2003, Dale et al., 2004). Aggregation of output in this way reduces the risk of imbalance and penalties incurred through falling long or short on a predicted output (Lampaditou and Leach, 2004) and can create a more flexible and reliable output that can gain additional revenue through offering ancillary services back to the grid (Marnay et al., 2000). When matched with demand, aggregated generation can provide a better match to variable demand loads (Born, 2001, Sinden, 2005), and controllable demand could also be used to balance a portfolio of resources participating in the wholesale energy markets and assist in provision of ancillary services to the system operator (DGCG, 2005, Ramsay and Leach, 2005, Ilic et al., 2007).

For DG in the portfolio (particularly intermittent or variable generation), this approach reduces imbalance risk associated with lone operation in the market and provides the benefits of diversity of resource and increased capacity achieved through aggregation. DG can experience economies of scale in market participation and benefit from intelligence on market participation to maximise revenue opportunities.

[49] These should not be confused with the "financial" and "physical" VPP reported in WILLEMS, B. (2004) Physical and Financial Virtual Power Plants. Leuven, Belgium, Catholic University of Leuven. which refer to physical and financial call options with a pre-defined strike price.

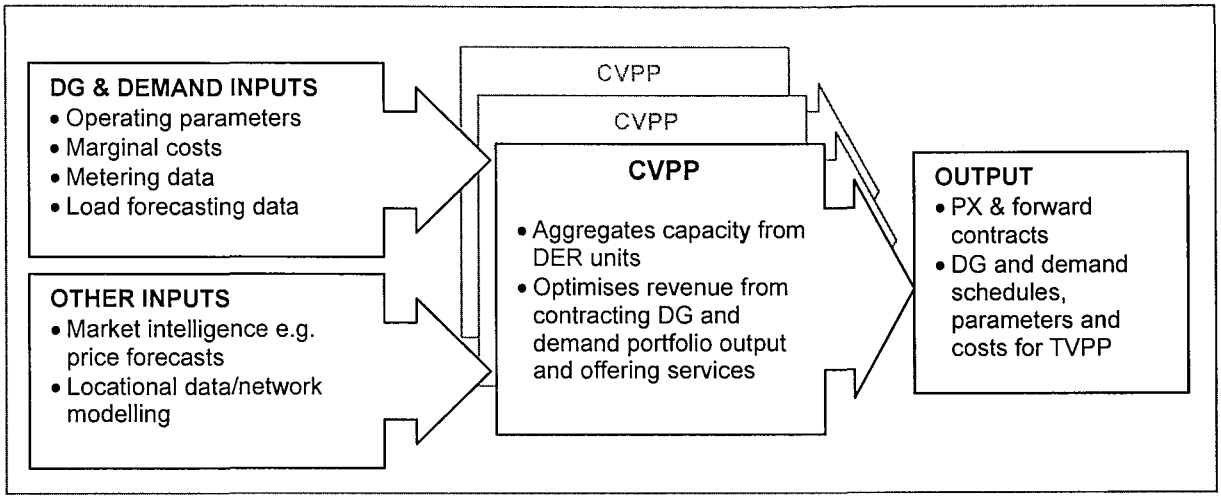


Figure 5-2: Inputs to- and output from CVPP activity

Figure 5-2 illustrates the required inputs to create a CVPP and the outputs of the aggregated portfolio. Each unit that is included in the CVPP portfolio submits information on its operating parameters, marginal cost characteristics. These inputs are aggregated to create the single VPP profile representing the combined capacity of every unit in the portfolio. With the addition of market intelligence, the CVPP aggregating agent will optimise the revenue potential of the portfolio making contracts in the Power Exchange (PX) and forward markets, and submitting information on the DG and demand schedules and operating costs to local system operators.

The CVPP portfolio composition and agent

In systems allowing unrestricted access to the energy markets (i.e. any system constraints caused by contracts in the market, or other locational issues are not accounted for at the time of contract creation, as is the case in the current UK market), the CVPP portfolio can include resources from any geographic location in the system. However, in markets where energy resource location is critical (such as in an LMP market, or in the proposed new framework for transmission access, with short term pricing of access by location) the CVPP portfolio will be restricted to include only resources from the same locality (i.e. the distribution network area or transmission network node). In these instances, a third party aggregator agent can still represent distributed generation and demand units from various locations, but aggregation of resources must occur in discrete portfolios characterised by geographic location.

In theory, the CVPP can be composed of any number of units and individual participants are free to choose an aggregation agent to represent them to the system (i.e. to the transmission network, wholesale and balancing markets etc.). This commercial VPP aggregation function can be undertaken by a number of market actors including incumbent Energy Suppliers, third party independents or new market entrants.

5.3.2 Technical VPP activity

TVPP overview and characteristics

The Technical VPP provides visibility of energy resources connected to the distribution network to the TSO, allowing DG and demand to contribute to transmission system management activities[50].

The TVPP aggregates and models the PQ (generation) and cost characteristics of a system containing DG, controllable loads and networks within a single electric-geographical (grid) area, essentially a description of sub-system operation and operating costs. A hierarchy of VPP aggregation may be created to characterise systematically the operation of distributed units at low, medium and high voltage regions of a local network. Essentially, the TVPP generates LMPs for individual users of the distribution network, and aggregates these price and operating characteristics into a collective profile. The aggregated profile increases in numbers of participants as the VPP aggregation hierarchy incorporates the higher levels of the network. This culminates in a single profile at the distribution-transmission network interface representing the entire local network.

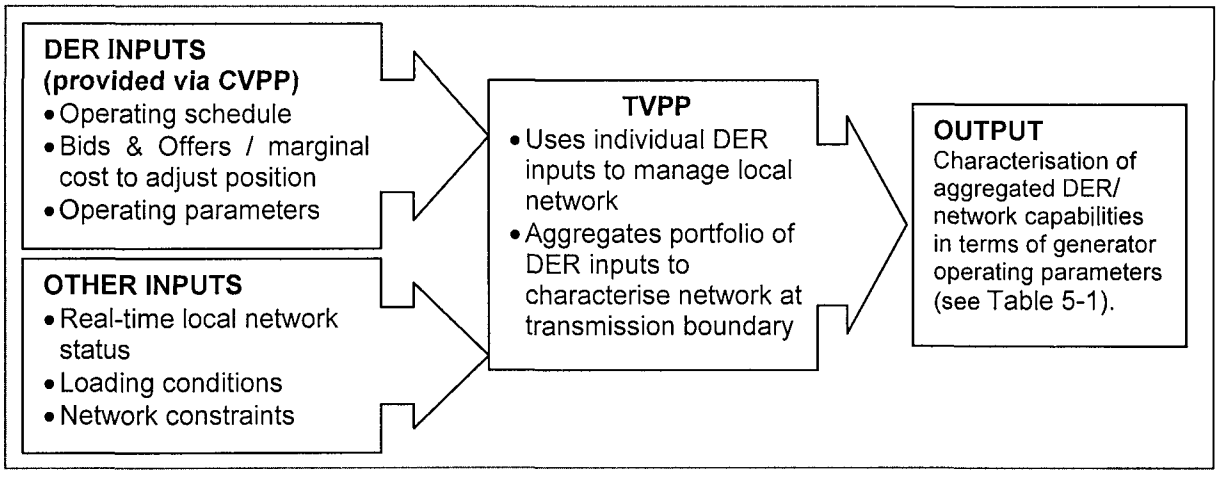


Figure 5-3: Inputs to-and outputs from TVPP activity

Figure 5-3 summarises the required inputs and outputs that characterise TVPP activity; information on generation and demand in the local network is passed through by the various CVPPs operating agents that represent units in the area. In the local distribution network, DG and demand operating positions, parameters and the bids-and-offers collected from the CVPP agent can be used to improve visibility of both generation and demand to the DSO. It can also be used to assist with real-time or close to real-time network management for the TSO and to

[50] Aspects of the TVPP can also facilitate use of generation and flexible demand capacity in the distribution networks should active network management be desirable. But this is not an aggregation function; this just uses the information gathered for the TVPP profile to control individual units in relevant locations for distribution system management purposes.

provide scheduled ancillary services. To facilitate DG and demand access at the transmission level, the DNO aggregates the operating positions, parameters and cost data from every unit in the network, together with detailed network information (topology, constraint information etc). It then calculates the contribution of each participant in the local system to the flow at the GSP and forms the TVPP profile. The TVPP is characterised at its point of connection to the transmission system, using the same parameters as transmission connected plant (e.g. as outlined in Table 5-1). This TVPP grid aggregation profile and marginal cost calculation (reflecting the capabilities of the entire local network) can be evaluated by the TSO along with other bids and offers from transmission connected plants, in order to provide real time system balancing.

Example of TVPP activity

TVPP aggregation algorithms to describe and characterise the PQ characteristics of sections of distribution network have been developed in (Pudjianto et al., 2007). Although the author was not directly involved in the development of the TVPP model outlined below, presentation of the results from this work is given here to demonstrate the concept and outputs of the TVPP, and to illustrate how this characterisation can interface with the existing UK market frameworks.

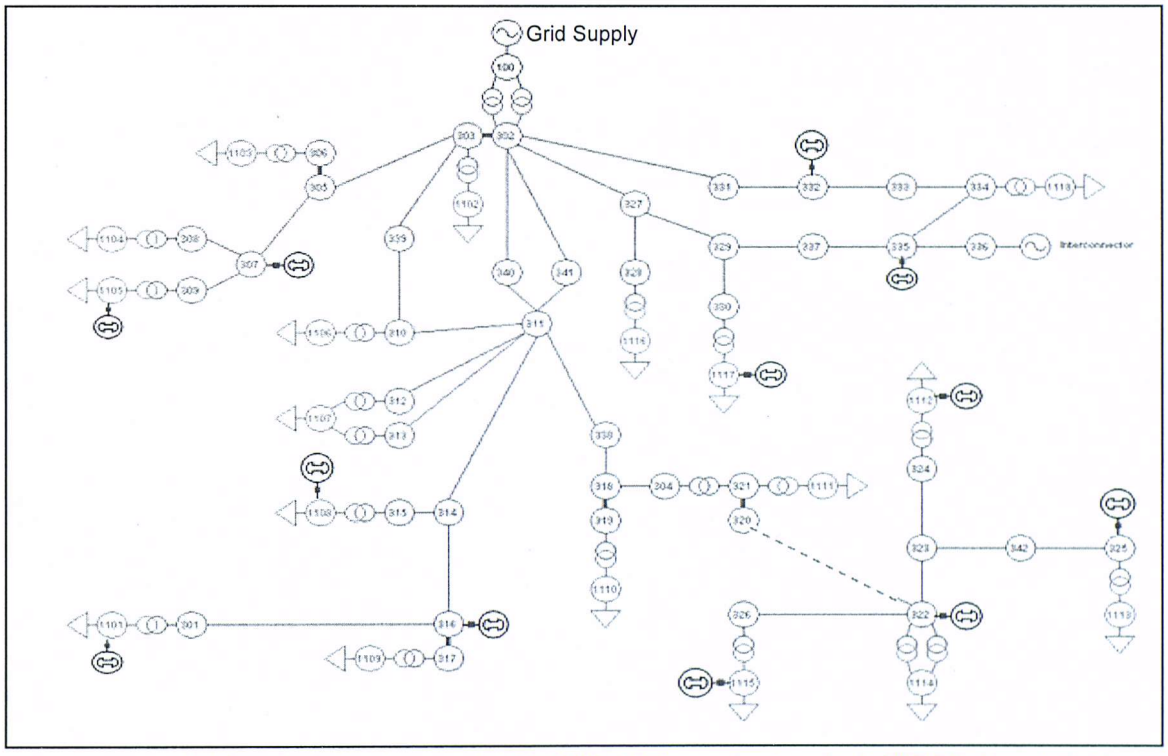


Figure 5-4: UK Generic EHV voltage model (DG&SEE, 2007) mapping to a single VPP PQ characterisation

The example is based on the UK Generic Distribution Network Model, developed by the CDG&SEE and is shown in the Figure 5-4 below. The topology and network characteristics of the selected model have a resemblance to rural network characteristics in the UK. The model consists of one 132/33 kV substation, 33 kV feeders, a number of 33/11 kV substations and

some loads connected at 33 kV and 11 kV. For this example, the 132 kV node is assumed to be a point of connection between transmission and distribution systems. Total load in the network was set to 12.4 MW and 2.5 MVAr. This represents an off peak load condition. Data for this model can be obtained from (DG&SEE, 2007).

A number of DG were added into the model and placed into various locations in the network, as shown in the figure. The range of MW (active power) and MVAr (reactive power) output from the aggregated DG assuming they are connected at one busbar is between 19.75(min) and 40.25(max) MW and between -22.78 and 22.78 MVAr respectively. The DG are scheduled to produce 30.5 MW output for this snap-shot condition. Thus, since output of DG is higher than the load, it is scheduled that this will export power to the grid. A constraint was introduced in one part of the system that would restrict the export from the area on the right hand part of the tie line to 10 MW (illustrated in the figure with a dashed line).

Creating the TVPP equivalent of the system shown in Figure 5-4 is a challenging task. The approach used in (Pudjianto et al., 2007) was an optimal power flow (OPF) algorithm. The OPF can be used to find out the maximum capability of injecting or absorbing active and reactive power at the point of connection between transmission and distribution without violating operation constraints of the generators, loads and the network. At the same time, OPF can also be used to ascertain the changes in generation cost due to the requirement to increase or decrease generation output from TSO and/or DNO.

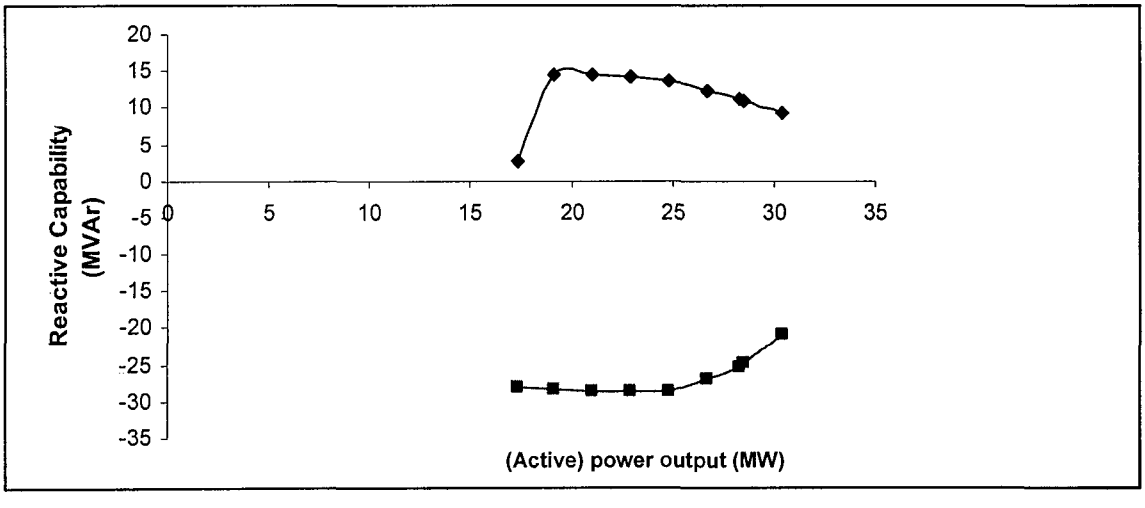


Figure 5-5: PQ characteristic of the TVPP

The PQ characteristics of the TVPP obtained from an OPF are shown in Figure 5-5. The figure illustrates the reactive power capability against increasing (active) power outputs from the VPP.

The characteristics are similar to the conventional generator PQ characteristics. In addition to the PQ characteristics, the OPF can also be used to find the characteristics of aggregate generation costs of the TVPP. This information can be presented in different ways depending on the type of electricity market. Under the spot market approach (as in the UK), bids and offers are needed from the TVPP for participation in the balancing mechanism. In this example, bids (the amount the TVPP will pay to decrease output) and offers (the amount the TVPP should get paid to increase output) for the TVPP were determined using the OPF. The results are illustrated in Figure 5-6.

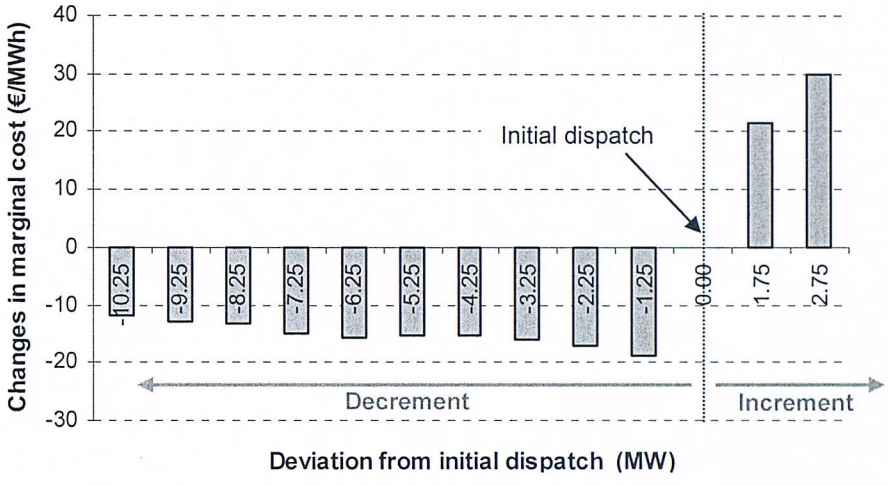


Figure 5-6: Bid-offer ladder from the TVPP

This is the same as a bid-offer ladder that would be submitted by transmission connected generation to the TSO, providing cost data on the charge (or payment) per MW of deviation from the initial dispatch that is required. In this example the bids and offers submitted by the TVPP are based on the marginal cost of generation, in reality the costs submitted may deviate from the marginal costs (e.g. as a result of market power, to take advantage of a strategic position in the network). If the TSO does not require changes in the final position of the TVPP and the scheduled output (initial dispatch) is met, the TVPP will not get paid or pay. However, if the TVPP is asked to decrease or increase generation for system balancing, this will incur some payment or charges to the network operation according to the submitted bid offer ladder[51].

The TVPP agent

To provide a comprehensive TVPP profile, and to provide data to the TSO on net flows at the GSP, requires local network knowledge and network control capabilities; naturally, the DNO will be best placed to carry this role. However, with its monopoly position, and considering the

[51] What has been demonstrated in this example (and in more detail in the referenced paper) is a preliminary finding of the work to characterise the TVPP. Other characteristics such as ramp rate, frequency response, fault level and dynamic characteristics of TVPP also need to be determined.

implications of the DNO operating in the transmission based markets on behalf of DG and demand in the TVPP portfolio, careful consideration is required to assess the implications for competitiveness, and the opportunities for the DNO to exert undue market power or tilt the arrangements in favour of particular system users. Further research into the contractual and regulatory implications of this arrangement will certainly be required.

In addition, with this TVPP data gathering capability, the DNO role could also evolve to include active management of the distribution network (i.e. not aggregating the data into a TVPP, but simply using the costs and output information for system users to control the distribution network in real time), analogous to a transmission system operator.

5.3.3 *Interaction between CVPP and TVPP*

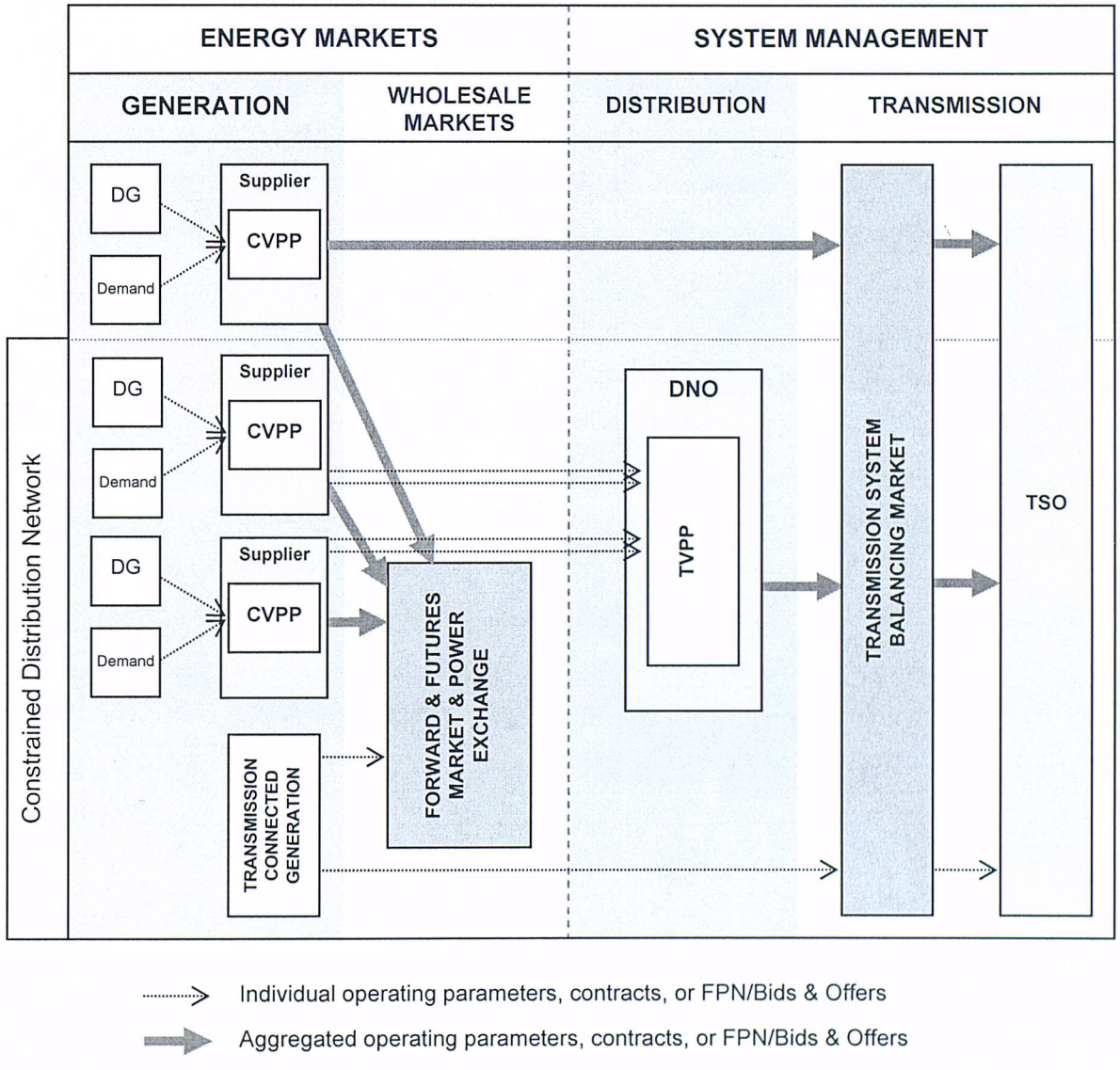


Figure 5-7: Commercial and Technical VPP activity in energy market and system management context

The interaction between the CVPP and TVPP is illustrated in Figure 5-7. The figure shows the respective roles of the Commercial and Technical VPPs and their interaction with each other and the wider system. The CVPP is operational in the energy markets, and responsible for passing information on distributed generation and demand through to the TVPP. The TVPP is engaged in system management, and facilitates management of local network constraints as well as aggregating generation and demand with local network parameters for presentation at transmission level.

In the instance of an unconstrained distribution network (shown on the top row of the figure), the energy supplier optimises the position of its CVPP portfolio in the wholesale markets as usual. In addition the supplier can also optimise the position of its CVPP portfolio in the balancing market. Although it should be noted that to offer location specific transmission network balancing the CVPP must be separated into smaller portfolios representing Grid Supply Points on the transmission network. The TSO then evaluates the CVPP offering along with bids and offers from transmission connected generation.

If the distribution network is subject to constraints (or requires active management) this is not possible, instead the CVPP optimises the position of its portfolio with reference only to the wholesale markets (see the bottom rows of the figure). It then passes the generation and demand output schedules and operating parameters on to the TVPP. This can then be used to offer transmission balancing services which the transmission system operator can evaluate along with bids and offers from transmission connected generation.

From the transmission system management perspective, the interaction between transmission and distribution (on the right hand side of the figure) will be infiuenced by the level of control and active management in the distribution network. In a scenario of passive distribution network management of a strong network with ample headroom for generation and demand fluctuations, the contribution that DG and demand can make at transmission level (to system management) could be material. However, in the instance whereby the distribution network is actively managed to utilise all latent network capacity (and distribution network operation is at the margins of the capabilities of the network), the availability of VPP services at higher voltage levels will diminish. An actively managed distribution network will demand flexibility and participation from demand and generation connected in the lower voltage networks, with the knock on effect that there will be less capacity available for use at transmission level. The TVPP profile will report the characteristics and parameters of the network below the transmission boundary and make the transmission access requirements visible, but the resources in the VPP

portfolio will have little flexibility to change this profile in response to transmission demand for services.

5.4 Representation and the role of the agent

For DG to be represented at transmission level under the net model proposed in Chapter 4, a mechanism for aggregation and calculation of net position is required (i.e. the VPP). This characterisation and aggregation function should be controlled by a single agent to overcome the logistical problem presented by the TSO attempting to coordinate contracts between hundreds of thousand if distribution network users. The most obvious candidates for such a role within the current system would be the incumbent Energy Suppliers or DNOs[52].

Although many Distributed Generators are registered under an Energy Supplier (usually via a Power Purchase Agreement (PPA) for sale of their output) and this existing arrangement could be a useful platform for the purchasing of appropriate transmission access rights, there are difficulties with this approach posed by the competitive nature of the supply business.

Distributed generators are free to choose which Supplier they will register under, and can (subject to the contractual arrangements of the PPA) change Supplier if they wish. Transmission access for DG is best allocated on the basis of a net position for all DG (and demand) in a specific geographic area to account for diversity in the output of a group. An Energy Supplier is unlikely to be able to capture the full benefits of diversity as many Suppliers may be representing DG in a single distribution network area. In addition, if a Supplier determines the net position of a group of DG within a particular GSP this is calculated on the basis of the net access requirements of the group; mobility of DG to other suppliers will affect this net position. As the allocation of access is based on a net position, it is complex to confer individual rights to generators. So, for generators transferring to another Supplier, there will be significant issues around ownership of transmission access rights and transferral of those rights.

Under the Supplier agent model it is likely that this can only operate if all DG are given an individual access allowance (similar to an individual TEC – the gross model approach). This would negate any benefits of diversity, and forego the opportunity to include demand in the calculation of access requirements.

[52] There is also the role opportunity for a third party consolidator to take on this role; a good example of this would be the (only) existing UK Consolidator Smartest Energy (www.smartestenergy.com). The opportunities for third part consolidators and similar are explored in the paper: RAMSAY, C. & LEACH, M. (2005) Can Virtual Utilities Revive the Consolidation Market? *BIEE Academic Conference: European Energy - Synergies and Conflicts* St. Johns College, Oxford University, British Institute of Energy Economics.

The DNO agent model overcomes these problems and facilitates the generation/demand net approach. Each DNO is responsible for calculation of the net position of all generation and demand in their jurisdiction, allowing maximisation of the benefits of diversity. Generators will interact directly with the DNO, who will make arrangements with the TSO on their behalf. Generators are free to change Supplier, but access arrangements for transmission will remain fixed with the DNO, and based on the location of DG in the network and its patterns of output in relation to other generators and demand.

Importantly, the DNO is also the only agent that is capable of providing detailed information on the actual state of the physical flows at the transmission distribution boundary. The distribution network sits between DG and the TSO, network constraints and losses at this level will significantly modulate the characteristics of DG as seen by the TSO. Distribution network topology changes in real time, such that the DNO is the only party with sufficiently detailed network knowledge capable of determining how individual DG (and demand) activity will contribute to the net flows at the transmission-distribution boundary.

Furthermore, in the future, distribution networks may be actively managed, and DG could be used to contribute to transmission system management. In this situation, the evaluation of feasible flows across the distribution–transmission requires detailed knowledge about the real time topology and availability of distribution networks. Again, the DNO is the only agent with detailed information suitable for elucidating actual net transmission capacity requirements at the transmission-distribution boundary.

5.5 Conclusions on developing transmission network access for DG

Under the Business as Usual future, large-scale penetration of DG and transmission connected renewables will displace a significant amount of the energy produced by conventional plant. However, as this new generation and the demand side are not provided with cost reflective access they cannot integrate into system operation, so conventional generation continues to be necessary for provision of system support services (e.g. load following, frequency and voltage regulation, reserves) and is required to maintain security and integrity of the system. This implies that a high penetration of non-conventional generation is unduly limited in the capacity of conventional plant it can displace. Given that DG is connected to the distribution networks, maintaining the traditional passive operation of these networks and the philosophy of control provided through conventional generation will necessitate increase in capacities of both transmission and distribution networks. By not integrating these new technologies, the existing framework is failing to recognise and reward the value that RE, DG and demand can offer and

favours conventional generation; a situation which will lead to inefficient operation and sub-optimal system development.

Alternatively, by developing access arrangements that result in the full integration of DG and demand side into network operation and development as proposed in the "Integrated Future", transmission connected renewables, DG and demand side will take the responsibility for delivery of system support services, alongside the remaining conventional generation. In this case the new generation will be able to displace not only energy produced by incumbent conventional generators but also their controllability, reducing the capacity of central generation as in shown in the figure. To achieve this, the operating practice of distribution networks will need to change from passive to active. This will necessitate a shift from the traditional control philosophy to a new control paradigm of coordinated centralised and distributed control. This future requires significant Information and Communication Technology (ICT) capabilities to facilitate interaction between thousands (potentially millions) of DG units and demand participants (as well as transmission connected generation) and the system operators, as well as new decision support tools to interpret and act upon the new information presented by integrated DG. This will bring an increase in complexity of system operation; however, with the correct development and innovation this new paradigm of shared centralised and distributed control should facilitate the development of more reliable, cost effective and sustainable systems that achieve maximum utilisation of all the resources connected within them.

This transition towards full integration of distributed generation and demand could be achieved through the commercial and technical VPP activities. In future, system management will rely on support from a significantly larger pool of resources across wider network areas. As the transition towards greater integration of DG and demand is made, appropriate commercial and regulatory frameworks such as those presented in Chapter 4 will need to be developed to ensure that the transmission access arrangements allow a full representation of distributed energy resources at transmission level as well as participation in both market and system operation.

Development of information, communication and control infrastructure to support this development will be a major challenge for realising this future. However, this necessary increase in complexity to deal with large numbers of small scale distributed resources will also facilitate realisation of the true value of distributed energy resources in the system. It will improve access to energy and system management markets for DG and demand, optimising the utilisation of system capacity and the efficiency of operation.

CHAPTER 6: Discussion, conclusions and further work

6.1 Discussion

6.1.1 Summary of findings

In the introduction to this thesis the core role of the network in the modern power system was described; namely to securely and efficiently transport power from generators to demand customers. The introduction highlighted that the existence of a network facilitates competition in generation and supply by allowing customers to access the cheapest generation resources regardless of their location in the system. It emphasised that the concept of fair and cost reflective network access is fundamental to the development of efficient markets that create an environment in which all system users follow the same rules and are given an equal ability to compete. Achieving this optimal, cost reflective outcome that maintains and develops a competitive market in network access for a future low-carbon power system has been at the centre of this research.

The work identified the main features of network access and the regulatory structures that support it, and explored the impact and value of the new renewable and distributed generation that is entering the system and highlighted the latent potential of the demand side. Using this review of the old and new systems a critical analysis of the interaction between the physical system and the evolution of regulation was undertaken. The analysis observed the present arrangements in the context of the future system and used this to identify gaps in the market and regulatory framework that failed to represent the physical manifestation and fundamental economics of the new system. Finally, in response to the gaps identified in the current arrangement, a new framework for the creation of enduring access arrangements suitable for the future low-carbon power system was discussed and developed, and a technical architecture for the integration of DG and demand was explored.

6.1.2 Changing roles in transmission network access

Challenging the appropriateness of the current GBSQSS

Markets and regulatory frameworks are developed to achieve optimal allocation of resources in particular systems; they are tailored to meet the needs of the incumbent technologies and operating philosophies. As the profile of technologies changes for example with the penetration of renewable and distributed generation, accordingly market and regulatory arrangements may also need to change to reflect the changing characteristics of the system. The current system has been developed in the context of large-scale transmission connected generation. The standards that guide the design and development of the system, the GBSQSS, are a proxy to deliver optimal development of this system.

However, with the penetration of non-conventional generation technologies and a changing physical system, there is the growing concern that this proxy is no longer suitable for the system that we have (or are moving towards). Recognition of the issue of spatial and temporal differences in renewable and distributed generation versus conventional generation is the key to developing an optimal system that rewards generators appropriately, sends the correct signals regarding location and timing of output, and does not discriminate against any participant. For example, the role of reliability in network standards is likely to change. Previously a driving factor in network design, new generators entering the system are less able to make a contribution towards system reliability, to the extent that they will drive very little in terms of capacity requirements to ensure that their output can secure peak load. Instead the relevance of economic efficiency may come to the fore, with additional network capacity being required simply to allow demand to access low marginal cost power in locations remote from demand.

Another key difference is in the drivers behind network design. Currently, the system is driven by peak network conditions and the presumption that all generators will be using the system at peak output during peak demand periods. This means that the network is designed to support simultaneous peak outputs from generation, and generators are charged accordingly. One of the key differences in conventional and non-conventional generation is that this approach no longer holds for systems with a high penetration of renewable and distributed generation. These technologies have lower load factors and different operating characteristics driven by factors other than load following such as the weather and heat demand. Their requirements for network capacity are such that when there is sufficient diversity in generation it is economically efficient to share network capacity between users. It is no longer efficient to size the network for simultaneous peak output because the probability of this occurring is usually too low to justify the investment expense. This element of sharing also drives a move towards the requirement for a valuation of short term access and choice in purchasing access over a variety of time frames. If

access is to be shared, then there will be occasional points of congestion when the access provided is insufficient. Short term access prices are required such that system users can optimise their positions under these circumstances.

Given this importance of spatial and temporal issues, and the difference between conventional and non-conventional generation in this respect, it is apparent that the new system will have different requirements. The optimal balances between investment in capacity and management of operational costs will change and this needs to be reflected in new GBSQSS – or some other proxy. Standards are the starting point between the TSO and system users on how the network should develop, and as such any new standards should not ignore (or oversimplify) what users want. In a competitive market environment user choice is the key; if the current standards are to remain they must reflect this and evolve to represent the increasing number of options in system development and operation.

Maintaining the separation of energy and access

The current market arrangements under BETTA maintain a separation of energy and access, so that energy is sold in the wholesale markets without including the value of short term network access in the wholesale price. In the current system, a homogenous group of generation units uses the system in a similar and predictable fashion, constraint costs are low and the impact of location on the value of power is minimal. So this approach of separating energy and access has not been damaging; the future system could change this.

New, renewable generation is entering the system in potentially very large amounts and because of the availability of the wind resource this new generation must be sited in an area of the network that is already experiencing congestion, and it will exacerbate the already apparent north-south flow of power. It is likely that the value of access in these already constrained areas could change quite significantly (with time of use of the system and weather conditions) and that this could massively impact the value of energy from particular locations. Failure to reflect these differences in value that change with both location and time, and to pass the costs on to the users of the system that impose them, could result in a non-competitive environment of sub-optimal development and considerable cross-subsidy between users. It also prevents certain system users (primarily demand) from receiving cost reflective price signals that could stimulate efficient responses in terms of system operation and promoting optimal long term development in non-network solutions (i.e. demand response could mitigate network reinforcement).

For the current conventional system, energy and access are entirely separate and dealt with under different philosophies. Electricity is sold on the basis of short run marginal cost derived in the power exchange (with subsequent forward and bilateral contracts being derived from this

short-run price). Transmission access is valued on the basis of long term investment costs derived from a philosophy essentially rooted in a central planning approach; there is no indication of the short term value of access. This approach tends to overvalue access for (low load factor) non-conventional generation through only allowing purchase of full, fixed, long term products. Moreover, it also undervalues access in the short term in areas where constraints have become a material problem and where demand response and user choice for short term transmission access requirement should be made transparent to allow optimal resolution of the constraint.

Short term versus long term charging for network access

In future systems, transmission network capacity should be shared amongst various generating technologies and hence the network will be occasionally constrained. Users competing for this shared capacity will need the opportunity to exercise a choice between exposure to the short term cost of access (during the periods of constrained operation) versus purchasing a known-price firm-access product (that supports network reinforcement at marginal investment costs) and paying use of system charges. To allow this choice an ex-post short term market for access is required to reveal the value of transmission in real time. Within the present charging framework this cannot be achieved as this only considers long term transmission network access (or no access at all).

It is important to emphasise that this lack of any short term valuation of access is inherently linked with the way the transmission network is priced, namely long term investment based pricing. This approach intends to charge users based on the long term investment cost they impose on the network and prevents the application of the principle of sharing of transmission capacity which results in inefficiencies. This approach is also not in line with the pricing of wholesale electricity, which is based on ex-post short term generation costs. The current market arrangements separate consideration of energy and access and send no locational signals to users of the system on their short term impact on the system.

As a cost reflective short term value of access is unavailable, the present approach does not provide access choice to existing and new generators and prevents them from making efficient decisions regarding their use of the system in the short and long term. This results in inefficient operation of the generation system and inefficient future investment in transmission.

In summary, the current TEC based approach to transmission investment and pricing, which focuses on charging for long term access rights, cannot facilitate cost effective (and timely) integration of substantial amounts of non-conventional generation into the UK transmission

system. Fundamental revision of the current TEC based arrangements to reflect the diversity of different generating technologies and to incorporate the short term valuation of transmission is essential if access arrangements for systems with significant contribution from wind energy are to be cost reflective and transparent.

This thesis outlines a number of core criteria that should be considered in the development of enduring transmission arrangements: (i) cost reflectivity, (ii) availability of choice in access arrangements, (iii) reflection of differences in generation characteristics, (iv) representation of location and time of use, (v) sharing of access between generation technologies, (vi) continuity between short and long term value of transmission and (vii) flexibility to deal with increased uncertainty in future generation development.

These are the factors required to create effective and efficient arrangements that conform to the fundamental economics of a system with a high penetration of wind generation and provide a level playing field for all system users including demand. Through the analysis in Chapter 5 it is clear that the only access solution capable of delivering all these aspects essential to enduring transmission access arrangements is the development of a market for short term access based on ex-post pricing of access overrun.

It should be noted that the solutions proposed to the transmission access questions are, however, nothing new in terms of market development and experience. All these ideas for short term access and increasing the market approach to access are within the present understanding and literature on this subject and implemented with growing success in markets across the world. The proposed framework is a step change from the present orthodoxy in the UK, and its adoption would represent a fundamental shift in the incremental evolution approach to regulation that has been adopted to date. The arrangements for transmission network access need radical change to allow the optimal and efficient representation of low-carbon generation technologies – but this radical change is achievable using the solutions already at work in other markets.

6.1.3 Changing roles in distribution network access

Developing network access arrangements for generation

The primary feature of the current network access arrangements for the distribution is that they have been developed to serve the requirements of demand alone. Because of the historical lack of generation connection in the distribution network and the passive unidirectional operation philosophy, the driving factor in development and design of the networks has been in securing demand and ensuring quality of supply to demand customers.

The first and most relevant challenge to distribution access arrangements therefore is the need to augment the emphasis of the current arrangements to include consideration of the requirements of demand in network operation and development. Without this consideration, as the penetration of generation grows in the network the current standards will be increasingly ill-equipped to direct the development of an optimal and cost effective network.

As an example, the ER P2/6 does not address the security of power transfers originating from generation. Because of the historical demand-only focus, currently DNOs are not required to provide a particular level of security to generator customers. Although the adaptation of the P2/6 methodology to include the contribution of generation in securing demand was a significant step forward in recognising the contribution of DG to network conditions, this still maintains the demand focus, and makes no mention of the security requirements of DG. Although not a material problem in the current system, offshore wind generation highlights a potential problem with this approach.

A number of the new offshore projects will be coming onshore with a point of connection in the distribution network rather than directly to the onshore transmission network. This means that distribution networks may be required to transfer energy between transmission operators. In such circumstances, the applicability of the offshore Security and Quality of Supply Standard could be undermined in the absence of requirements to securely transport the power flows from such generation across distribution networks. As the current arrangements may not provide sufficient certainty for the developments in offshore wind, it will be important to understand these requirements and to quantify the appropriate levels of network security to transport the output from generators. A possible development path would be to review the existing industry codes, practices and governance procedures followed by development of an SQSS for onshore distribution networks and a corresponding industry code.

DUoS for generation

A further example of this omission of generation from the distribution access arrangements is seen in the Distribution Use of System (DUoS) charging methodology. Although consultations have been underway for some years to amend the charging methodologies to reflect the impact and contribution of generation, the majority of methodologies in use are still based on the historical demand led approach. The impact of generation on distribution networks (in terms of costs and benefits) is site specific: it may vary in time, it will depend on the availability of the primary sources (important for some forms of renewable generation), as well as on size and operational regime of the plant, proximity of the load and layout and electrical characteristics of the local network. It is not, therefore, surprising that the relatively simplistic DRM tariff

structure, with network charges being averaged across customer groups and various parts of the network, cannot reflect the cost impact of distributed generation on distribution network.

It should be noted that DRM tariffs also have no real ability to capture the impact of multi-directional flows (caused by the presence of distributed generation) and cannot deal with the temporal and spatial variations of cost streams. One solution, already being discussed as part of the ongoing review of distribution network pricing, could be to move distribution access charging towards the transmission approach. Under this methodology, long term investment based pricing could incorporate and reflect the cost and impact of generation as well as demand on a locational (and time of use) basis.

Integrating DG and recognising its value

DG has an impact on the distribution across many areas. As described in section 1.3 (Figure 1-1), in a system with DG, to create access arrangements with a cost reflective regime requires recognition of this and realisation of the value and impact of generation according to its location in the network (and use of the network). These points of value for DG include:

- **Provision of security of supply for demand:** DG can provide a source of security of supply for loads in addition to the existing network. As is now reflected in the ER P2/6 standard, generation can be used to secure supply, providing an alternative non-network solution to a network problem. However, the majority of CI/CML come from faults in the 11kV network, so to be of assistance in securing load generation must be in place below the fault. This means that the majority of assistance from DG must be coming from those connected at low voltage – which is complex considering that these generators are smaller and less capable of delivering output with a confirmed level of certainty.

- **Reduction of import requirements:** Local generation connected at distribution levels, particularly at the lower voltage levels and close to demand will have the effect of reducing flows from transmission to distribution because demand is met locally. This means that the HV distribution network and transmission carry less load, and in some instances this can have the effect of releasing capacity and deferring investment whilst allowing load growth in the lower voltage networks. Variable generators like PV and wind make no contribution to this effect, but technologies such as CHP, μCHP and biomass plant can potentially make some contribution.

- **Reduction of Losses:** DG that is correctly placed (very near loads) and that has output correlated with peak loading of the network can make a significant contribution to the

reduction of losses in both rural and urban areas. However, this effect will be dependent on penetration density of the technology. Once the density exceeds a certain level in some areas, the positive impact on losses can be reversed. Because of its strong correlation with domestic energy demands (and peak demand conditions), μCHP has considerable potential for contributing in reduction of distribution network losses.

However, the present framework doesn't incentivise DNOs to use DG in this way. DNO revenue recovery is on Capital Expenditure (CAPEX) rather than Operating Expenditure (OPEX) which DNOs are incentivised to reduce. A network solution to a network problem such as rectifying voltage rise or mitigating faults results in an addition to the asset base. Utilisation of DG or active management techniques to solve or mitigate the same problem does not result in capital expenditure, but falls under the OPEX remit. These issues and incentives for integration of DG are currently under review in the ongoing Distribution Price Review.

In addition, the commercial frameworks are not in place to reward DG for these contributions to the network. However, the actual value of some of these services is currently very low. In the example of losses, although DNOs are incentivised to reduce losses, this is not an issue that has historically been a high priority for network operators (or something that has made a significant difference to their revenues). The same is true of activities such as contribution to security for demand and reduction in network capacity requirements. The distribution network is relatively strong (because of a history of passive operation that has ensured that the network is sufficiently strong to withstand a large amount of operational variation) so that value of these services is correspondingly low.

A final consideration on the use of DG to provide network services is on the implication of using intermittent/variable generators to provide system support and solutions to network problems for DNOs. This is a fundamentally different approach from the current method of providing system services which relies on network solutions (i.e. installing more network capacity, switchgear etc.) to reduce faults, ensure adequate security for demand etc. Using DG, some of which are inherently stochastic in nature or have limited availability, will change the level of certainty with which services can be delivered. Although this can be accounted for to some extent (the ER P 2/6 calculations on the contribution that generation can make to system security do account for availability and unreliability) the risk level of using DG is materially different to the network alternative.

By using DG for solving network problems DNOs will have to evaluate the risk and cost of non-delivery of service. This is not only a shift in the way that DNOs currently evaluate

solutions to network problems, but also creates potential incompatibility with the Quality of Supply incentive approach to regulation of the DNOs. The current approach to incentivising quality of service is about rewarding reductions in customer interruptions; using generators to secure demand may increase faults or will at least change the risk profile (and consideration of risk) associated with the likelihood of faults (and customer interruption). So in terms of balancing the costs of using DG versus network solutions this will also have to include a calculation of risk of non-delivery of services and the cost implications that this has for the quality of service/supply indicators.

6.1.4 The growing role of the demand side in network access

This research has identified changing drivers for demand side response and participation that would improve the competitiveness and cost reflectivity of the current arrangements. The key issue with the current arrangements is the lack of recognition that, at a physical system level, the impact of demand and generation on the network is equal and opposite; 1MW of demand injected into the network is the same as 1MW of demand curtailed (as long as there is no recovery of load during a subsequent period). The current transmission arrangements treat demand and generation differently, which introduces cross subsidy between parties, and curtails demand from taking an active role in the network (this is on the presumption that demand is inelastic). However, the changes that have been outlined in this thesis have demonstrated that the material difference between the current and future generation mix will stimulate different requirements in network access that could open up new areas of participation and more extreme price differentials that may stimulate demand to participate. But, this can only happen if demand and generation are treated equally and demand is exposed to its full impact on the network.

New wind generation is being sited by location of the wind resource rather than by location of demand. The transmission system will need to accommodate this new generation and manage the constraints it causes optimally. One of the alternative market arrangements proposed in this promotes the development of a market for short term access to send locational price signals to users of the network on the true costs of access. Under this approach, energy prices could be dramatically influenced by the cost of access in certain locations at certain times of the day. The wholesale price for purchase of wind generation in Scotland (i.e. near generation) on windy days could drop very low under this regime, giving demand the clear signal that increasing load during this time could be beneficial to the network. Although there are some non-market based ramifications and likely concerns around a solution that promotes the increase of demand as a solution to integrating more wind generation, these are certainly options that deserve more consideration and evaluation. Recent studies in Denmark have explored the impact of 50% penetration of wind in the country, and have highlighted the issue of very low prices for wind

on windy days, coupled with the opportunities for demand response to take advantage of this - potentially providing a new market for wind during peak periods that would give consumers a cheap source of energy, but would also provide a market for excess wind (EAEA, 2007). In Denmark where CHP is a significant source of heat and power, this option of engaging the demand side opens the opportunity for fuel switching. Instead of burning gas in CHP units to provide heat and power, excess wind is used on windy days to provide both, displacing the gas requirement.

A more long term question is the issue of integration of demand and providing this network user with the same access rights and ability to offer services as generation. Although not explicitly explored, the solutions proposed for transmission access arrangements are broadly applicable to fair treatment of both generation at distribution level and demand. Although in both instances further discussion to overcome various practical integration challenges is needed, as explored in the work on the VPP in Chapter 5.

6.2 Conclusions and recommendations

6.2.1 Response to research questions

The aim of the thesis was to uncover pathways for the evolution of the existing market and regulatory frameworks for network access to support the future low-carbon power system through maintaining a competitive environment and ensuring all generation and demand is provided with equal opportunity to participate and realise the full value of their contribution. From this aim a series of four research questions was identified to scope the research objectives and build a structure for the thesis. These initial research questions and the key conclusions on each are elaborated below, and following this are the overarching conclusions and recommendations from the thesis.

RQ1. What are the main challenges facing development of the market and regulatory arrangements governing network access for the future low-carbon power system?

The key challenge in the market and regulatory arrangements for transmission access will be in their suitable development to respond to the changing generation mix and location. As penetration of renewable and distributed generation increases (and the role for demand participation emerges) the generation mix will increasingly be driven by different characteristics than those reflected in the current planning standards. Further challenge is derived from the fact that the majority of new transmission connected renewable generation requesting access must be located in Scotland, where there is already transmission congestion. Understanding how much

transmission capacity these new users require and how they will use the network is the key to ensuring timely connection of these low-carbon energy resources.

In distribution, the challenge rests on the need to incorporate generation into the operation and investment philosophy of the network which currently centres only on meeting the requirements of demand. However, because the network is sufficiently strong to absorb the impact of increasing penetration of distributed generation, the access challenge in the distribution network is not a material issue in the short to medium term timeframe addressed in this thesis.

RQ2. What is the impact (costs and benefits) of non-conventional generation on the transmission and distribution networks?

At transmission level, the different impact of non-conventional generation such as wind is derived from the different operating characteristics and time of use of the network as compared to conventional generation. Intermittent and variable generation that is not load-following will tend to drive less capacity. Furthermore, diversity in generation technologies (conventional and non-conventional) will allow transmission capacity to be shared. In the short term, new renewable and distributed generation will contribute both positively and negatively to transmission constraints and power flows depending on location and time of use of the network.

For the distribution network with its focus on the satisfaction of demand customers, the impact of generation is felt in areas that have the potential to impact quality and security of supply for customers. DG can have both positive (reduction of losses) and negative (increase in fault levels and voltage rise effects) impacts in the short term. In the long term DG can drive the need for additional capacity, but if located and operated optimally can also contribute to a reduction in the need for network reinforcement (through contribution to network security and reduction of power flows at higher voltage levels etc.).

RQ3. Are the current network access arrangements still cost reflective when applied to systems with significant penetration of non-conventional generation?

At transmission level the current access arrangements are not cost reflective when applied to non-conventional generation because they fail to recognise the impacts outlined previously. They do not recognise differences in generation technologies that drive different impact on the network according to location and time of use of the system; nor do they properly recognise distributed generation. Furthermore, they treat demand and generation un-equally. There is no calculation of the short run value of network access, which limits user choice. Although a suitable proxy for the current conventional system, the future system with a significant

penetration of renewable and distributed generation technologies is materially different. As such, the future system has different requirements from the network in terms of short term use and long term capacity needs.

RQ4. What should the be the main features of enduring arrangements in access for future low-carbon power systems, and how should the technical architecture of the system support this framework?

The analysis undertaken indicates that the main feature of a new transmission access regime to support the future low-carbon power system should be the calculation of the short run value of access. This would open up the possibility for sharing of access between users and would provide all users with the information they need to make optimal decisions on their use of the network over a range of timeframes, particularly important for non-conventional generation which is variable in nature and not load-following.

A technical architecture to support this system (with reference to transmission access for distributed generation and demand) was discussed in the form of the VPP. There are no clear conclusions on how this architecture will progress, but it is clear that there are outstanding challenges still to be met in this area, such as development of ICT frameworks to support the coordination of thousands (even millions) of individual units in the distribution networks and to advance decision support methods to allow interpretation of signals from these units for System Operators to utilise.

6.2.2 Final conclusions and recommendations

Overall, three broad conclusions can be drawn from this work; each conclusion is stated and discussed in brief below. Following this is a critique of the research approach adopted and of the research aims, objectives and scope including detail on suggestions for further work in the area.

C1. The relevance of the network access question develops as the network becomes stressed; network access has limited value in a strong system with few constraints.

The value of access and need for action on network access arrangements is inherently linked to the status of the network and the available headroom in the system. The access question is becoming a material concern in the transmission system because of the additional generation requesting connection in an already congested region. If the network access arrangements are fully cost reflective then the costs passed on to generation and demand in these congested areas should reflect the additional stress (or timely assistance) they offer to the network. Under stressed network conditions these charges could make a material impact

on the final price of energy. At this point it becomes relevant and useful for full attention to be paid to the access requirements and individual impact of all system users.

Five years ago, in the distribution network, the main emphasis of regulatory review and development was on the challenge posed by generation entering the distribution networks and managing the 11kV network issues. Removal of barriers to DG was a key focus and successive reforms succeeded in systematically removing some of the most restrictive issues. However, the revolution in decentralisation of power generation has yet to materialise, as identified in the recent Energy White Paper consultation paper for DG, capital cost remains the primary barrier for DG entry to the system. Although there should be opportunities for DG to add value to its proposition through recognition of the positive impact it can bring to the network (or the mitigating impact on costs that can be achieved through active management), the distribution system is not currently stressed. These positive impacts that reduce losses and mitigate capacity reinforcements are small credits against a large cost (and against the relatively cheap alternative of network reinforcement). Until the penetration of DG begins to challenge the integrity of the distribution network and the system begins to value short term access as stresses need to be resolved in real time, there is little value in the positive benefit that DG (or other enabling technologies) can bring to the distribution network.

C2. Transmission network access regulation must move beyond incremental change and adaptation. A step-change in the regulatory and market arrangements for transmission access is required to keep pace with the physical changes in the power system.

This research and analysis has raised an important question on whether an approach which promotes only incremental changes developing the market and regulatory frameworks for network access keep pace with physical changes underway in the system. The physical power system has evolved quickly over last five years – particularly in terms of what is material and relevant in the generation sector. The recent development in access (the 2007 Energy White Paper Review and its precursors) has reflected the change in emphasis, namely the diminishing immediate relevance of distribution access concerns in favour of resolving transmission access questions that will help to get new renewable generation capacity (that is already waiting) online now. Although the reflection of these changes in regulatory reform is apparent, this analysis has highlighted an underlying concern that physical system is progressing beyond the rate of evolution in regulation. The implications of this are that with only incremental changes in access there is the growing danger that regulatory and market reform is not keeping pace with the physical changes. This will

ultimately be reflected in a lack of cost reflectivity and a non-competitive environment for all users.

The transmission network is built on the basis of deterministic standards, optimised to serve a system that will soon not exist. Standards can be adapted and improved to reflect these changes in the system, but they are part of a philosophy grounded in long term planning and charging that is fundamentally unsuitable for use in the new system. The analysis in this thesis suggests that in the case of transmission access, a more radical change is required beyond incremental improvement in the status quo. The gaps are so significant in terms of the growing importance of short term access to allow sharing of capacity and cost effective investment, that this thesis argues a radical rethink of the current transmission access arrangements (and philosophy) is required. A fundamentally different approach is needed, one which is grounded in the short term valuation of network access. This is a development that is wholly compatible with the overall policy remit to develop increasingly market based approaches to the operation and development of the sector with the aim of delivering a better deal for customers.

C3. Delivery of an optimal network to support a low-carbon power system can be facilitated by a competitive market approach to network access.

The competitive market approach can deliver optimal networks that recognise the contribution and impact of non-conventional (low-carbon) generation, but this approach needs to fully embrace the principles of market operation if all the requirements and characteristics of the future sustainable power system are to be incorporated into fair and optimal network access arrangements.

The key aspects for recognition are that all users should be given equal access to the network and charged proportionally to their use of the network resource. This means equal treatment and recognition of all generation technologies and also equal treatment of demand and generation. Supplemental to this is the recognition of location on the network and on the time and pattern of use of the network resources. This is required to ensure that the differences in impact between technologies and across geographic locations are taken into account, and is of particular relevance for non-conventional generation that is not characterised by traditional patterns of output or use of the network. Finally, user choice in access should be facilitated. Implicit in all traditional commodity market operations is the notion of consumer choice in purchasing that derives from price information; short term spot prices dictate the value of a commodity. Using the short term market approach, participants can then choose to make a purchase in real time, or to hedge their positions and

purchase ahead of time in forward markets or through bilateral contracts. Network access requires this same level of transparency for user choice. Calculation of short term value of access and derivation of long term value is fundamental. It allows users to make an optimal response in determining their network requirements and guides optimal network operation and investment for long term development.

6.3 Critique of the thesis and proposals for further work

Network access issues in the UK are an ongoing challenge which is experiencing an increasing profile with the announcement of a major review of transmission network access in the 2007 Energy White Paper (DTI, 2007 pg. 164). The research and analysis presented here frames the major issues surrounding the access debate in both distribution and transmission. Furthermore, the change in emphasis of the thesis to focus on the transmission network has strengthened this link with the current issues and ensured that the research aims and objectives remain valid and relevant. However, inevitably there are some limitations to the approach that was taken to explore these issues. These are presented in the following section along with a description of additional work to explore or alleviate these limitations. To conclude this chapter there is a final section on suggestions for further work to augment and take forward some of the main findings from the thesis.

6.3.1 Limitations of the approach

Whole system analysis limited to electricity

The whole system analysis adopted as the overarching approach for the research was limited in its scope to include only consideration of the power system. It does not extend beyond consideration of electricity networks to consider interactions with the gas networks and other energy services/energy storage options such as heat. Clearly the electricity, gas and energy storage concepts are all inextricably linked, as has been touched upon in Chapter 4; opportunities for fuel switching could arise if electricity prices drop dramatically in highly constrained network areas. These complex interactions have not, however, been thoroughly explored in this work.

This is particularly relevant in the context of distributed generation. The thesis examined only distributed electricity and did not explore the potential for a wider consideration of distributed energy. The implications of decentralisation of generation were largely bypassed because of the restrictive nature of the timescale chosen for this work, limiting the research brief to the short and medium term and exploration of the immediate issues for network access. However, there is potential for further exploration of the network access implications of various decentralised

energy scenarios. As developed in (Greenpeace, 2005), there are some considerable efficiency gains to be sought from a decentralised future that combines and optimises heat and power provision to localised regions/small towns. Exploring these options for decentralised energy networks and their interaction with the transmission network could have significant implications for access requirements at higher voltage levels.

None of this was explored in the thesis because of the restrictions in the time-horizon of the research. Further exploration of network access issues that incorporate all energy networks, could raise some interesting and relevant questions that would complement the work already carried out.

Additional work in this area could include;

- *Extension of the whole system analysis to incorporate an "energy system" approach, including reference to gas, heat, and electricity networks. Network access requirements could incorporate consideration of efficiency gains through local heat networks and the evaluation of potential for fuel switching or storage in this context (i.e. using electricity to generate heat, for heating/cooling purposes).*
- *Exploration of network access issues under alternative future scenarios for decentralised energy networks, e.g. a CHP dominated future, and extend to include theoretical concepts such as the "Energy Hubs" approach (Favre-Perrod et al., 2005, Geidl et al., 2007).*
- *Although there are some localised examples of the integrated (gas-electricity-heat) energy system working in practice (HoL, 2005), there has yet to be a comprehensive assessment of the benefits of the local CHP based approach for the UK network operation and development.*

Whole system analysis grounded in network access

The whole system approach was grounded in the analysis of network access, to the exclusion of considering the generation sector beyond the impact of non-conventional generation on the network. As such, the scope of the work didn't extend to include analysis of the impact of non-conventional generation on the incumbent generation sector. For example exploration of how much conventional generation might be displaced (or retired) by the influx of new technologies was not discussed, nor was the role of generation in provision of ancillary services to assist in management and balancing of the system or the impact of introducing intermittent or variable generation sources in terms of causing imbalance in the system. All this work was out of the scope of the thesis; however, the approach taken misses the opportunity to draw further links in terms of network impact from the changing generation mix and the role of generation in offering ancillary services and providing system reliability.

Some of these issues are touched upon in Chapter 5, with the development of the Virtual Power Plant concept. The VPP provides the technical architecture for the full integration of distributed generation and demand into transmission (and distribution) system operation. By providing transmission network access for resources in the distribution network the VPP also makes these resources visible to the TSO and potentially available for use in offering ancillary services. However, the majority of the research considers only the high level drivers for short and long term network access requirements.

Additional work could include:

- *Development of the scope to consider the implications of the full integration of renewable and distributed generation and demand on network access issues.*
- *Further exploration and development of the VPP concept, e.g. requirements and design of the VPP portfolio of resources. Explore, what kind of controllability and services should VPP offer? What problems can be resolved by DER/VPP? How can DER portfolios be characterised as VPPs with respect to dynamic and steady state characteristics given the stochastic nature of DG output? What new Distribution Management System / Energy Management System applications are required to make use of VPP based services?*
- *Development of a commercial and regulatory framework for the integration of ancillary service provision from non-conventional generation, or VPP portfolios.*

Development and impact of alternative scenarios for sustainable energy futures

The thesis has not developed or explored scenarios for alternative sustainable power futures. The work was grounded in the short to medium term, and the scenario for future development of the network based only on the current visible trends in renewable and distributed generation. Although this was a necessary boundary to set a feasible scope for the thesis, it does mean that certain scenarios that could potentially have a significant impact on the proposed access arrangements have not been discussed.

For example, the scenario chosen excluded consideration of new nuclear build in the medium term future. Nuclear could be a low carbon option for the sustainable system, and one that would have significant implications for the transmission access questions raised in this analysis. Not only would the nuclear option change the scale of these discussions (current reactor designs can be as large as 1.6GW), but depending on their location could potentially alter some of the fundamental characteristics seen in the present transmission network. The recent Energy White Paper explored the possibilities of connecting new nuclear capacity in the south, far nearer the

demand centre of the system. This could change the north-south transmission power flow, and would clearly have implications for access arrangements throughout the system.

Alternative scenarios based on greater decentralisation of generation were also excluded. For example, scenarios in line with the proposal from the London Mayor to install 3GW of generation in the greater London area (PBPower, 2006, MoL, 2005), these decentralisation initiatives would site generation on the doorstep of the demand centres in the GB system. The outcomes and implications of a decentralised future located close to demand centres obviously focus attention on the distribution network access questions and again will challenge some of the assumptions and frameworks developed in this thesis.

- *Additional work could include exploration and development of new feasible scenarios based on larger and smaller scale low-carbon futures, and could highlight new questions for the access debate under these conditions.*

The low carbon agenda

Rather than an explicit exploration (or promotion) of a low carbon agenda, the focus of the research was on finding the most economically efficient solution to network access problems and resolution of network access issues to create a level playing field for all network users within the confines of the competitive market environment. These issues are not incompatible, but the former requires further analysis and exploration for its inclusion in the access debate.

The work presented here proposes a transmission access regime that will charge users of the network according to the costs that they impose. This has the implication that these price signals should encourage generation and demand to make optimal short and long term decisions on where to locate themselves on the network and when to access the network. However, the majority of large-scale renewable technologies are limited by the availability of primary energy resources as to where they can be sited. Wind resources in the UK are amongst the best in Europe, but they are positioned in the North of the land mass and beyond (on the Scottish Islands), a long way from the demand centres in the South-East. The proposed network access arrangements wouldn't necessarily discourage this development, but would price the network access required by renewables in Scotland according to the costs they impose on the network. The issue that this raises for the pricing of network access is encouraging the system to value the additional benefits that come from connection of renewable and low-carbon generation. The network is in place to ensure efficient and reliable transport of electricity from generator to consumer and to facilitate the competitive market allowing consumers to access cheaper

generation resources. For renewable generation in the North, the network also facilitates the connection of customers to remote low-carbon energy resources.

Direct promotion of low-carbon generation technologies was not an explicit aim of this research. Indeed, the aim of the work was to create a level playing field to allow equal consideration of all technology options. The market approach challenges the notion that all renewable or low carbon generation is "good" by virtue of simply having a reduced emission profile. Any new generation technology connecting to the network can increase pressure in an already congested system. For example, in the case of DG in Scotland which reduces local demand. The market based approach to network pricing, which reflects the impact of users on the network, will charge wind generation and DG connecting in Scotland relatively more than generation connecting elsewhere. However, this is simply reflecting the current priorities of network operation and development.

Markets can deliver a low-carbon power sector – but market design must reflect these priorities and commoditise externalities that can contribute to the alternative optimisation of the network that incorporates the low carbon agenda. Indeed, this is a key output from the recent Stern Review of Climate Change that called for urgent action on the continued development of carbon markets if the environmental impact of CO_2 emitting activities was to be taken seriously. Further explicit consideration of the carbon properties of generation technologies in this market framework would require additional research to explore the monetisation of current non-price goods (such as carbon). This is a non-trivial exercise, but would allow equal consideration of the value of low/no carbon generation alongside the other traditional factors considered in the optimisation of network access.

- *Additional work in this area could include exploration of the impact of valuation of carbon on the long term development of the networks.*

6.3.2 Suggestions for development of key findings

Building on the findings of the thesis, and notwithstanding the limitations of the approach explored in the previous section, there are also a number of avenues for further research that could continue to develop the themes of network access in a future sustainable power system. Three areas that would merit further work and discussion are outlined briefly below:

Quantitative studies to support proposed transmission access arrangements

The final chapters of this thesis proposed a new framework for enduring transmission access arrangements to support a system with high penetration of renewable and distributed generation.

The analysis included a qualitative evaluation of three options for development of access arrangements against a set of criteria/high level principles for optimality. To build on this initial qualitative assessment and advance the argument for or against any of these options the next stage in the analysis should be to undertake quantitative modelling of the findings on the GB system model and explore the sensitivities of any outcomes against key drivers.

Further work and quantitative studies to support the new framework for enduring access arrangements could include:

- *Sensitivity studies on the constraint costs of adding wind in Scotland without reinforcement*
- *Analysis of revenue streams and potential for market power etc. under alternative options for connection of new wind generation in Scotland and treatment of access (i.e. invest then connect, connect and manage and short term market for access).*
- *Evaluation of the potential for demand side involvement in constrained networks to utilise low marginal cost (intermittent and renewable) generation at times of peak output (high constraint costs, and low value to traditional demand centres). Identification of potential for local demand increases (and or fuel switching) in response to very low prices.*

Exploration of infrastructure investment options

The work carried out to date has not explored the various options for undertaking network investment, nor has it attempted to discuss the merits or otherwise of an (economically) optimally constrained network. Full realisation of the competitive market approach to network operation and development would indicate the approach of merchant transmission investment, however there are concerns that this approach is not sufficient to ensure that optimal network access is provided. The alternative is the current approach of the regulated monopoly requiring approval of all investment plans through the regulator.

The quote from (Helm, 2003) below illustrates some of the challenges open for debate in the long term network access field:

> *" [networks] are the motorways to the market, and over provision is greatly preferable to under provision. The optimal level of interconnection will not be developed by private vertically integrated oligopolists and their design and development have system-wide characteristics. An element of planning and a (heavy) dose of regulation is essential. It was a lucky coincidence that the market approach of the 1980s and 1990s was applied in the context of mature and well-invested electricity and gas networks. The assets could be sweated without worrying too much about the cost of capital or supply security. That luxury is no longer available, and hence the regulatory priority, and the appropriate instruments, need to shift towards investment." (Helm, 2003 pg. 422-423)*

There is a discussion to be developed on whether, as Helm speculates, over provision of networks is preferable for the good of the whole system, or if merchant transmission investment can in fact deliver optimal development and long term stability (Hogan, 1999). Or, indeed, whether merchant transmission investment can be effective against a backdrop of regulated monopoly network owner operators and semi-unbundled utilities (e.g. Brennan, 2006, Lyon, 2007). The current UK climate in which private investment drives most new infrastructure projects also colours the possibilities for future approaches to network investment. Projects with long term pay-back and multiple beneficiaries are not typically funded under the private investment model.

Further work in this area should scope the main issues in transmission investment relevant to the UK, this could include:

- *Exploration of the theoretical issues associated with approaches to transmission investment, access and pricing, including: separation of energy from access, merchant versus monopoly investment, financial versus physical transmission rights and evergreen property rights for transmission access.*
- *Review of the experiences of merchant transmission investment from markets elsewhere in the world.*

Enduring arrangements for distribution network access

In-depth development and analysis of future access arrangements for the distribution network was not a part of this research because it was out of the scope of the study. However, several areas of interest for further exploration were highlighted in the initial exploration of the distribution network access issues. In the short term there may be some merit in exploring the implications of recent changes to the distribution access arrangements that have come about through the revision of the Engineering Recommendation P 2/6, the distribution network security standard. P 2/6 makes allowance for the contribution that DG can make to securing load in the distribution network. As yet there have been no commercial arrangements to reward DG for this contribution, and the standard remains focused on security of supply for demand this raises several areas for further investigation, outlined in brief here:

- *Analysis of DG provision of non-network services in the context of risk of non-delivery of service against impact on quality of supply indicators (CIs and CMLs).*
- *Developing the business case and commercial arrangements for DG and demand side contribution to distribution network operation and security.*
- *Exploring the implications of generation driven security standards in the distribution network as well as demand driven. This is particularly pertinent with reference to the*

offshore transmission network bring power from offshore wind units into the onshore network at the distribution level. At transmission level generators are compensated if they cannot access the network, at distribution level there has been no provision made for generation.

References

ACE (1979) Report on the Application of Engineering Recommendation P2/5, Security of Supply. *ACE Report 51.* System Design and Development Committee of the Chief Engineers' Conference, Electricity Council.

AKHMATOV, V. & KNUDSEN, H. (2007) Large penetration of wind and dispersed generation into Danish power grid. *Electric Power Systems Research,* 77, 1228-1238.

ALLAN, R. & STRBAC, G. (2002) Network security standards with increasing levels of embedded generation.

ALLAN, R., STRBAC, G., DJAPIC, P. & JARRETT, K. (2004) Developing the P2/6 Methodology DTI New and Renewable Energy Programme.

AREVA (2006) Energy Management System Application for Large Windfarm Projects. *Fifth Intl. Workshop on large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms.* Glasgow, Scotland.

AWERBUCH, S., CARAYANNIS, E. G. & PRESTON, A. (1997) The Virtual Utility: Some Introductory Thoughts on Accounting, Learning and the Valuation of Radical Innovation. IN AWERBUCH, S. & PRESTON, A. (Eds.) *The Virtual Utility: Accounting, Technology & Competitive Aspects of the Emerging Industry.* Massachusetts, USA, Kluwer Academic Publishers.

AWERBUCH, S. & PRESTON, A. (1997) *The Virtual Utility: Accounting, Technology & Competitive Aspects of the Emerging Industry,* Massachusetts, USA, Kluwer Academic Publishers.

AWERBUCH, S. & SAUTER, R. (2004) Exploiting the Oil-GDP Effect to Support Renewables Deployment (Working Paper). SPRU, University of Sussex.

BAUGHMAN, M. L. (1997) Pricing of Open-Access Transmission Services in Texas. *Utilities Policy,* 6, 185-190.

BAUKNECHT, D. & LEPRICH, U. (2004) Development of Criteria, Guidelines and Rationales for Distribution Network Functionality and Regulation. part of the SUSTELNET project funded by the European Commission under the 5th RTD Framework Programme.

BAUKNECHT, D., LEPRICH, U., SPATH, P., SKYTTE, K. & ESNAULT, B. (2007) Regulating Innovation and Innovating Regulation. DG GRID, European Commission, Energy Intelligent Europe 2003-2006 Programme.

BILLINGTON, R. & ALLAN, R. (1984) *Reliability Evaluation of Power Systems,* New York and London, Plenum Press.

BILTON, M. J., RAMSAY, C., LEACH, M., DEVINE-WRIGHT, H., DEVINE-WRIGHT, P. & KIRSCHEN, D. S. (Forthcoming) Electricity Consumption and Demand Side Participation. IN GRUBB, M., JAMASB, T. & POLLITT, M. (Eds.) *Delivering a Low Carbon Electricity System: Technologies, Economics and Policy.* Cambridge, Cambridge University Press.

BITSCH, R. & KNOX, R. (2002) Integrating Diversity and Optimising Energy Use. *Renewable Energy 2002.* Sovereign Publications Limited.

BOITEUX, M. (1960) Peak-Load Pricing. *The Journal of Business,* 33, 22.

BORN, F. (2001) Aiding Renewable Energy Integration through Complementary Demand-Supply Matching. University of Strathclyde

BRENNAN, T. J. (2006) Alleged Transmission Inadequacy: Is Restructuring the Cure or the Cause? *The Electricity Journal,* 19, 42-51.

BUSHNELL, J. & OREN, S. (1997) Transmission Pricing in California's Proposed Electricity market. *Utilities Policy,* 6, 237-243.

BWEA (2007) www.bwea.com/offshore British Wind Energy Association Web Site (accessed Jan' 07).

CALDON, R., ROSSI, P. A. & TURRI, R. (2004) Optimal Control of al Distribution System with Virtual Power Plant. *Bulk Power System Dynamics and Control - VI.* Cortina d'Ampezzo, Italy.

CAO, D. M., PUDJIANTO, D., STRBAC, G., MARTIKAINEN, A., KARKKAINEN, S. & FARIN, J. (2006) Costs and Benefits of DG Connections to Grid System. DG GRID, European Commission, Energy Intelligent Europe 2003-2006 Programme.

CEC (2001) Green Paper: Towards a European Strategy for Security of Supply. Brussels, European Commission, Directorate-General for Energy and Transport

CEC (2006a) Directive 2006/32/EC of the European Parliament and of the Council of 5 April 2006 on energy end use efficiency and energy services and repealing Council Directive 93/76/EEC. Brussels, Council and Parliament of the European Commission.

CEC (2006b) European SmartGrids Technology Platform: Vision and Strategy for Europe's Electricity Networks of the Future. Brussels, Directorate-General for Research into Sustainable Energy Systems.

CEC (2007) An Energy Policy for Europe. Commission of the European Communities.

CONNOR, P. & MITCHELL, C. (2002) A Review of Four European Regulatory Systems and Their Impact on the Deployment of Distributed Generation. part of the SUSTELNET project funded by the European Commission under the 5th RTD Framework Programme.

CRISP (2006) Distributed Intelligence in Critical Infrastructures for Sustinable Power: Final Summary Report. CRISP Project, European Commission Funded under the EU-EESD programme.

DALE, L., MILBORROW, D., SLARK, R. & STRBAC, G. (2004) Total cost estimates for large-scale wind scenarios in UK. *Energy Policy,* 32, 1949-1956.

DATAMONITOR (2007) Smart Metering in the Energy and Utilities Sector. Datamonitor.

DETR (2000) Climate Change: The UK Programme. The Stationary Office, London, Department for Environment, Transport & the Regions (DETR)

DG&SEE (2007) www.sedg.ac.uk. Centre for Distributed Generation and Sustainable Electrical Energy.

DGCG (2003) First Annual report of the Distributed Generation Co-ordinating Group (2001/2002). London

DGCG (2004) Second Annual Report of the Distributed Generation Co-ordinating Group (2003). London

DGCG (2005) A Scoping Study: Demand Side Measures on the UK Electrical System. London, Department of Trade and Industry (DTI).

DIELMANN, K. & VAN DER VELDEN, A. (2003) Virtual Power Plants (VPPs) - A New Perspective for Energy Generation? *Modern Techniques and Technologies (MTT) 2003. Proc. 9th Int Scientific and Practical Conference of Students, Post-graduates and Young Scientists.*

DJAPIC, P., RAMSAY, C., PUDJIANTO, D., STRBAC, G., MUTALE, J., JENKINS, N. & ALLAN, R. (2007) Taking an Active Approach: Distribution System Transitions and Integration of Distributed Generation in Europe. *IEEE Power & Energy Magazine*, 68-78.

DTI (2003) Energy White Paper: Our Energy Future - Creating a Low Carbon Economy. The Stationary Office, London, Department for Trade & Industry, Department for Transport & Department for Environment, Food & Rural Affairs.

DTI (2006a) Digest of United Kingdom Energy Statistics. The Stationary Office, London, Department for Trade and Industry.

DTI (2006b) The Energy Challenge. London, Department for Trade and Industry.

DTI (2006c) JESS - Long Term Security of Energy Supply: December 2006 Report. Department for Trade and Industry, Joint Energy Security of Supply (JESS) Working Group.

DTI (2006d) Reducing the Cost of System Intermittency Using Demand Side Measures. London, Department for Trade and Industry (DTI).

DTI (2007) Meeting the Energy Challenge: A White Paper on Energy. The Stationary Office, London, Department for Trade and Industry.

DTI & OFGEM (2007) Review of Distributed Generation: A Joint Government/Ofgem Report. London, UK, Department for Trade and Industry & Office of Gas and Electricity Markets.

EAEA (2007) 50% Wind Power in Denmark in 2025 - English Summary. Copenhagen, Denmark, EA Energy Analyses.

ENCORP (2002) Virtual Power Plant: Multi Suite Dispatching Software. Colorado, USA, Encorp Intelligence

EPRI (2003) Electricity Sector Framework for the Future: Achieving the 21st Century Transformation. Palo Alto, California, Electricity Power Research Institute (EPRI).

EPRI (2004) The Integrated Energy and Communications Systems Architecture: Volume 1 - User Guidelines and Recommendations. Paolo Alto, California, Electricity Power Research Institute (EPRI).

FARMER, E. D., CORY, B. J. & PERERA, B. L. (1995) Optimal Pricing of Transmission and Distribution Services in Electricity Supply. *IEE Proceedings - Generation Transmission and Distribution,* 142, 1-8.

FAVRE-PERROD, P., GEIDL, M., KLOCK, B. & KOEPPEL, G. (2005) A vision of future energy networks. *Ieee Power Engineering Society Inaugural 2005 Conference and Exposition in Africa.*

GEIDL, M., KOEPPEL, G., FAVRE-PERROD, P., KLÖCKL, B., ANDERSSON, G. & FRÖHLICH, K. (2007) Energy Hubs for the Future. *IEEE Power & Energy Magazine,* 5, 24-30.

GOMEZ, T., RIVIER, J., FRIAS, P., ROPENUS, S., VAN DER WELLE, A. & BAUKNECHT, D. (2007) Guidelines for Improvement on the Short Term of Electricity Distribution Network Regulation for Enhancing Share of DG. part of the DG GRID Project, funded by the European Commission under the Intelligent Energy Europe Programme.

GREENPEACE (2005) Decentralising Power: An Energy Revolution for the 21st Century. London, Greenpeace.

GREGERSON, J. & MARIYAPPAN, J. (2001) Advances in Energy Control and Communication Systems. *The Distributed Energy Series.* Boulder, Colorado, E-Source.

GRENARD, S., PUDJIANTO, D. & STRBAC, G. (2005) Benefits of Active Management of the Distribution Network in the UK. *CIRED 18th Intl. Conf. on Electricity Distribution.* Turin, Italy.

GRUBB, M. (1988) On capacity credits and wind-load correlations in Britain: Simple statistical investigation of the correlations in historical data between wind and demand in Britain, and availability of wind power at peak demand times. *Proceedings of the 10th British Wind Energy Association Conference* London.

GRUBB, M. (1991) The Integration of Renewable Electricity Sources. *Energy Policy,* 19, 670-688.

HAWKES, A. & LEACH, M. (2007) The Capacity Credit of Micro Combined Heat and Power *ICEPT Working paper, http://www3.imperial.ac.uk/icept/publications/workingpapers.* London, Imperial College Centre for Energy Policy and Technology, Imperial College.

HELM, D. (2003) *Energy, the State and the Market: British Energy Policy Since 1979*, Oxford University Press, Oxford.

HOGAN, W. W. (1992) Contract Networks for Electric-Power Transmission. *Journal of Regulatory Economics,* 4, 211-242.

HOGAN, W. W. (1999) Market-Based Transmission Investments and Competitive Electricity Markets. Cambridge, Massachusetts, Centre for Business and Government, Harvard University.

HOL (Ed.) (2005) *2nd Report of session 2005/2006 - Energy Efficiency Volume II, Evidence,* London, HMSO.

HOLTTINEN, H. (2004) The impact of large scale wind power production on the Nordic electricity system". *Department of Engineering, Physics and Mathematics.* Helsinki, Helsinki University of Technology.

IEA (2002) Security of Supply in Electricity Markets: Evidence & Policy Issues. Paris, France, International Energy Agency (IEA).

IEA (2007a) Energy Security and Climate Policy: Assessing Interactions. Paris, France, International Energy Agency.

IEA (2007b) Tackling Investment Challenges in Power Generation. Paris, France, International Energy Agency.

ILEX (2001) The consolidation of small generators under NETA: A scoping study. London, Department of Trade and Industry.

ILEX (2002) Transmission Access: Defining Alternative Models. Ilex Energy.

ILEX (2005) The Tradeable Value of Distributed Generation. London, Department of Trade and Industry.

ILEX & STRBAC, G. (2002) Quantifying the System Costs of Additional Renewables. London, Department for Trade and Industry.

ILEX & UMIST (2004) Ancillary Service Provision from Distributed Generation. London, Department for Trade and Industry.

ILIC, M., BLACK, J. W. & PRICA, M. (2007) Distributed electric power systems of the future: Institutional and technological drivers for near-optimal performance. *Electric Power Systems Research,* 77, 1160-1177.

ILIC, M., YOON, T. Y., ZOBAIN, A. & PARAVABS, M. E. (1997) Toward Regional Transmission Provision and its Pricing in New England. *Utilities Policy,* 6, 245-256.

JENKINS, N. (1995) Photovoltaic Systems for Small-Scale Remote Power-Supplies. *Power Engineering Journal,* 9, 89-96.

JENKINS, N., STRBAC, G. & GREEN, T. (2006) Future Network Technologies: a report to DTI. London & Manchester, Imperial College London & University of Manchester.

KEMA-XENERGY (2004) Intermittent Wind Generation: Summary Report on Grid System Operations. KEMA-XENERGY for California Energy Commission.

LAMPADITOU, E. & LEACH, M. (2004) Risk Management for Small Generators Through Consolidation Services.

LI, F., TOLLEY, D., PADHY, N. P. & WANG, J. (2005) Network Benefits from Introducing an Economic Methodology for Distribution Charging. Department of Electronic and Electrical Engineering, University of Bath.

LOPES, J. A. P., HATZIARGYRIOU, N., MUTALE, J., DJAPIC, P. & JENKINS, N. (2007) Integrating distributed generation into electric power systems: A review of drivers, challenges and opportunities. *Electric Power Systems Research,* 77, 1189-1203.

LOVINS, A., DATTA, E. K., FEILER, T., R BAGO, K. R., SWISHER, J. N., LEHMANN, A. & WICKER, K. (2002) *Small is Profitable: The hidden benefits of making electrical resources the right size,* Snowmass, Colorado, USA, Rocky Mountain Institute.

LYON, T. P. (2007) Why Rate-of-Return Adders Are Unlikely to Increase Transmission Investment. *The Electricity Journal,* 20, 48-55.

MARNAY, C., BLANCO, R., HAMACHI, K. S., KAWANN, C., OSBORNE, J. & RUBIO, F. J. (2000) Integrated Assessment of Dispersed Energy Resources Deployment. Lawrence Berkeley National Laboratory, CA, USA., Consortium for Electric Reliability Technology Solutions (CERTS), Lawrence Berkley National Laboratory.

MILBORROW, D. (2003) PIU Working Paper on Penalties for Intermittent Sources of Energy. London, Performance and Innovation Unit (PIU), Cabinet Office.

MOL (2005) The Green Light to Clean Power: The Mayor's Energy Strategy. London, Mayor of London, Greater London Authority.

MOTTMACDONALD (2003) The Carbon Trust & DTI Renewables Network Impact Study Annex 4: Intermittency Literature Survey and Roadmap. London, The Carbon Trust and Department of Trade and Industry.

NGET (2004) GB Security and Quality of Supply Standard, Version 1.0. National Grid Electricity Transmission.

NGET (2005a) Enduring Charging Arrangements for Distributed Generation: Response to Ofgem Discussion Document September 2005. National Grid Electricity Transmission.

NGET (2005b) Great Britain Seven Year Statement. National Grid Electricity Transmission (NGET).

NGET (2006) Ancillary Services Procurement Guildelines. National Grid Electricity Transmission (NGET).

NGET (2007a) Great Britain Seven Year Statement. National Grid Electricity Transmission (NGET).

NGET (2007b) Open Letter on the Management of the GB Queue. National Grid Electricity Transmission.

NGET (2007c) Transmission Access Standing Group Terms of Reference (Issue 2) Paper to April 2007 CUSC Panel. National Grid Electricity Transmission.

OFGEM (1999) The New Electricity Trading Arrangements. London, Office of Gas and Electricity Markets.

OFGEM (2001) Report to the DTI on the Review of the Impact of NETA on Smaller Generators. London, Office of Gas & Electricity Markets (OFGEM)

OFGEM (2003a) Electricity Distribution Losses, a Consultation report. Office of Gas and Electricity Markets.

OFGEM (2003b) Small Generator Issues under BETTA - A Consultation Document. London, Office of Gas and Electricity Markets (OFGEM)

OFGEM (2004a) Distributed Generation Incentive, Innovation Funding Incentive, Registered Power Zones: Regulatory Instructions and Guidance. Office of Gas and Electricity Markets.

OFGEM (2004b) Electricity Distribution Price Control Review: Appendix - The Losses Incentive and Quality of Service. Office of Gas and Electricity Markets.

OFGEM (2005a) Enduring transmission charging arrangements for Distributed Generation: A Discussion Document. London, Office of Gas and Electricity Markets.

OFGEM (2005b) Further Details of the RPZ Scheme. London, Office of Gas and Electricity Markets (Ofgem).

OFGEM (2005c) Household Energy Bills Explained: Factsheet 52. London, Office of Gas and Electricity Markets.

OFGEM (2006a) Domestic Metering Innovation - Next Steps. Office for Gas and Electricity Markets.

OFGEM (2006b) Enduring Transmission Arrangements for Distributed Generation: Further Thoughts Document. *Further Thoughts Document.* London, Office of Gas & Electricity Markets.

OFGEM (2007a) Electricity Distribution Cost Reviews 2005-2006. London, Office of Gas and Electricity Markets.

OFGEM (2007b) http://www.ofgem.gov.uk/Networks/Trans/Offshore/Pages/Offshore.aspx. Office of Gas and Electricity Markets.

OFGEM & DBERR (2007) Transmission Access Review (TAR) - Open Letter to Industry. Office for Gas and Electricity Markets and Department for Business, Enterprise and Regulatory Reform.

OFGEM & DTI (2004) Small Generator Issues under BETTA - An Ofgem/DTI Conclusions Document.

OSWALD (2006) Effects of 20GW of distributed wind on the UK electricity system: An engineering assessment carried out for the Renewable Energy Foundation. Oswald Consulting.

PATTERSON, W. (1999) *Transforming Electricity,* London, The Royal Institute of International Affairs.

PATTERSON, W. (2003) Keeping the Lights on: Working Paper 2 - Generating Change. Chatham House, London, UK, Sustainable Development Programme, Royal Institute of International Affairs.

PATTERSON, W. (2004) Keeping the Lights on: Working Paper 3 - Networking Change. Chatham House, London. UK, Sustainable Development Programme, Royal Institute of International Affairs.

PBPOWER (2006) Powering London into the 21st Century. London, Mayor of London & Greenpeace.

PLATTS (2004) Harz develops virtual peak lopper. *Power in Europe.*

PLATTS (2005) Saar Targets Balancing Market. *Power in Europe*, 16.

PUDJIANTO, D., RAMSAY, C. & STRBAC, G. (2007) Virtual power plant and system integration of distributed energy resources. *Renewable Power Generation, IET,* 1, 10-16.

RAMSAY, C. & LEACH, M. (2005) Can Virtual Utilities Revive the Consolidation Market? *BIEE Academic Conference: European Energy - Synergies and Conflicts* St. Johns College, Oxford University, British Institute of Energy Economics.

RAOE (2003) Response to the House of Lords Science and Technology Select Committee Inquiry into the Practicalities of Developing Renewable Energy. *House of Lords Science and Technology Select Committee.* London, Royal Academy of Engineering.

READ, E. G. (1997) Transmission Pricing in New Zealand. *Utilities Policy,* 6, 227-234.

SAARENERGIE (2004) Virtual Power Plant Ensures Optimum Energy Mix. *Energy and Sustainable Development Magazine.*

SCHEEPERS, M. & WALS, A. (2003) New Approach in Electricity Network Regulation: An Issue of Effective Integration of Distributed Generation of Electricity Supply Systems. part of the SUSTELNET project funded by the European Commission under the 5th RTD Framework Programme.

SCHWEPPE, F., CARAMINIS, M., TABORS, R. & BOHN, R. (1988) *Spot Pricing of Electricity,* Massachusetts, USA, Kulwer Academic Publishers.

SHAFIU, A., BOPP, T., CHILVERS, I., STRBAC, G., JENKINS, N. & LI, H. Y. (2004) Active management and protection of distribution networks with distributed generation. *2004 Ieee Power Engineering Society General Meeting, Vols 1 and 2.*

SHULTZ, C., RODER, G. & KURRAT, M. (2005) Virtual Power Plants with Combine Heat and Power Micro-Units. *Future Power Systems, Intl. Conf.*

SINDEN, G. (2005) Wind Power and the UK Resource. London, Environmental Change Institute, University of Oxford for Department of Trade and Industry.

SKM (2004) Technical Evaluation of Transmission Network Reinforcement Expenditure Proposals by Licensees in Great Britain. Sinclair Kinght Merz, report for Office of the Gas and Electricity Markets (Ofgem).

SKM (2007) Long Term Capital Expenditure Forecasts for the Electricity Networks in Great Britain. Sinclair Knight Merz (SKM), for Energy Network Association (ENA).

STERN, N. (2006) The Stern Review: The Economics of Climate Change. London, HM Treasury.

STRBAC, G. (2006) Demand Side Management: Benefits and Challenges. *Foresight Programme, Sustainable Energy Management and the Built Environment Reports: Mini Energy Project.* Imperial College London.

STRBAC, G., JENKINS, N., GREEN, T. & PUDJIANTO, D. (2006) Review of Innovative Network Concepts. *DG-GRID, Research Project Supported by the European Commission, DG for Transport Energy and Networks.* London & Manchester, Imperial College & University of Manchester.

STRBAC, G. & MUTALE, J. (2006) Framework and Methodology for Pricing of Distribution Networks with Distributed Generation: a report to Ofgem. Manchester, Centre for Distributed Generation and Sustainable Energy.

STRBAC, G., MUTALE, J. & PUDJIANTO, D. (2005) Pricing of distribution networks with distributed generation. *2005 International Conference on Future Power Systems.*

STRBAC, G., PUDJIANTO, D., CASTRO, M., DJAPIC, P., STOJKOVSKA, B., RAMSAY, C. & ALLAN, R. (2007) Transmission Investment, Access and Pricing in Systems with Wind Generation. DTI Centre for Distributed Generation and Sustainable Electrical Energy.

TSO (1989) Electricity Act. The Stationary Office.

TSO (1998) Competition Act. The Stationary Office.

TSO (2000) Utilities Act. The Stationary Office.

TSO (2004) The Energy Act 2004. The Stationary Office.

TURVEY, R. (2005) Longer Term Electricity Distribution Charging Framework: A Report for Ofgem. London, Frontier Economics, for Office of Gas and Electricity Markets (OFGEM).

TUTTON, T. (2007) Adrift? Regulating Offshore Electricity Transmission Networks. *Oxera Agenda.*

UKERC (2006) The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network. London, UK Energy Research Council.

UN (1997) Report to the Conference of the Parties on its Third Session Held at Kyoto from the 1 to 11 December 1997. United Nations Framework Convention on Climate Change, United Nations

USDOE (2003) "Grid 2030" A National Vision for Electricity's Second 100 Years. Washington DC, USA, United States Department of Energy, Office of Electric Transmission and Distribution.

WILLEMS, B. (2004) Physical and Financial Virtual Power Plants. Leuven, Belgium, Catholic University of Leuven.

WU, X., MUTALE, J., JENKINS, N. & STRBAC, G. (2003) An Investigation of Network Splitting for Fault Level Reduction. Tyndall Centre for Climate Change Research.