SINCLAIR KNIGHT MERZ

GROWTH SCENARIOS FOR UK RENEWABLES GENERATION AND IMPLICATIONS FOR FUTURE DEVELOPMENTS AND OPERATION OF ELECTRICITY NETWORKS

BERR Publication URN 08/1021

June 2008

SINCLAIR KNIGHT MERZ

GROWTH SCENARIOS FOR UK RENEWABLES GENERATION AND IMPLICATIONS FOR FUTURE DEVELOPMENTS AND OPERATION OF ELECTRICITY NETWORKS

BERR Publication URN 08/1021
June 2008

Sinclair Knight Merz
13th Floor, Cale Cross House
156 Pilgrim Street
Newcastle upon Tyne
NE1 6SU
Tel: +44 (0191) 211 2400
Fax: +44 (0191) 211 2401
Web: www.skmconsulting.com

Contents

1 Executive Summary 1
1.1 Generation Background Scenarios 1
1.1.1 Conventional Plant 1
1.1.2 Renewables 1
1.1.3 Security of Supply 2
1.1.4 Generation Capacity for BERR Renewable Scenarios 2
1.2 Grid Operation and Expansion 3
1.2.1 Grid Operation 3
1.2.2 Network expansion and reinforcement 4
1.3 Costs and Benefits 5
1.3.1 Generation Investment costs 5
1.3.2 Grid Investment Costs 6
1.3.3 Benefits: Generation marginal costs, Carbon emissions and fuel diversity 7
1.3.4 Total costs 7
1.3.5 Conclusions 8
1.4 Other Issues 9
2 Introduction 11
2.1 Background 11
2.2 Objectives 12
2.3 Report Structure 12
3 Renewable target scenarios 14
3.1 EU and UK Renewable Targets 14
3.2 BERR Renewable Scenarios by sector 14
3.3 Electricity Demand in 2020 14
4 Generation Background 16
4.1 Introduction 16
4.2 Wind Generation 16
4.2.1 Onshore wind 16
4.2.2 Offshore Wind 19
4.2.3 Wind Capacity by 2020 22
4.2.4 Wind characteristics and its impact on the generation portfolio 24
4.2.5 Wind output modelling approach 24
4.2.6 Onshore and offshore wind generation load factors 25
4.2.7 Annual Wind Output 25
4.2.8 Seasonal wind characteristics 26
4.2.9 Capacity Credit 26
4.2.10 Responsive Plant 28

4.2.11 Curtailment 29
4.3 Other Renewable Generation 29
4.3.1 Biomass 29
4.3.2 Marine and Tidal 30
4.3.3 Total Renewable Generation Capacity 33
4.4 Conventional Plant 34
4.4.1 Security of Supply 34
4.4.2 Generation plant closures 34
4.4.3 New generation plant 35
4.4.4 Total Conventional Plant in 2020 35
4.5 Total Generation 36
5 Grid Connection 39
5.1 Overview and Summary of key findings 39
5.2 Background for Grid Connections 39
5.3 Generation connection technology 40
5.4 Generation connection planning 41
5.5 Generation connection charges 42
5.6 Offshore connection technology 42
5.7 Offshore generation connection costs. 45
5.8 Inter-array cabling 46
5.9 Offshore transformer platform 48
5.9.1 General 48
5.9.2 Export using ac cables 48
5.9.3 Export using HVDC 50
5.9.3.1 HVDC commercial issues 52
5.9.3.2 HVDC conversion losses 53
5.10 Export cable to shore. 53
5.10.1 Cable technology. 53
5.10.2 Cable capital costs and losses 56
5.10.3 Onshore transmission 57
5.10.4 Onshore grid connection 58
5.10.4.1 Import using ac cables 58
5.10.4.2 Import using HVDC 59
5.11 Comparison of alternative offshore connection arrangements 60
5.11.1 Dogger Bank and The Wash 61
5.11.2 Thames and North West 62
5.11.3 Wales 62
5.11.4 Dogger Bank versus Scottish Islands. 62
6 Main Interconnected System 64
6.1 Introduction and summary of findings 64

6.2 Operational Issues 65
6.2.1 Curtailment 65
6.2.2 Nuclear Generation 68
6.2.3 Wind and Nuclear curtailment alternatives. 70
6.2.4 Demand Control 70
6.2.5 International Interconnections 71
6.2.6 Intermittency 72
6.3 Onshore Reinforcements 73
6.3.1 Network conditions 74
6.3.2 Approach and Modelling 74
6.3.3 TIRG Reinforcements 76
6.3.4 Results 77
6.4 Regulatory Framework Considerations 79
7 Grid Costs 81
7.1 Introduction 81
7.2 Generation Costs 82
7.2.1 Variable costs 82
7.2.2 Fixed costs 84
7.2.3 Levelised costs of new plant 84
7.2.4 Generation investment costs 85
7.3 Generating Plant Output 86
7.3.1 Output 86
7.3.2 Load factor 87
7.3.3 CO_2 emissions 88
7.4 Generation cost 89
7.5 Balancing Costs 90
7.5.1 Short term balancing costs 90
7.5.2 Balancing plant enabling costs 90
7.6 Generation Connection costs 91
7.6.1 Offshore wind Generation 91
7.6.2 Onshore renewables 93
7.7 Total costs including grid costs 94
7.8 Conclusions 95
Appendix A Boundary Flows Analysis 96
A.1 High Wind, Peak Demand – Low Scenario 96
A.1.1 Available capacity 96
A.1.2 Modified dispatch 96
A.1.3 Boundary flow of original dispatch 96
A.1.4 Boundary flow of modified dispatch 97
A.2 High Wind, Peak Demand – Medium Scenario 97

A.2.1 Available capacity 97
A.2.2 Modified dispatch 97
A.2.3 Boundary flow of original dispatch 97
A.2.4 Boundary flow of modified dispatch 98
A.3 High Wind, Peak Demand – High Scenario 98
A.3.1 Available capacity 98
A.3.2 Modified dispatch 98
A.3.3 Boundary flow of original dispatch 98
A.3.4 Boundary flow of modified dispatch 99
A.4 Low Wind, Peak Demand – Low Scenario 99
A.4.1 Available capacity 99
A.4.2 Modified dispatch 99
A.4.3 Boundary flow of original dispatch 99
A.4.4 Boundary flow of modified dispatch 100
A.5 Low Wind, Peak Demand – Medium Scenario 100
A.5.1 Available capacity 100
A.5.2 Modified dispatch 100
A.5.3 Boundary flow of original dispatch 100
A.5.4 Boundary flow of modified dispatch 101
A.6 Low Wind, Peak Demand – High Scenario 101
A.6.1 Available capacity 101
A.6.2 Modified dispatch 101
A.6.3 Boundary flow of original dispatch 101
A.6.4 Boundary flow of modified dispatch 102

Appendix B Offshore connection costings 103

B.1 Connection Cost Summary – Low Scenario 103
B.1.1 Installed capacity and connection summary 103
B.1.2 Onshore connection with OHL 103
B.1.3 Onshore connection with UGC 103
B.2 Connection Cost Summary – Medium Scenario 104
B.2.1 Installed capacity and connection summary 104
B.2.2 Onshore connection with OHL 104
B.2.3 Onshore connection with UGC 104
B.3 Connection Cost Summary – High Scenario 105
B.3.1 Installed capacity and connection summary 105
B.3.2 Onshore connection with OHL 105
B.3.3 Onshore connection with UGC 105

Appendix C Wind Power Output Series 106

C.1 Offshore wind farms output record 106
C.1.1 Wind power station output analysis 106

C.1.2 The local wind resource. 106
C.1.3 Wind Turbine characteristics 110
C.1.4 Power output data series 111
C.2 Onshore wind farms output record 112
C.2.1 Scotland 112
C.2.2 England & Wales 116

1 Executive Summary

Three challenging renewable generation scenarios considered for the Electricity sector by 2020

Sinclair Knight Merz (SKM) was appointed by the Department for Business Enterprise and Regulatory Reform (BERR) to provide an initial high level assessment of the costs, benefits and issues to be addressed in accommodating high levels of renewable generation into the GB grid system. This report assesses three scenarios of renewable generation outlined by BERR – Lower, Middle and Higher renewables –amounting to about 35%, 40% and 50% respectively of the total electricity delivered in 2020 (currently about 5%). The scenarios reflect the growth in the contribution of renewable electricity generation that might be required to help the UK achieve its share of the 2020 EU target to deliver 20% of total energy consumption from renewable sources. This is an independent report and the views expressed herewith are of Sinclair Knight Merz.

1.1 Generation Background Scenarios

Demand by 2020 assumed to have no growth over current levels

In considering the amount of renewable generation capacity required to meet the renewable scenarios targets it is important to note that those targets are expressed relative to electricity demand in 2020. It has been assumed in this study that little demand growth over current levels will occur over the period to 2020 as all energy efficiency measures outlined in the Climate Change Plan will be fully implemented. A peak demand of 63.3 GW has been used for all scenarios corresponding to a total electricity demand delivered to the system of 374 TWh. The renewable scenarios – Lower, Middle and Higher renewables – consider an electricity sector in 2020 in which 127 TWh, 152 TWh and 186 TWh respectively of the total annual electricity delivered to the system is generated by renewable sources.

1.1.1 Conventional Plant

An assessment has been made in each scenario of conventional plant retirements by 2020 – including the coal-fired plant opted out of the Large Combustion Plant Directive and some nuclear plant. In all scenarios some 'New coal' plant is commissioned, together with two nuclear stations and various levels of CCGT plant.

1.1.2 Renewables

Wind Generation will produce 80% of the electricity generated from renewable sources by 2020

Following a review of current and expected future evolution of renewable generation technologies, costs, resource availability and supply chain constraints it was concluded that, given the relatively short time frame to 2020, most of the expansion in renewable generation will have to be based on wind generation (onshore and offshore) with some smaller amount of biomass based generation.

The majority of wind generation capacity by 2020 will be located offshore

The split between the onshore and offshore wind capacities required to meet the target was based on the maximum expected volume of installed onshore wind by 2020 (around 14 GW) with the rest of the required capacity to meet each of the renewable targets being sourced from offshore wind farms. The location of offshore wind generation is determined primarily by the combination of wind speed, distance from shore and depth of water but also takes into account other factors such as environmental issues, shipping lanes, oil and gas installations and many others. Offshore wind farm locations were selected firstly from suitable near shore sites and, following depletion of likely near shore areas, the balance of required capacity is sourced from Dogger Bank, an area of relatively low sea depth area with high average wind speeds some 170 km away from the Lincolnshire shoreline.

1.1.3 Security of Supply

Adequate levels of security of supply are maintained by 2020 with the indicated amounts of generating plant

A key consideration in establishing the amount of generation capacity required under each scenario is to ensure that an adequate level of security of supply against unplanned generation outages is maintained. One commonly used indicator of security of supply is the plant margin, the generation capacity above peak demand.

Although currently somewhat higher, a plant margin of 20% is commonly cited as an appropriate reference value for the GB grid, however this is based on a system dominated by large conventional plant which has both a high load factor and a more reliable output than wind. The variability of wind as a fuel source requires a certain proportion of wind generation capacity to be ‘backed up’ by conventional generation when the wind output is low.

Wind contribution to security of supply will only be15% of its capacity by 2020

A detailed analysis was undertaken to determine what proportion of the wind generation capacity could be assumed available to secure demand. This analysis produced three years of half hourly wind power output series from actual wind speed records of more than 50 locations on and offshore across GB. The results indicate that by 2020 the contribution of wind generation to security of supply under the *Higher scenario* will be about 15% of the total wind generation capacity.

Plant Margin is a misleading indicator of security of supply when comparing the current and 2020 systems

The relatively low load factor and the variability of wind generation means that it cannot replace conventional plant on a like for like basis and results in a significant increase in total installed capacity, an increasing requirement for the system to carry responsive plant, and a declining average conventional plant load factor. It can also be concluded that using plant margin as an indicator of security of supply when comparing a system with high wind penetration and a system based on conventional plant could be misleading.

1.1.4 Generation Capacity for BERR Renewable Scenarios

Table 1.1 shows the final generation capacity scenarios which maintain the security of supply equivalent to a conventional plant margin of 20%.

SKM

As renewables contribution increases, gas and coal fired plant utilisation reduces significantly by 2020

Table 1.1 Generation Scenarios, installed capacity and % of energy demand supplied

			Renewables Scenarios (2020)					
	2008		Lower		Middle		Higher	
Plant Type	GW	% Supply	GW	% Supply	GW	% Supply	GW	% Supply
Conventional Generation								
New coal	0.0	0.0%	3.7	6.9%	3.7	6.4%	3.7	5.8%
Coal	29.4	34%	18.3	13.2%	18.2	10.4%	16.9	7.1%
Gas	29.4	42%	29.3	26.3%	27.8	23.2%	27.3	19.7%
Nuclear	10.6	15%	6.0	11.5%	6.0	11.4%	6.0	11.0%
Interconnector	2.0	2%	3.3	6.8%	3.3	6.4%	3.3	5.4%
Other	9.6	2%	6.8	1.5%	6.8	1.5%	6.8	1.4%
Total Conventional	**80.9**	**95%**	**67.3**	**66%**	**65.8**	**59%**	**64.0**	**50%**
Renewable Generation								
Onshore wind	3.5	2.5%	11.5	7.5%	12.9	8.4%	14.3	9.3%
Offshore wind	0.2	0.05%	21.6	19.6%	25.7	24.2%	34.2	32.4%
Biomass	0.2	0.08%	2.2	5.7%	2.9	7.0%	3.3	7.2%
Other	2.2	2.4%	2.3	1.1%	2.3	0.9%	2.3	0.7%
Total Renewable	**6.1**	**5%**	**37.5**	**34%**	**43.8**	**41%**	**54.1**	**50%**
Total Capacity	**87.1**		**104.8**		**109.6**		**118.1**	

1.2 Grid Operation and Expansion

1.2.1 Grid Operation

No extra generation capacity will be required to cope with the variability of wind

The effects on grid operation of the large levels of wind generation required to achieve the renewable targets under each of the renewable scenarios was studied using half hourly wind output and demand series. The results indicate that the variability of wind when combined with the variability of demand will not impose any significant requirement for additional conventional generation capacity to provide frequency response however, a greater proportion of conventional plant will be called upon to provide that service and more frequently than at the present time.

Operation Costs to rise as 'back up' plant will increase payments in the Ancillary Services Market

The additional overall capacity required coupled with an increasing requirement for responsive plant results in a declining plant load factor – particularly of coal and gas-fired plant as shown in Table 1.1.

There is a physical limit to the amount of wind that the GB system can accept before wind output has to be curtailed at certain times

The ability of the system to absorb wind at all times was also investigated. The results indicate that in the Middle and Higher scenarios in particular there will be times when the wind generation output will exceed demand and wind will have to be curtailed. Curtailment will occur also at other times of low demand and high wind output as it becomes necessary to maintain a minimum amount of conventional plant running to provide frequency response and also certain plant of limited flexibility i.e. existing nuclear plant.

Exponential rise of wind curtailment with more than 39 GW of wind (Middle Scenario)

The amount of curtailment varies depending on the above issues and also the use of the pumped storage stations and interconnectors, however it rises exponentially from virtually negligible amounts in the *Lower scenario* to between 1.4 to 5 TWh in the *Higher scenario* depending on assumptions.

1.2.2 Network expansion and reinforcement

The impact of the new renewables generating capacity on the network has been investigated with reference to the expected capability of the transmission network by 2020 assuming that certain presently approved and planned reinforcements will have been commissioned. The study calculated the expected power flows across 17 critical system boundaries under the expected maximum wind output for both maximum and minimum demand conditions and compared those against the expected boundary capability under current GBSQSS rules.

Main Interconnected Transmission System may not require significant reinforcements over those already approved and planned

The results showed that the network may not require significant additional reinforcements provided that conventional plant flexes to allow access to wind generation. This is the desired effect; renewables displacing conventional generation. In addition it will also be necessary, particularly in the *Higher scenario*, for conventional plant in the north of GB to reduce its output while similar plant (by cost and technology) in the south subsequently increases its output with no additional overall economic cost.

The above result assumes also that offshore wind farms will connect to suitable points within the onshore network which are not necessarily the closest onshore transmission network point. This is a reasonable assumption as the offshore generation capacity in some areas is so large that it will not be practical to connect all the generation into a single closest onshore network point. In other cases the extension of the onshore section of the offshore wind farm connection could avoid some potential critical boundaries in the onshore network reducing the need for onshore network reinforcements at the expense of longer connections.

The network in the north and in Scotland will be close to limits and depending on assumptions some reinforcements may be justified. Costs are relatively small but some reinforcements may be subject to lengthy permitting.

Overall the most stressed area of the network was found in the north of the country and Scotland in particular, where some boundary margins, especially in the north of Scotland, were relatively marginal, even after redispatch of conventional generation. Some of these boundaries could therefore be quite sensitive to small increases in the amounts of renewable capacity or to the disposition of renewable capacity and certain onshore network reinforcements may be justified. Although in most cases the costs of these reinforcements are very modest compared to the costs of the offshore windfarm connection assets, some of the potential reinforcements identified in this report may be subject to lengthy permitting processes.

DC Submarine Transmission will be used for all those wind farms more than about 60 km offshore mainly Dogger Bank and the Round 3 projects in the Wash

The optimum characteristics of the connection assets for the significant amounts of offshore wind farm capacity have also been investigated. In particular the suitability of either AC or DC submarine transmission has been assessed and the suitability of either overhead or underground onshore continuations to appropriate connection points within the existing onshore grid.

The results indicate that, based on current costs of plant and equipment, for distances greater than around 60 km the use of DC submarine transmission will be economic over an AC alternative. As a result all the capacity in Dogger Bank will have to be connected using DC (with 1.2GW modules being the most economic) and possibly the majority of the Round 3 capacity in the Wash.

Underground cable is expected to be the bulk of the onshore part of the offshore wind farm connections to the main transmission system

For the onshore route section, it is considered that the more practical approach may be to use underground cable. While underground cabling is more costly than overhead lines it is considered that, given the relatively short time frame to 2020 and the uncertainty surrounding securing consent to construct overhead lines (as illustrated by Beauly-Denny and the resistance to more wind farms in several parts of the country), then underground cabling may be the most practical option unless substantial changes are introduced to the current planning and consenting requirements. In any case the large number of overhead lines routes that would be required (a minimum of 9 and 13 new overhead line routes for the low and high scenario respectively), indicates the likelihood of substantial undergrounding being required. Planning and consent issues may still influence underground cabling, particularly issues surrounding wayleaves over private land

Very Significant amounts of DC and AC submarine cable will be required to connect the offshore wind farms which will require expansion of manufacturers' production capacity

Notwithstanding the above onshore underground cable considerations, over 6,000 km of DC submarine cable will be required and around 1,900 km of AC 132 kV cable (depending on the scenario) which will represent a considerable manufacturing challenge.

1.3 Costs and Benefits

The adoption of the renewable targets has two major costs; the investment in new generation capacity and network assets, and delivers three major benefits; a reduction in the marginal cost of generation, an increase in fuel diversity and reduced dependency on foreign fuel sources, and a reduction in carbon emissions from the electricity sector.

1.3.1 Generation Investment costs

Generation investment costs amount to an extra £46 to £72 billion over a conventional scenario by 2020; the majority corresponding to wind generation

The total capital cost of the additional electricity generating capacity required by 2020 in the three scenarios is between £63 and £89 billion, as shown in Table 1.2), with most of the generation investment costs associated with offshore wind expansion[1]. In order to assess the comparative cost impact of potential renewable expansion we have also evaluated the costs associated with a generating system that remains dominated by conventional generation in 2020 with little new

[1] 2008 prices undiscounted

renewable investment – the Conventional scenario. The generation investment costs of the conventional scenario amount to around £17 billion by 2020.

Table 1.2 Generation Investment (£ billion, 2008 prices)

		Renewable Scenarios		
Technology	**Conventional**	**Lower**	**Middle**	**Higher**
Non-renewable generation				
New coal	3.9	3.9	3.9	3.9
CCGT	7.5	5.2	4.5	4.2
Nuclear	3.5	3.5	3.9	3.9
Total non-renewable	*14.9*	*12.6*	*12.3*	*12.0*
Renewable generation				
Onshore wind	0.4	7.1	8.5	9.6
Offshore wind	0.9	38.4	45.8	61.2
Biomass	0.0	3.6	4.9	5.6
other	1.0	1.0	1.0	1.0
Total renewable	*2.3*	*50.1*	*60.2*	*77.4*
Total generation	**17.2**	**62.7**	**72.5**	**89.4**

1.3.2 Grid Investment Costs

Grid investment costs total between £11 and £17 billion with the majority being the connection assets of offshore wind farms

In addition to the investment in new generation considerable investment in the existing UK electricity network will be required. We conclude that, depending on the scenario, the combined cost of the grid expansion and reinforcement amounts to up to between £10 to £17 billion over the period to 2020 – over half the modern equivalent replacement value of the entire existing transmission networks in GB. Of the total grid investment required the majority is for renewable connections with the majority of the remaining grid reinforcements including some already approved by Ofgem and planned but have yet to be completed which amount to circa £1bn.

Grid expansion costs for renewables represent up to about half of the Modern Equivalent Replacement Value of the entire transmission networks in GB

A significant proportion of the grid connection costs of renewables will be related to the offshore capacity in Dogger Bank

Table 1.3 Grid costs (2008 prices)

	Lower	**Middle**	**Higher**
Offshore Connection Cost with onshore OHL	£ 7.6 bn	£ 9.6 bn	£ 12.7 bn
Offshore Connection Cost with onshore UGC	£ 8.4bn	£ 10.6 bn	£ 14.1 bn
Other onshore Transmissions costs	£0.8bn	£0.8 bn	£0.8 bn
Distribution Costs	£1.0bn	£1.2 bn	£1.4 bn
Total Grid Costs	**£10.2 bn**	**£12.6 bn**	**£16.3 bn**

The offshore generation connections, including that component that is onshore, will be funded by the offshore wind developer. Depending on the nature of the connection arrangements some of the onshore connection assets may be regarded as part of the onshore or offshore transmission owner assets.

SKM

1.3.3 Benefits: Generation marginal costs, Carbon emissions and fuel diversity

Given that the marginal cost of generation is comprised largely of fuel costs, the marginal cost of generation is significantly lower in all the renewable scenarios (Table 1.4) than in the Conventional scenario, reflecting the displacement of gas and coal-fired electricity output by renewables..

Dependency on gas fired generation could reduce from about 42% currently to between 20% to 26% depending on the scenario

Table 1.4 Benefits of renewables

		Renewables Scenarios 2020		
	Conventional	Lower	Middle	Higher
Marginal costs (£/MWh)	35.9	25.0	22.6	18.9
Carbon Emissions (MtC)	44.3	28.3	24.3	19.4
Electricity supply %	2007			
gas	42%	26%	23%	20%
coal	34%	20%	17%	13%
nuclear	15%	12%	11%	11%
oil	1%	0%	0%	0%
interconnector	2%	7%	6%	5%
renewables	4%	34%	41%	50%
other	2%	2%	2%	1%

The increase in renewable generation results in a generation sector in 2020 whose source of fuel is more diverse than it is today. Table 1.4 shows the increase in diversity of electricity output. The use of gas as a fuel supply declines, arguably increasing security of supply given that most gas will be imported by 2020. The contribution of coal also declines, while the decline of nuclear is less marked due to the construction of two replacement plants.

1.3.4 Total costs

Diminishing returns for increased wind generation above about 39 GW (Middle scenario)

Table 1.5 shows the total costs associated with each scenario analysed. The total costs are a combination of marginal costs and investment costs. The total costs excluding grid are determined by calculating the lifetime levelised costs of each new plant type and combining these with the marginal costs of existing assets. The total costs include grid costs. The Middle scenario is the most cost effective renewables scenario, suggesting that, above a certain level of penetration, diminishing returns begin to set in with additional renewable investment.

Table 1.5 Annual Total Costs and Benefits by 2020, (2008 prices)

	Conventional	Renewable Scenarios Lower	Middle	Higher
New Generation capacity (£ billion)				
Renewable Capacity	2.3	50.1	60.2	77.4
Non- Renewable Capacity	14.9	12.6	12.3	12.0
Total	*17.2*	*62.7*	*72.5*	*89.4*
Network (£ billion)				
Offshore wind connection	0.0	8.4	10.6	14.1
Onshore wind connection	0.1	1.0	1.2	1.4
Other reinforcement	0.8	0.8	0.8	0.8
Total	*0.9*	*10.2*	*12.6*	*16.3*
Total Grid Investment Costs (Generation+network)	**18.1**	**72.9**	**85.1**	**105.7**
Marginal Generation cost	35.9	25.0	22.6	18.9
Cost per MWh produced (£/MWh)				
Generation costs (Fixed and variable)	46.8	51.9	52.6	54.5
Balancing and intermittency	1.7	6.3	7.2	8.7
Grid expansion for renewables	0.1	3.5	4.1	5.2
Total Cost including network (£/MWh)	**48.6**	**61.7**	**63.9**	**68.4**

Marginal generation cost will reduce significantly, from £36/MWh to between £25/MWh and £19/MWh depending on the scenario

1.3.5 Conclusions

- The total generation cost of an electricity system with significant renewable generation including associated grid expansion will cost at least 25 per cent more than a 'conventional' system.

Diminishing benefits and need for curtailing wind at certain times indicate optimum wind level for GB at about 40 GW

- A system with 40 per cent of electricity output supplied from renewables (*Middle scenario*), mainly offshore wind, will be marginally less costly than a system supplied with 34 per cent of output from renewables (*Lower scenario*). The difference is due to the reduction in fuel costs resulting from increased renewable generation output
- However, there are diminishing returns associated with increasing the renewable target beyond about 40 per cent (*Middle scenario*) as total costs begin to rise. This is also reflected by the need to begin 'curtailing' wind output at these levels of penetration because the system cannot physically accept, in some periods, all the output of wind and keep within adequate operating parameters.

The feasibility of the substantial increase in manufacturing capacity required to achieve the 2020 targets will be also dependant on the targets post-2020

- Given that there are diminishing returns associated with adding more wind capacity beyond about 39 GW there is a danger that the significant increase in industry capacity to meet the EU target by 2020, will become largely stranded until the time when the wind capacity begins to be replaced. For an offshore wind industry this could represent a cliff edge by 2020 unless alternative offshore developmental opportunities exist. In Europe and elsewhere these opportunities will be limited due to lack of suitable offshore wind locations and greater availability of onshore wind sites and other forms of renewable generation. This could have significant impact in the business incentives required to provide such industry capacity and the likelihood of meeting the target by 2020.

Dogger Bank development will require substantial capital investment and may require additional risk premiums to investors

- Furthermore, most of the capital costs of renewable investment are associated with developing offshore wind and the greatest costs are associated with wind farms in Dogger Bank. The magnitude of the investment required and the risks in developing such novel site with a long electrical connection will only be attractive to financially strong businesses which to commit to the projects may then require significant capital risk premiums, over those assumed in this study.

1.4 Other Issues

Although the grid reinforcement costs associated with accommodating renewables are relatively small compared to the grid expansion costs, our analysis is based on a number of key assumptions that, if altered, may increase grid reinforcement costs:

- An element of foresight is assumed when assessing the impact of emerging renewable generation on grid development
- The generation assumptions used in the network planning criteria of the GBSQSS are modified to account for the impact of intermittent generation particularly at times of peak demand. It should be noted that there is an industry process examining this issue and that some views of a revised approach to system planning may lead to higher levels of investment.
- Generation plant is dispatched on the basis of lowest short run marginal cost
- Potential congestion on the network is alleviated at least cost by the substitution of comparable generation – for example the reduction in output from a gas-fired plant due to network congestion is substituted by output from a gas-fired plant elsewhere on the network.

Assuming an element of foresight of renewable development over the period to 2020 ensures that uncertainty in grid development particularly to generation capacity location is minimised and hence leads to fairly optimal network development. In reality, over the interim period to 2020, renewable development may be more piecemeal. More piecemeal renewable generation may lead to higher grid reinforcement costs as conventional generation may only be 'displaced' when a certain capacity of renewable generation is reached. At lower levels of renewable capacity grid reinforcement may occur to accommodate the lower renewable capacity and the increasingly constrained existing conventional generation over the interim period to 2020.

Existing Transmission Network Planning Standard based on a system with dominant conventional plant will need to explicitly include wind generation and its treatment

The GB Security and Quality of Supply Standard (GBSQSS) for transmission network planning has been historically derived for a system with a dominant conventional generation plant mix with no provision for increasing volumes of wind generation. As a result the GBSQSS assumes conventional plant will operate at a relatively high load factor. Conventional thermal plant on a system with significant volumes of intermittent renewable generation will operate at a lower load factor. The average load factor of gas and coal-fired plant in the 'Conventional' scenario is over 50%, in the Higher renewables scenario it halves. Assuming that thermal plant operates at higher load factors, as in the existing GBSQSS, will lead to increased grid reinforcement requirements that may not necessarily be economic considering the long term network development. This is particularly applicable when considering the unprecedented change in the nature of the generation mix that could occur over the relatively short period to 2020.

Need to review assumptions under the GBSQSS to take into account wind generation and a longer view of system development

The ongoing Transmission Access Review (TAR) is revaluating how generation capacity, in particular renewable capacity, can access the transmission network, including the role of the constraint payment mechanism, potential sharing of transmission capacity, non firm access and the potential tradability of access rights. The TAR is timely and we conclude that:

- The validity of some of the generation background assumptions indicated in the deterministic planning criteria of the GBSQSS should be re-evaluated when applied to a system with large penetration of wind generation;
- The TAR should seek to introduce a transmission access regime that encourages a longer term developmental view of the transmission network, rather than attempting to accommodate increasing volumes of intermittent renewable generation on piecemeal and therefore more costly basis.
- In the case of long generation connections involving submarine cables (e.g. Scottish islands) substantial system benefits may be derived from connection to suitable network sites rather than the nearest network point. A review should also be undertaken of the commercial incentives for developers of costlier connection alternatives that may result in either reduced network reinforcements and/or reduced connection uncertainty. The current system dilutes costs signals of infrastructure assets (i.e. most onshore transmission assets) between consumers and generating parties and the existing locational signal may not provide sufficient incentives for developers (or indeed network owners) to pursue such connection arrangements.

Need to simplify and stream line the process of consenting new overhead line circuits

Finally and in addition to the above it will be necessary to simplify and shorten significantly the process to consent new overhead line circuits as recent experiences indicates that, even if additional reinforcements are justified, it will be almost impossible to get them built in time due to the complexities and duration involved in permitting new overhead line circuits.

2 Introduction

Electricity generation will play a large role in achieving the UK's share of the EU 2020 renewable energy target. Ensuring that the UK's electricity networks are fit for purpose and can accommodate the necessary growth in renewable variable, intermittent generation will be critical to the UK successfully meeting its share of the EU target.

Sinclair Knight Merz (SKM) was appointed by the Department for Business Enterprise and Regulatory Reform (BERR) to provide an initial high level assessment of the costs, benefits and issues to be addressed in accommodating high levels of renewable generation into the GB system. This report presents the results and findings of this work as well as recommendations.

2.1 Background

The Government's key energy policy objectives are to ensure secure, diverse and sustainable supplies of energy at competitive prices, and efficiency in energy use. In 2003 the Government set out four long-term goals for energy policy:

1) To put ourselves on a path to cut the UK's CO2 emissions by some 60% by about 2050, with real progress seen by 2020;
2) To maintain the reliability of energy supplies;
3) To promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity; and
4) To ensure that every home is adequately and affordably heated.

In delivering these policy objectives, the need to develop those sustainable technologies which will contribute to achieving increasingly rigorous and challenging environmental emissions and renewable energy targets (particularly in relation to combating climate change) is recognised, as is the finite nature of fossil fuel supplies.

The Energy White Paper 2007 set out the Government's international and domestic energy strategy to meet the long-term challenges we face in addressing climate change and ensuring security of energy supplies.

At the EU Spring Council of March 2007, the member states agreed to a number of targets aimed at tackling global climate change. One of these was the commitment for the EU to deliver 20% of its total energy consumption (i.e. electricity, heat and transport sectors) from renewable sources by 2020. Given that the renewable sources contribution at EU level is currently around 6% and in the UK 2%, this target is highly challenging.

On the basis of current policies (as set out in the 2007 Energy White Paper), it is expected that renewables will account for around 5% of UK energy consumption by 2020, but the new EU target will require the UK to now achieve a much higher proportion. The Prime Minister announced in November 2007 that the Government will develop a strategy to further increase the UK's use of renewable energy. This will involve a public consultation in 2008 and the publication of a new Renewable Energy Strategy in spring 2009 once the revised EU Renewables Directive has been agreed.

2.2 Objectives

The objectives of this work include the following:

1) The likely characteristics of the generation portfolio (i.e. all technologies including all forms of renewables, gas, coal, nuclear etc and storage), that will be needed to efficiently and securely deliver a level of renewables sufficient to meet our target;
2) What level of renewable generation the existing UK electricity network is;
    - capable of accommodating;
    - the changes, both physical and operational, that might be needed to the existing UK network for it to efficiently accommodate much higher levels of renewables whilst ensuring a secure supply, and
    - factors that may represent a barrier or constraint to timely delivery of the necessary changes.
3) Whether the existing conditions in terms of the technical, commercial and regulatory framework are sufficient to bring forward any changes needed to the network, both physical and operational, necessary to accommodate the necessary growth in renewables and if not why not.
4) The cost and feasibility of making the network suitable to support higher levels of renewables within the timescale up to 2020.

2.3 Report Structure

The structure of this report is as follows:

- Section 3 discussed three possible renewable target scenarios for the Electricity Sector
- Section 4 presents the impact on the renewable target scenarios on the 2020 generation background with particular emphasis on onshore/off shore wind.
- Section 5 examines the costs of connection of the levels of renewables indicated in Section 4 to the transmission and distribution networks in Great Britain
- Section 6 studies some operational issues arising from operating a system with a large penetration of wind generation and also the impact on the reinforcement requirements in

the transmission networks of Great Britain. Consideration is given to the barriers and changes required in the existing regulatory framework with particular emphasis on the planning, network access and infrastructure consenting and building issues.

- Section 7 includes a detailed assessment of the main costs and benefits of the proposed scenarios including an estimate of the impact on electricity prices by 2020.

This report also includes three Appendices with details of the network flows studies, system connection costs and details of the process undertaken to model onshore and offshore wind and to generate the wind power output series.

3 Renewable target scenarios

3.1 EU and UK Renewable Targets

In March 2007 the EU member states agreed to a number of targets aimed at tackling climate change. One of these targets was the commitment for the EU to deliver 20 per cent of its final energy demand[2] from renewable sources by 2020. The target allocated to each country varies across the EU recognising aspects such as the existing proportion of renewable sources in the energy mix of each country and also other aspects such as GDP and economic impact of achieving the 2020 target. Given that on the basis of current policies (as outlined in the 2007 Energy White Paper) it is expected that renewables will account for only around 5 per cent of UK energy consumption in 2020, the EU target will require the UK to achieve a much greater contribution from renewables. The EU target for the UK has been indicated as 15 per cent.

3.2 BERR Renewable Scenarios by sector

BERR considers that, as an important component of UK energy consumption, it is likely that electricity generation will play a large role in achieving the UK's share of the EU 2020 renewables targets. As a result three scenarios been proposed by BERR outlining a varying contribution of renewable electricity generation to help the UK achieve its share of the EU renewables target (Table 3.1). The scenarios – Lower, Middle and Higher renewables – consider an electricity sector in 2020 in which 127 TWh, 152 TWh and 186 TWh respectively of the total annual electricity delivered to the system is generated by renewable sources.

Table 3.1 BERR 2020 proportion of renewable scenarios by sector

Sector	*2020 Final Energy Demand (TWh)*	*2020 Renewable Scenarios*		
		Higher	Middle	Lower
Heat	625	6%	10%	14%
Road Transport	472	8%	10%	10%
Other Transport	246	0%	0%	0%
Electricity	**399**	**47%**	**38%**	**32%**
Total	1,742	15%	15%	15%

3.3 Electricity Demand in 2020

One of the key assumptions used in the renewable scenarios relates to BERR's assessment of electricity demand growth. BERR assumes that all the energy efficiency measures outlined in the Climate Change Plan[3] are fully implemented. As a result in all the 2020 renewable scenarios it is

[2] Final Energy Demand (FED). The precise definition of FED is still under discussion, however it is understood it includes transmission and distribution losses as well as energy for energy producing industry own use.

[3] http://www.defra.gov.uk/environment/climatechange/uk/ukccp/index.htm

assumed that electricity demand does not grow above current levels both in terms of energy (375 TWh) and also peak demand (63.3 GW).

4 Generation Background

4.1 Introduction

In order to determine the electricity network required to support the volume of additional renewable generation considered in each scenario, a suitable generation mix must be identified for 2020. Therefore the scenarios developed determine the characteristics of generation portfolios that are required to ensure that demand in 2020 is met, the renewables targets achieved and security of supply is acceptable. The scenarios are then used to evaluate the impact on the existing electricity network and determine any expansion and reinforcement that may be necessary to achieve the renewables targets for the electricity sector.

The total generation plant required to ensure that demand is met and security of supply is adequate in 2020 is determined by a generation dispatch model. The type of generating capacity dispatched by the model is a function of existing capacity, closures and commissioning plant assumptions over the period to 2020.

It should be noted that although this section presents the generation portfolio from a "target to required capacity" process, in reality the generation portfolio under each of the three renewable scenarios was the result of an iterative process as the renewables target is expressed in terms of energy and not capacity. Some of the assumptions made in this section are based on results which are further discussed in other sections.

Given the relatively short time frame to 2020, most of the expansion in renewable generation is assumed to consist of technologies that are already broadly market proven. As a result the increase in renewable generation required to meet the targets is expected to be largely provided by a combination of onshore wind and offshore wind, with an additional role for biomass. It is therefore important to evaluate the particular characteristics of renewables and wind generation in particular.

4.2 Wind Generation

As indicated above it is expected that, in order to achieve the Renewables Targets indicated in the three renewable target scenarios considered in this study, the majority of the required new renewable capacity will have to be based on wind generation technology. The following sections consider where the new capacity will be located and connected to the network, whether it will be onshore or offshore and some of its technical characteristics which may impact on the total generation capacity requirements.

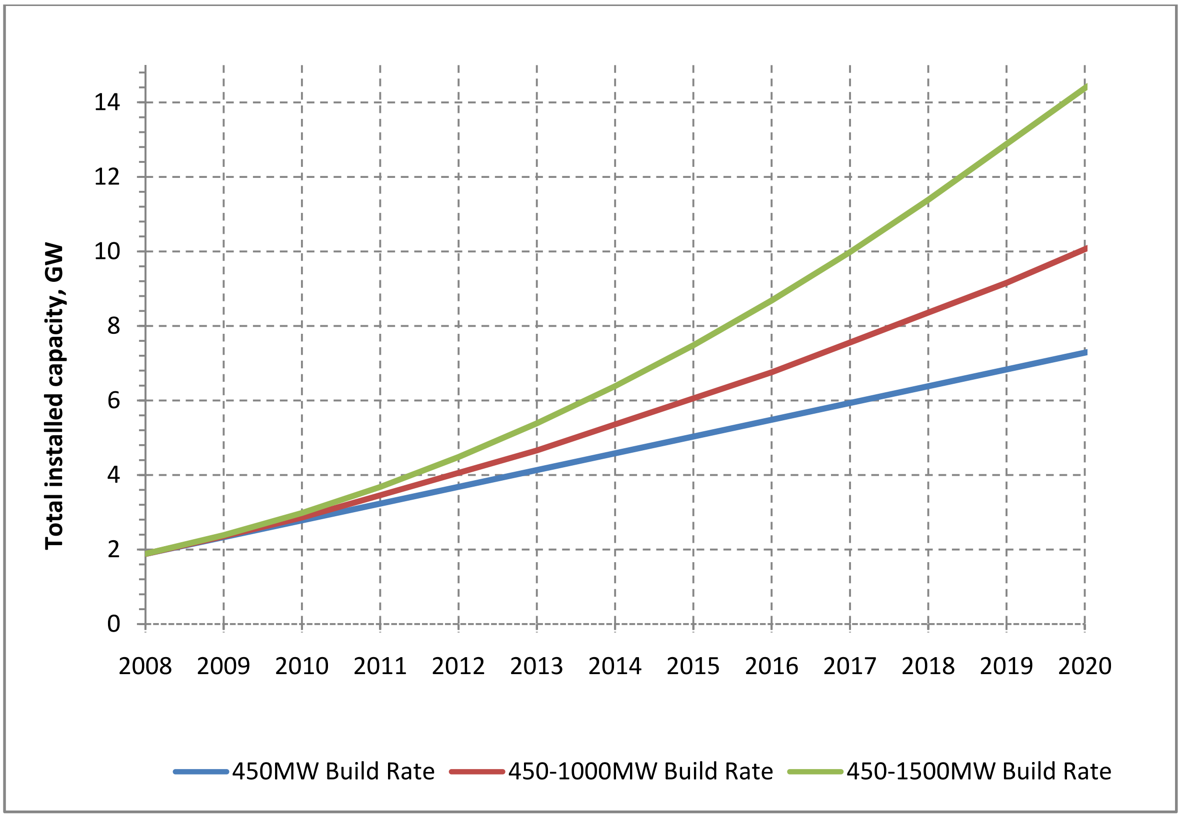
4.2.1 Onshore wind

Sinclair Knight Merz's June 2008 report for BERR "Quantifications of constraints on Growth of renewables" considered the various stages in the development process of onshore wind. Following a review of the historic submissions and approvals of planning applications and the issues surrounding the construction of consented wind farms, including the effects of the outcome of the Beauly-Denny Public Inquiry, a forecast was made for build rate and planning applications for the period to 2030.

In terms of assessing the market contribution of onshore wind – we consider that the development of onshore wind will be limited by suitable location – in particular consenting issues. Therefore, although onshore wind is more cost effective than offshore wind, the expansion of onshore wind will be limited by the availability and the opportunity to develop suitable sites.

Figure 4.1 shows the forecast cumulative installed capacity of onshore wind farms for the period to 2020 from the analysis in the above mentioned report. The forecast includes the results of three alternative build rates. It shows that by 2020 the maximum onshore capacity that is expected to be built would reach just over 14 GW.

Figure 4.1 Build scenarios for onshore wind farms

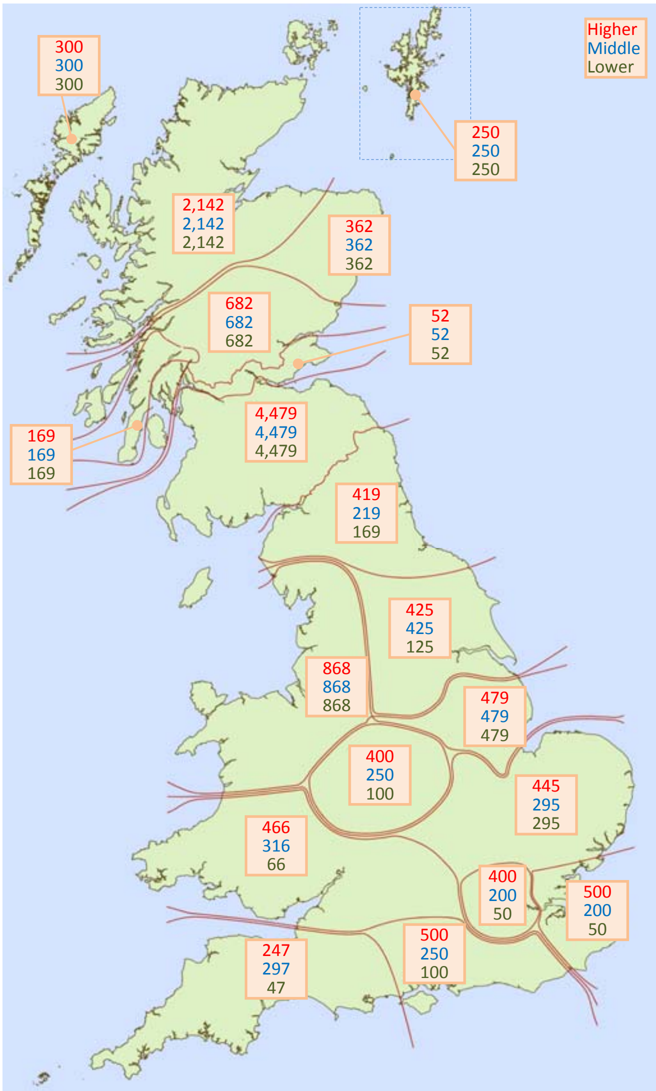


Based on the findings of the above report, in the *Lower scenario* we assume that most onshore wind currently in the development and planning pipeline is constructed – with a certain amount of repowering of existing sites. In the *Middle* and *Higher scenarios* an additional volume of onshore wind is constructed, reflecting increasing pressure to develop suitable sites, together with some repowering of existing sites. The amount of onshore renewable capacity assumed in each of the three 2020 renewable scenarios is summarised in Table 4.1 and distributed geographically as shown in Figure 4.2 for each renewable scenario closely based on existing and current planned developments as indicated in the NGT SYS. It is expected that the majority of the onshore wind capacity will be connected to the 132kV networks and below.

Table 4.1 Total Onshore Wind Capacity in 2020 (MW)

	2020 Renewable scenarios		
Plant Type	**Lower**	**Middle**	**Higher**
Onshore wind	11,474	12,924	14,274

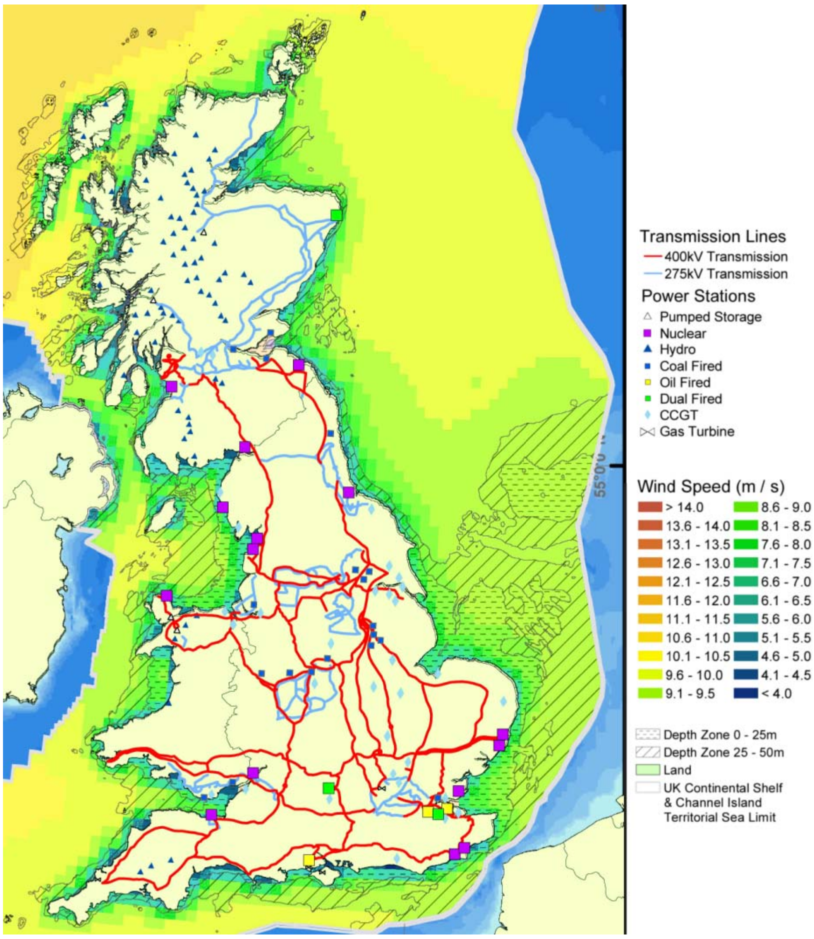
Figure 4.2 Assumed location of onshore capacity (MW)



4.2.2 Offshore Wind

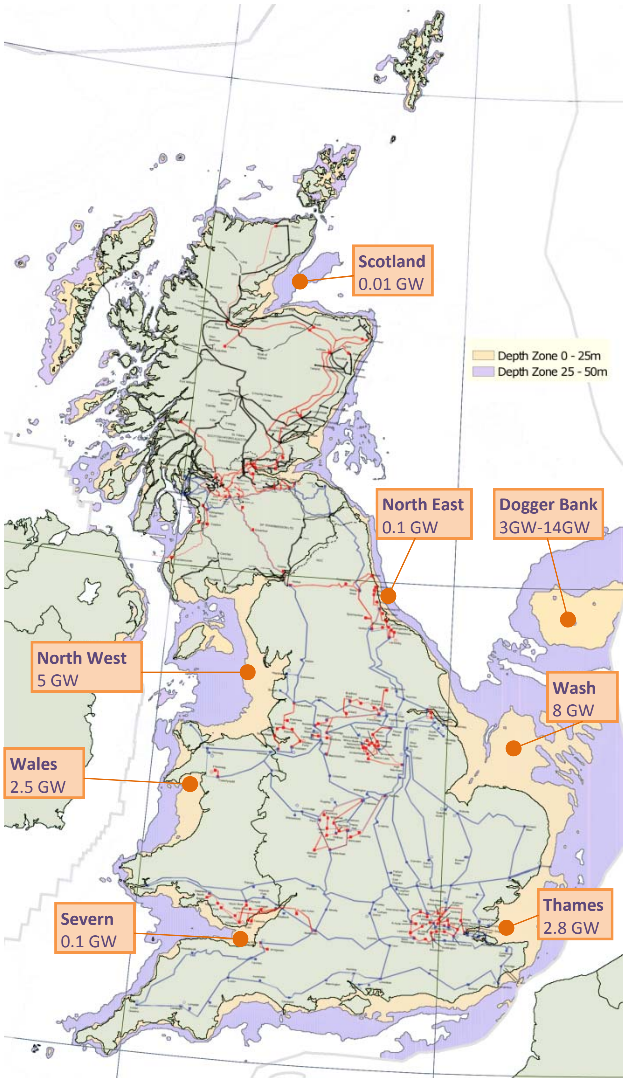
Given the constraints on the development of onshore wind and other renewables indicated in the above mentioned SKM report, a considerable expansion of offshore wind is required to achieve the renewable targets. The location of offshore wind generation is determined in the first instance by optimising a combination of wind speed, depth of water, distance from shore and proximity to suitable network connection points – with optimal sites close to the shore, in relatively shallow and characterised by relatively high wind speeds (Figure 4.3). A second iteration takes into account other factors that might constrain the development of an offshore wind farm, such as environmental issues, the existence of shipping lanes, MOD constraints and offshore oil and gas installations.

Figure 4.3 Offshore wind resource, sea depth and transmission network around GB



Based on the potential load factors of onshore and offshore wind and taking consideration of the volume of onshore wind as well as other renewables, the required volume of offshore wind under each renewable scenario was determined and iteratively refined to take into account of each of the selected sites potential capacity (Section 4.2.6). The remainder of this section describes the considerations made in the selection of the sites and potential capacity installed by 2020 under each of the scenarios.

Figure 4.4 Assumed location and capacities of offshore wind farms



Lower Scenario

With this Scenario 22.1 GW of offshore wind generation is assumed to be installed by 2020. To meet this requirement the installed capacities in the offshore regions are assumed to develop as follows:

1) *The Wash.* Round 1 + 2 developments in the Wash amount to about 4 GW and reference to Figure 4.3 indicates that further development could take place in the 20-25m sea depth areas further east of the existing Round 2 leases. On this basis it is estimated that a further 4 GW could be developed in the Wash.

2) *North West.* Round 1 + 2 developments in the North West amount to about 2.5 GW and reference to Figure 4.3 indicates that further development could take place in the 20-25m sea depth contours occupied by the existing Round 2 developments and possibly further offshore towards the Isle of Man. On this basis it is estimated that a further 2.5 GW could be developed in the North West.
3) *Thames.* Round 1 + 2 developments in the Thames region amount to about 2 GW and reference to Figure 4.3 indicates that further development would be somewhat constrained by the lack of suitable sites. However it is understood that the Greater Gabbard development that is committed to 500 MW has room for expansion to 1,000 MW. On this basis and on the assumption that a further 500 MW site can be found it is estimated that a further 1.3 GW could be developed in the Thames region.
4) *Severn.* Offshore wind development in the Severn region is limited to about 100 MW and reference to Figure 4.3 indicates that further development could be undertaken in the 20-25m sea depth areas off Weston-super-Mare. On basis that development in this area has not taken place it is assumed that there are significant environmental barriers and possibly technical difficulties due to the high tidal flow and tidal range within the Severn Estuary. Accordingly it is assumed that offshore wind development in the Severn region is limited to the existing 100 MW.
5) *North East.* Offshore wind development in the North East region is limited to about 90 MW and reference to Figure 4.3 indicates that there is little opportunity for further development in the 20-25m depth areas.
6) *Scotland.* Offshore wind development in Scotland comprises the 2x5 MW Beatrice demonstration project in 50m of water and further development in this area is not foreseen.
7) *Wales.* There are no existing offshore wind generation developments off the west coast of Wales but reference to Figure 4.3 indicates that there is a significant resource in the 20-25m depth area. The drawback on developments in this area is the absence of onshore electricity infrastructure on which to connect offshore wind generation. It is assumed that 2.5 GW can be developed off the west coast of Wales noting that connections to the shore may be more expensive than with some other options.
8) *Isle of Wight*. There are no existing offshore wind generation developments off the Isle of Wight although reference to Figure 4.3 indicates that there is a resource in the 20-25m depth area to the south east of the island. However this resource lies in an area of significant merchant shipping and naval activity and it is considered unlikely that significant developments will take place.
9) *Dogger Bank.* The Dogger Bank is a major potential resource located far offshore the North East coast as shown on Figure 4.4. It is assumed that there will be limited restrictions in

developing this area therefore it is assumed that the Dogger Bank will make up the balance of 3 GW to achieve the 2020 target of 22.1 GW.

Middle Scenario

In this scenario it is assumed that all regions apart from the Dogger Bank have been fully developed and that the Dogger Bank is developed to 7 GW to achieve the 2020 target of 26.2 GW.

Higher Scenario

In this scenario it is assumed that all regions apart from the Dogger Bank have been fully developed and that the Dogger Bank is developed to 14 GW to achieve the 2020 target of 33.7 GW.

The following table summarises the assumed offshore wind farm nominal capacities at the approximate geographical locations shown in Figure 4.4

Table 4.2 GB Offshore wind capacities and locations (MW)

		2020 Renewable Scenarios		
Region	**Round 1 + 2**	**Lower**	**Middle**	**Higher**
Wash	4,068	8,000	8,000	8,000
North West	2,588	5,000	5,000	5,000
Thames	1,954	2,800	2,800	2,800
Severn	108	108	108	108
North East	94	94	94	94
Scotland	10	10	10	10
Wales	0	2,500	2,500	2,500
Dogger Bank	0	3,600	7,700	15,200
Total	**8,822**	**22,112**	**26,212**	**33,712**

4.2.3 Wind Capacity by 2020

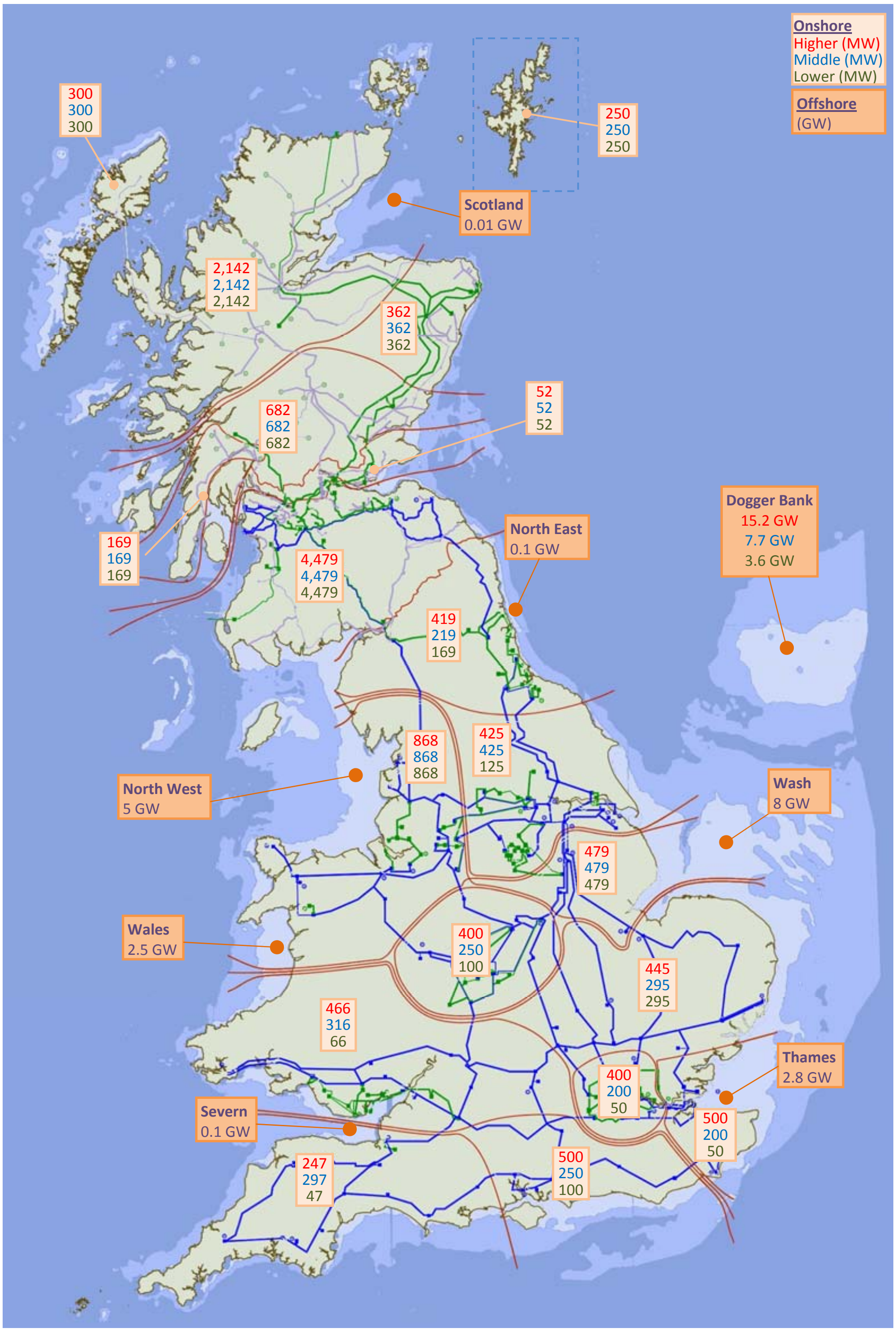
The following table shows the total amount of wind capacity, onshore and offshore, by 2020 under each of the renewable scenarios.

Table 4.3 Total wind capacity in 2020 (GW)

	2020 Renewable scenarios		
Plant Type	**Lower**	**Middle**	**Higher**
Onshore wind	11.5	12.9	14.2
Offshore wind	21.5	25.7	34.2[4]
Total	**33.0**	**38.6**	**48.4**

[4] A further 500 MW of offshore wind capacity was required to meet the target in this scenario to compensate for the energy loss due to curtailment (Section 4.2.11)

Figure 4.5 Assumed location of onshore and offshore capacity, and current GB transmission network (400kV -blue-, 275kV -green- and 132kV –purple Scotland only-)



4.2.4 Wind characteristics and its impact on the generation portfolio

Wind as an intermittent generation source may require additional plant to maintain network security. The considerable levels required to meet the targets under the renewable scenarios makes it necessary to consider the characteristics of wind generation and in particular:

- Energy contributions
- Capacity contribution
- Impact on reserve and frequency control
- Curtailment

The following sections examine these issues and its impact on the generation requirements.

4.2.5 Wind output modelling approach

Wind power is intermittent power source that follows the variability of weather conditions. In order to study the effects of large amounts of wind generation on the network a characteristic power output data series has been created which takes the following into account:

- The wind speed records at each of the likely development areas;
- The wind speed at the wind turbine hub height
- The characteristics of wind turbines (both onshore and offshore);
- The impact of aero dynamical losses and wind turbine reliability;
- The diversity effects within a wind farm and,
- The diversity effects of a multitude of wind farms within an area.

Three years of actual half hourly wind speed records from over 50 selected locations, both onshore and offshore across GB, have been numerically processed to consider the above issues and resulted in a synthesised half hourly wind power output. Half hourly wind power output series for onshore and offshore sites were combined to give an overall wind output record. The three year wind speed record was carefully selected to be representative of a ten year average wind speed and hence the three year wind output data series can be considered representative of a ten year wind output record.

The use of a half hourly wind output record allows the consideration of intermittency and seasonal and diurnal characteristics of wind and also allows the study of grid operational issues and diversity effects in the grid power flows.

A detailed description of the process undertaken and the assumptions made to obtain the wind power output record can be found in Appendix B.

4.2.6 Onshore and offshore wind generation load factors

The following table (Table 4.4) shows the resulting average annual load factors for onshore and offshore wind under the various 2020 renewable scenarios for the locations indicated in Section 4.2.2. The average onshore load factor is about 29% with larger values found in the north of Scotland and the Scottish islands in particular. The increase in the offshore load factor in the *Middle* and *Higher scenarios* is mainly the result of the increase capacity at Dogger Bank which has an estimated load factor of 49%.

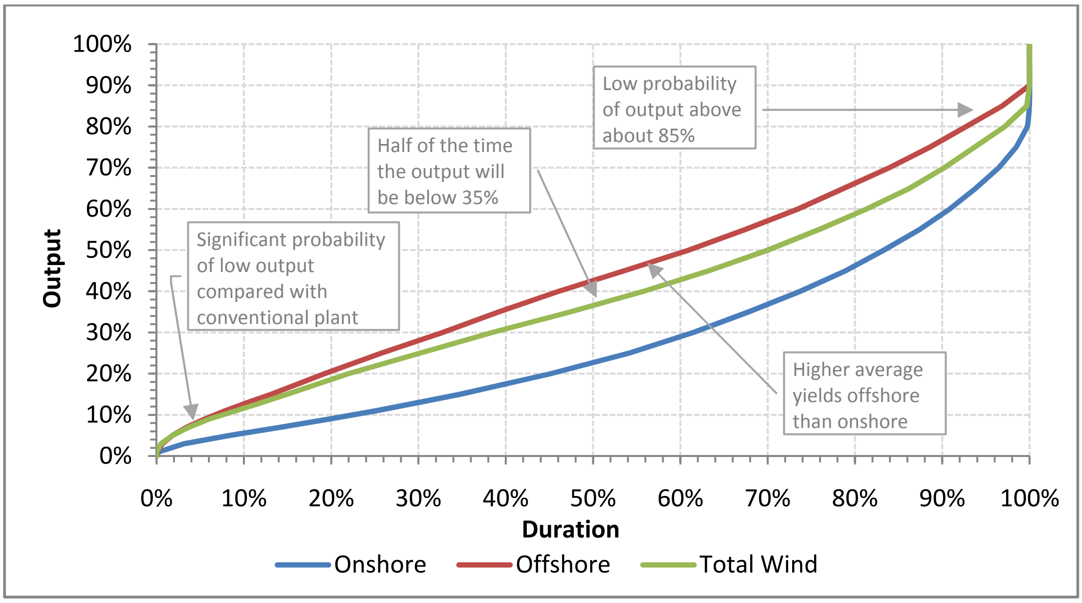
Table 4.4 Onshore and offshore wind generation load factors

	Renewable Scenarios 2020		
Type	**Lower**	**Middle**	**Higher**
Onshore	28%	28%	29%
Offshore	39%	40%	42%
Total	**35%**	**36%**	**38%**

4.2.7 Annual Wind Output

Figure 4.6 presents the annual distribution of wind output for the *Higher Scenario* and shows the effects of diversity in that outputs greater than 85% have very low probabilities. It also shows that for half of the time the output will be below 35% of the installed capacity. The higher yields from offshore wind over onshore wind are also evident with the offshore output-duration curve being considerably above the onshore.

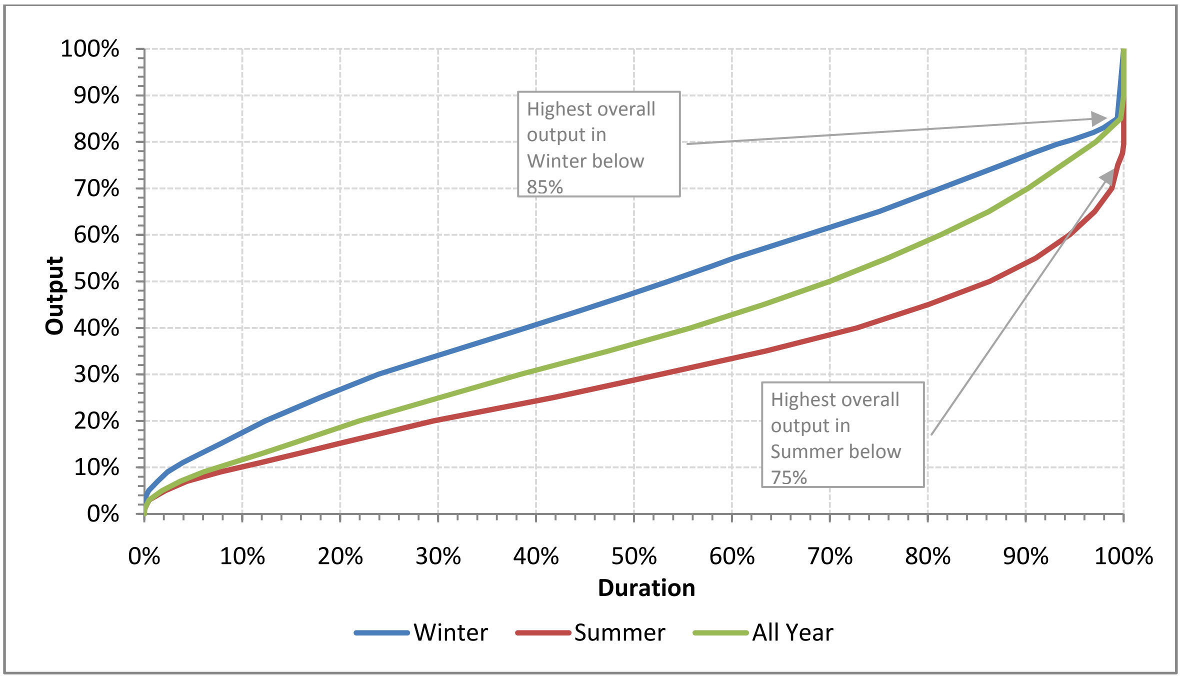
Figure 4.6 Annual wind power output-duration curve. Higher renewables scenario



4.2.8 Seasonal wind characteristics

Wind farm output in GB shows marked seasonal and daily characteristics. Figure 4.7 shows the statistical seasonal distributions extracted from the wind power output record discussed in Section 4.2.5.

Figure 4.7 Seasonal Wind Output Distribution (Higher scenario)



The seasonal distribution shown in Figure 4.7 also shows that the seasonal effects of diversity in the probability of high wind output. It indicates negligible probability of outputs higher than 85% in winter and 75% in summer.

4.2.9 Capacity Credit

The expected capacity contribution from wind generation to secure demand is lower relative to its nameplate rating than conventional plant due to the intermittent nature of its source. The calculation of the capacity contribution from wind generation to security of supply is normally undertaken by reference to a Loss-of-Load probability (LOLP) assessment where the output each generating unit within the whole generation portfolio is assessed probabilistically against the annual load duration curve to establish the probability that demand will exceed generation. When the assessment includes wind generation, the amount of conventional capacity that would be required to achieve the same LOLP value with and without wind generation can be calculated to determine the effective "capacity credit" of wind.

Given the time constraints associated with the production of this report a less time consuming process has been adopted to estimate the capacity credit of wind that it is believed produces a good approximation using a robust calculation methodology. The approach builds on the use of the three-year half hourly wind output series and examines the wind output at times of winter peak demand only when the contribution from the generation portfolio is critical to establish the need or otherwise for additional generation capacity. The results that have been obtained are in line with some of the reported findings in this area[5].

Figure 4.8 Distribution of wind output. Winter between 17:00 and 18:30. Higher scenario.

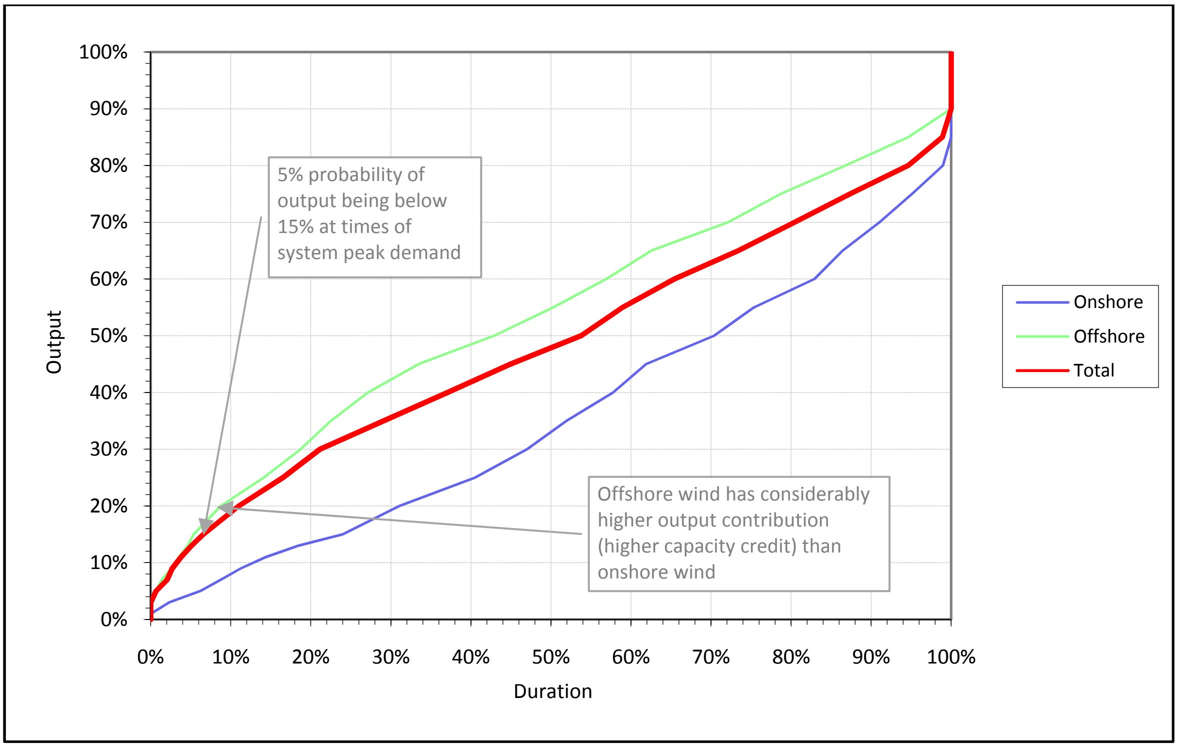


Figure 4.8 shows the distribution of wind output in winter at times of peak demand (typically between 17:00 and 18:30) for the *Higher Scenario*. It shows that the probability of having low wind output at times of peak demand is considerable. There is a 10% probability that wind output will be below about 20% of installed capacity at times of peak demand in winter and a 5% probability of output being below about 15%. This value has been taken as a measure of the capacity credit of wind or proportion of installed wind capacity that contributes to secure demand. This probability (5%), equivalent to once in 20 years, is taken as the capacity value of wind that can be relied on, for network planning purposes, at times of peak demand. It should be noted that

[5] "Wind Power has a Capacity Credit, a catalogue of 50+ supporting studies", Gregor Giebel, Risø National Laboratory, Denmark, 2005

the one-in-twenty years risk assessment criteria is consistent with the security of supply assessment criteria used by National Grid in their annual Winter Consultation Report albeit in this case used to evaluate the risk of a unusually high demand (severe winter).

It is also important to note that the capacity credit of wind is not a “fixed” value and varies with the amount of wind capacity installed and the wind characteristics. Generally the wind capacity credit will reduce with installed wind capacity as a result of the increased dominance of Dogger Bank and consequential reduction in the effects of geographic diversity. It is also important to note in Figure 4.8 the higher capacity credit of offshore wind than onshore wind resulting from the lower variability (and higher load factor) of offshore wind. The relatively low capacity credit of wind compared with conventional generation sources also confirms the primary nature of wind generation as an energy source and not as a capacity source in contrast to conventional generation plant with reliable fuel sources.

The intermittency of wind generation poses a challenge to balancing the system in real time given that electricity supply and demand must be balanced instantaneously. Continuous improvements in forecasting wind farms output forecast have resulted in currently available computer models that produce good accuracy short-term wind farm output predictions. However ‘back up’ plant is required to ensure the security of electricity supply at times of low wind output. The low capacity credit of wind presented above leads to a significant requirement for back –up conventional generation (Section 4.4) which results in increased total installed generation capacity in 2020 in all scenarios to ensure security of supply, albeit that the total amount of conventional generation will be reduced.

4.2.10 Responsive Plant

In addition to ensuring sufficient total capacity is installed to maintain security of supply, sufficient plant must be kept in responsive mode on the system at any one time in order to manage the short term variability of wind output in addition to the requirement to provide cover against the loss of a large conventional generation unit.

We have determined (Section 6.2.6) that the increasing volume of wind generation represented in the scenarios does not lead to a requirement to increase the installed non-renewable plant capacity in order to control wind power output fluctuations over and above that required to cope for the periods when wind output is low at times of high demand i.e. system security. However, the usage of non-renewable plant to cope with wind power fluctuations will increase both in terms of the amount of capacity required and how often they will be used with a subsequent impact on system operating costs. Section 7.4 quantifies the balancing costs on the total generation costs.

4.2.11 Curtailment

The potential variability of wind will require the system operator to maintain a proportion of flexible generation on the system to compensate for any variability in the wind resource. Given the inherent nature of its intermittent fuel source wind generation may need to be curtailed in favour of conventional generation so that the network is capable of:

- Frequency Control
- Reserve provision
- Voltage Control
- Load following

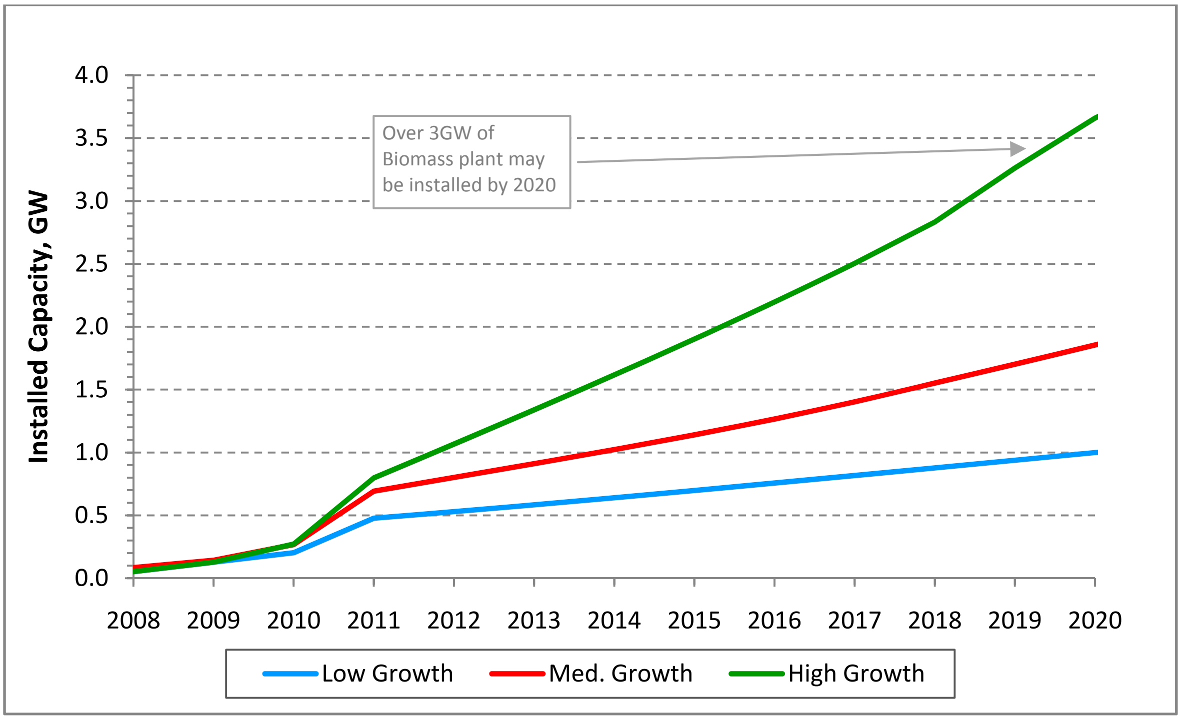
Our analysis (Section 6.2.1) indicates that curtailment begins to emerge in the Medium scenario and rises exponentially with greater volumes of wind generation accessing the network. In the *Higher scenario* curtailment of up to 5 TWh may occur. This leads to a requirement to increase the offshore wind capacity by about 500 MW to meet the target in the *Higher scenario*.

4.3 Other Renewable Generation

4.3.1 Biomass

The development of biomass is considered to be limited by the availability of a suitable fuel source. Figure 4.9 shows the summary of the build rate assumptions for biomass presented in SKM's May 2008 report for BERR "Quantification of Constraints of UK Renewable Generating Capacity". Given that the fuel source for biomass generating plant is relatively bulky and of low value, the proximity to a suitable fuel source for a new biomass generating station will be a key economic consideration. Suitable fuel source locations are limited in the UK, thereby limiting the development of biomass up to about 3 GW by 2020. However, in addition to the construction of new biomass plant we also assume that 5 per cent of output from coal-fired stations is generated from biomass fuel sources, with the fuel sourced either indigenously or, more commonly, from imports.

Figure 4.9 Biomass build rate scenarios (Regular, imported and energy crops)

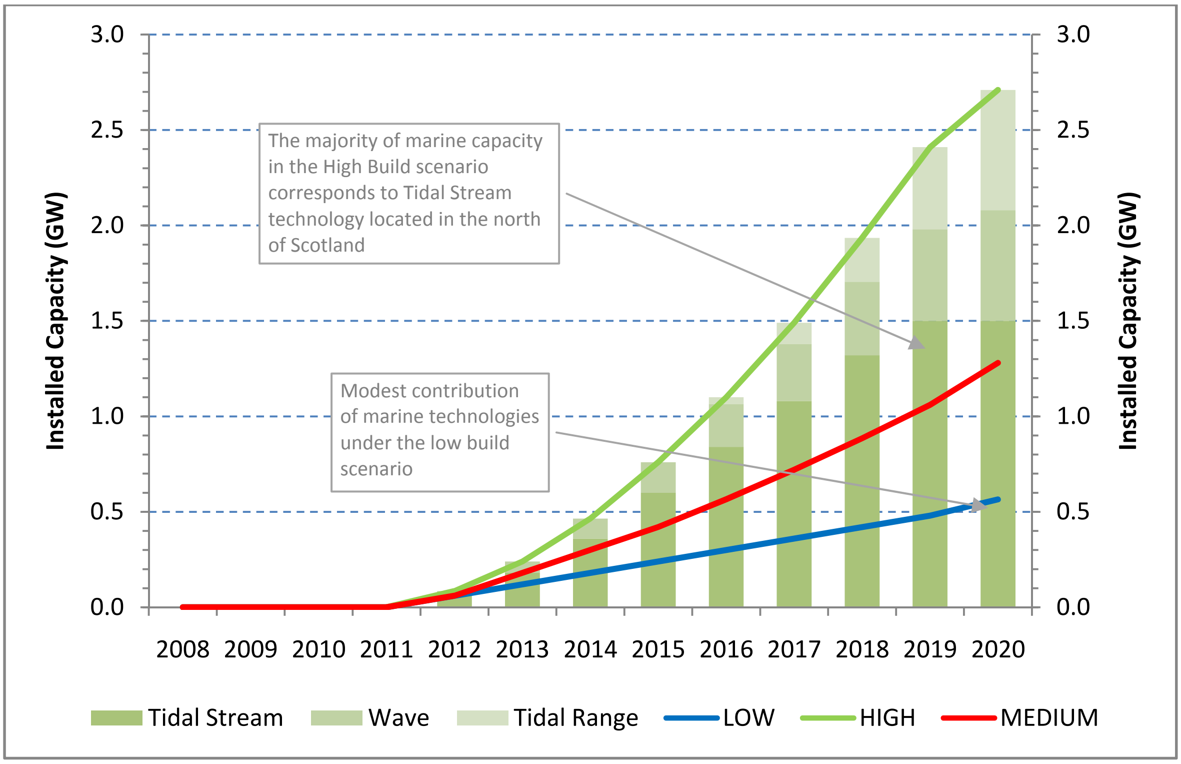


4.3.2 Marine and Tidal

The installed capacity forecast for wave and tidal technologies under three build rate scenarios presented in SKM's May 2008 report for BERR "Quantification of Constraints of UK Renewable Generating Capacity" is shown in Figure 4.10, which also shows for the High build rate scenario the break down between wave, tidal stream and tidal barrage. Although the potential plant that can be built by 2020 is indicated as 2.5 GW, following consideration of the technology development and the effects of potential known constraints, which have only been assessed at a high level, on the High build rate scenario, the Low build scenario has been selected as appropriate which does indicate a modest expansion of marine and tidal capacity by 2020. Overall it has been considered in the development of the scenarios that marine technologies remain at the prototype or early commercial stage and it is unlikely that, in the time frame considered, significant commercial market penetration will occur.

It is also important to note the dominant contribution of tidal stream to the total (Figure 4.10) particularly in the High build rate scenario (about 1.5 GW) and that the majority would be located in the Pentland Firth in the very north of Scotland. From a network infrastructure perspective the connection of such amount of capacity in addition to the onshore wind capacity indicated in Section 4.2.1 could result in the need for network reinforcement. Although a very modest contribution from tidal stream has been assumed in the 2020 renewables scenarios for the reasons indicated above, the consequences of assuming a higher tidal stream capacity contribution in the network by 2020 are further considered in Section 6.3.

Figure 4.10 Marine Technologies; wave, tidal stream and tidal range



Given the large scale and significance of the Severn barrage within all the proposed marine technology projects, additional detailed modelling was undertaken to establish the possible operational impact of such project within a GB system with considerable wind penetration as assumed in the three 2020 renewable scenarios. The study used actual sea level records from the Hinckley Point in the Severn Estuary area to model the tidal fluctuations. The records comprised 15 minute average level data for a year. This data was then processed to model some of the possible operation modes indicated for the Severn Barrage[6].

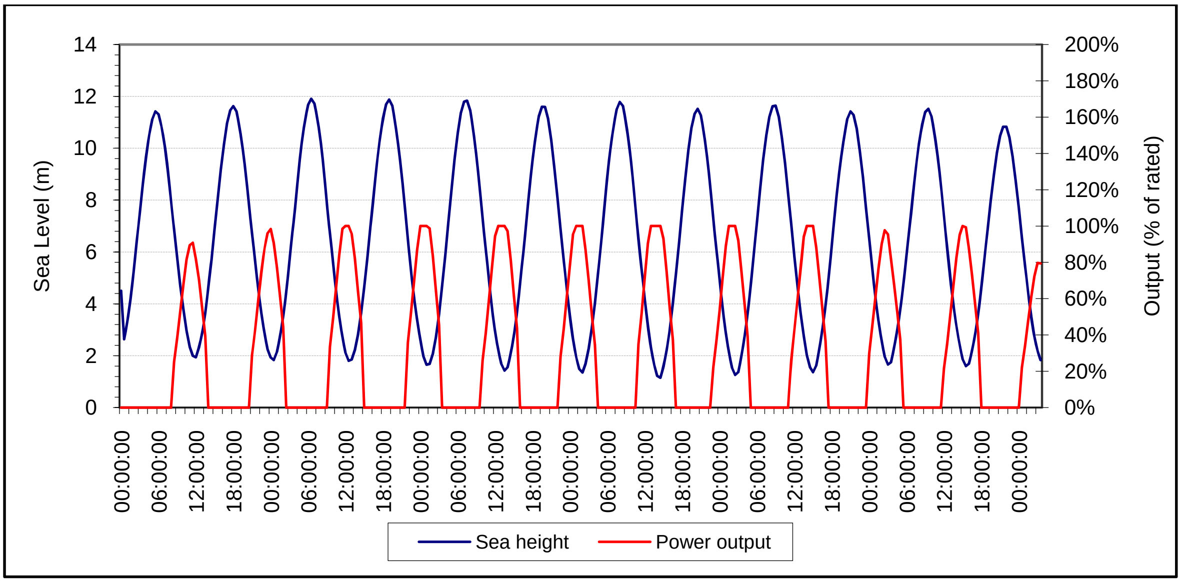
Figure 4.11 shows a snapshot of the model output over a few days showing the relation between tides and power output. In order to maximise energy yields from the barrage, the mode of operation should cycle from periods of no output, to periods of high output maximising the height difference

---

[6] Sustainable Development Commission Tidal Power Project, "Tidal Power in the UK", October 2007. www.sd-commission.org.uk/pages/tidal.html

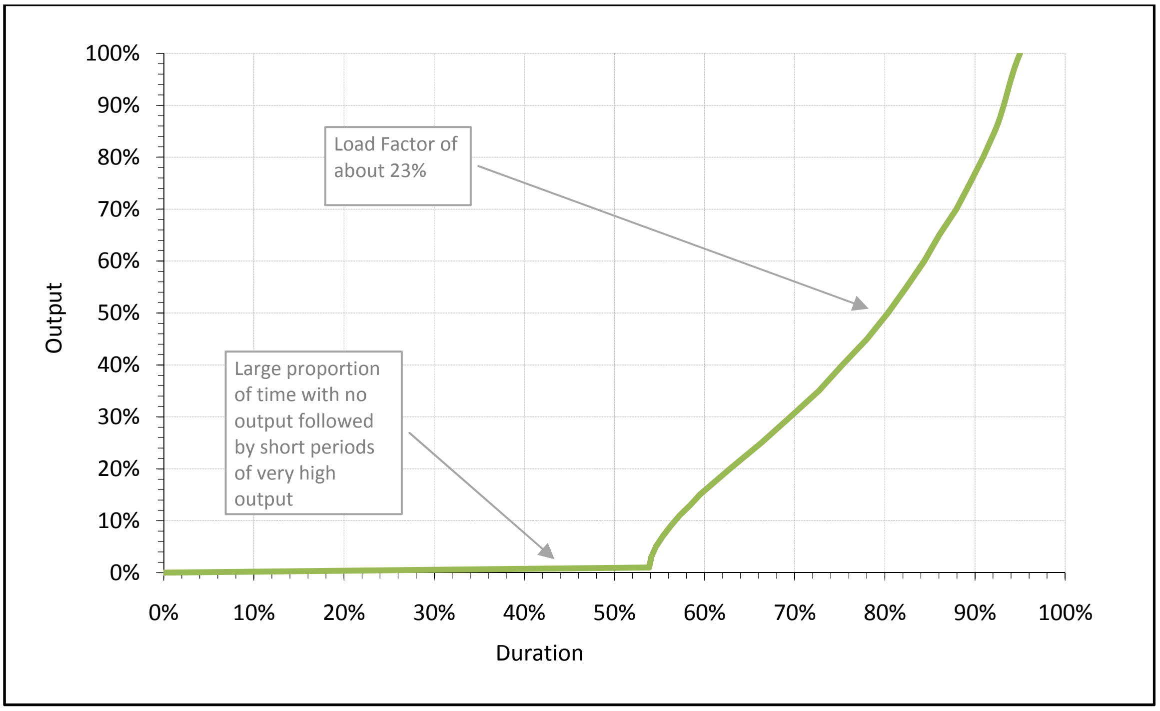
between the reservoir and the sea. In the case of the Severn this could create large short term increases and decreases in power output of between 6-8GW. Although the timing and magnitude of these peaks of power are predictable as they follow the tidal patterns, when combined with worst-case fluctuations of wind output under some of the 2020 renewable scenarios considered in this study, could result in half hourly variations about double the current maximum excursions (Section 6.2.6). Additional amounts of flexible plant than currently used in the system will be required with the consequential impact on ancillary services payments by the system operator.

Figure 4.11 Example of simulated Severn barrage output



The maximum resulting load factor is however relatively modest below around 23% (Figure 4.12) of similar order of onshore wind but only about half of the expected offshore wind load factor.

Figure 4.12 Severn barrage load duration curve



It can be concluded that in terms of tidal barrage technology, although tidal barrages in the Severn and Mersey have been proposed, it has been assumed that such schemes will not be built before 2020 given the scale of the investment required (potentially around £15 billion for around 8.6GW and hence similar specific cost-£/kW- compared to offshore wind) to deliver a single Severn barrage scheme, its relatively low load factor (offshore wind is double) and the impact on system reserve requirements and hence their compatibility with a system with high wind penetration. Greater scope might exist for the development of the smaller Mersey barrage – but, given the time frame assessed, we have also not assumed its construction within the time frame of our scenarios.

4.3.3 Total Renewable Generation Capacity

Table 4.5 shows the total renewable generation capacity assumed in each 2020 renewable scenario broken down by onshore and offshore wind, biomass and other renewables.

Table 4.5 Renewable Generation Capacity (GW)

		2020 Renewable Scenarios		
Type	2008	Lower	Middle	Higher
Onshore Wind	3.5	11.5	12.9	14.3
Offshore Wind	0.2	21.6	25.7	34.2
Biomass	0.2	2.2	2.9	3.3
Other renewables	2.2	2.3	2.3	2.3
Total renewables	**6.1**	**37.6**	**43.8**	**54.1**

It is clear from Table 4.5 that a considerable expansion of offshore wind is required to meet the renewable targets in each scenario. Even in the *Lower scenario* over 21 GW of offshore wind is required, rising to almost 26 GW in the *Middle scenario* and over 34 GW in the *Higher scenario*. Supply constraints are likely to represent a considerable challenge in the development of offshore wind, although we do assume that the indicated level of renewable capacity is achieved by 2020.

4.4 Conventional Plant

Although wind will be able to provide a significant proportion of the energy demand in 2020, even becoming the largest single energy system source in the *Higher Scenario*, conventional plant will continue to play an essential role in securing supplies through a diversified fuel mix and in managing wind intermittency.

4.4.1 Security of Supply

A key consideration in the scenarios is the need to ensure that security of supply is adequate in 2020. One indicator of an electricity system's security of supply is the plant margin – where plant margin is determined as the generation capacity in excess of peak demand. The plant margin protects the system against factors such as unplanned generating plant outages. A plant margin of 20% is commonly cited as a reference value for the GB grid, however this is based on the historic performance of conventional generating plant.

The variability of wind output, given the variability of wind as a fuel source, means that wind cannot replace existing plant, which has a higher overall availability, on a like for like basis and results in three key impacts:

- It leads to the significant increase in total installed capacity in all scenarios
- It leads to an increasing reserve requirement for the system
- It leads to a declining average plant load factor.

These factors, together with expected plant closures have been taken into account in determining the conventional plant requirements under each of the renewable scenarios in 2020.

4.4.2 Generation plant closures

In all three 2020 renewable scenarios it is assumed that all coal and oil-fired plant currently opted out of the Large Combustion Plant Directive will close, at the latest by 2015. Those CCGTs that are earmarked for closure in NGT's Seven Year Statement are also assumed decommissioned. Furthermore it has been assumed that only three existing nuclear stations will remain operational in 2020.

In addition further plant closures occur within each scenario, depending on the generation mix required to satisfy demand and ensure security of supply. A small volume of coal plant that has been retrofitted with flue gas desulphurisation (FGD) is closed by 2020, but given the remnant life of this plant and its potential role as back up capacity to support wind generation –discussed in 4.2.9- over 90 per cent is assumed to remain in service.

Along with the closures outlined in NGT's Seven Year Statement some further CCGT plant is assumed to close after a minimum 20 year life. However, a 20 year life is not a common assumption for CCGT technology – it has been assumed that some CCGT remains open after a 20 year life which reflects gradually reduced utilisation and consequential increase in useful life consistent with the renewable scenarios.

4.4.3 New generation plant

In all three 2020 renewable scenarios it is assumed that three 'New coal' generating stations are commissioned over the period to 2020. The technology does not initially assume carbon capture and storage but is characterised as 'New coal' due to the higher efficiency of the generating technology. We also assume that two new nuclear stations are commissioned in each scenario by 2020 and that the proposed BritNed interconnector, connecting the UK with the Netherlands, is completed before 2020. In addition we assume that the role of microgen increases in all scenarios.

In addition some additional new CCGT capacity is commissioned in each scenario. The volume of plant commissioning is not uniform across each scenario but is determined by the requirements of the model and the volume of other forms of generation. A key determinant of the volume of additional CCGT plant required in each scenario is a function of the volume of renewables assumed in each scenario – with more CCGT plant constructed in the *Lower scenario* than the *Higher scenario*. Any CCGT capacity commissioned in the scenarios has already been earmarked for development, with plant considered having a high probability of proceeding developed before plant considered having a lower probability of proceeding.

4.4.4 Total Conventional Plant in 2020

The resulting total conventional capacity in each scenario in 2020, after accounting for all closures and commissioning plant, is shown in Table 4.6. Overall conventional generating capacity declines in all scenarios. The greatest decline occurs in the *Higher scenario*, where conventional capacity falls by almost 17 GW, i.e. over 20 per cent. The smallest decline occurs in the *Lower scenario* with a fall of around 14 GW, around 17 per cent.

The largest decline over the period to 2020 in all scenarios is of coal-fired capacity – with over 7 GW of this decline attributed to plant that has currently opted out of the Large Combustion Plant Directive. The construction of some new 'New coal' plant (supercritical coal technology) , including developments earmarked for Kingsnorth and Tilbury, is at these 'opted out' power station sites.

Table 4.6 Conventional Generating Capacity (MW)

		2020 Renewable Scenarios		
Type	2007	Lower	Middle	Higher
New coal	0	3,700	3,700	3,700
Coal	29,363	18,270	18,165	16,882
Gas	29,436	29,270	27,800	27,330
Nuclear	10,602	6,022	6,022	6,022
Interconnectors[7]	1,988	3,308	3,308	3,308
Microgen		1,000	1,000	1,000
Other	9,556	5,762	5,762	5,762
Total Conventional	**80,946**	**67,332**	**65,757**	**64,004**

Total gas-fired capacity falls marginally, with installed capacity in the *Lower scenario* little changed from 2008 – although this masks the churn associated with commissioning and decommissioning CCGT plant. In both the *Middle* and *Higher scenarios* gas-fired capacity declines further, but even in the *Higher scenario* gas-fired capacity has declined by only 8 per cent below present levels.

Table 4.6 also shows a net reduction in nuclear capacity of around 4.5 GW by 2020. Only two AGRs and one PWR remain operational by 2020; however 2.5 GW of new nuclear capacity is constructed.

The decline in 'other' capacity includes the closure of over 3 GW of oil-fired plant and some additional open cycle gas turbine plant.

4.5 Total Generation

Table 4.7 and Figure 4.13 show the resulting generation requirement in each 2020 renewable scenario. Figure 4.14 shows the generation mix as percentage of installed capacity. It is clear that, in all scenarios, total generation capacity required in 2020 rises significantly, despite no demand growth. As renewable capacity increases over the period to 2020 conventional generation does not decline at a compensating rate, leading to the large increase in total generating capacity. The increase in total capacity required in 2020 is a direct result of the rise in the proportion of wind capacity, the nature of wind generation as an intermittent source of electricity supply and the need to maintain security of supply.

[7] Connections with mainland Europe included for the purpose of calculating the plant margin.

Table 4.7 Total Generation Capacity in the 2020 Renewable scenarios (MW)

Plant Type	2007	2020 Renewable scenarios Lower	Middle	Higher
New coal	0	3,700	3,700	3,700
Coal	29,363	18,270	18,165	16,882
Gas	29,436	29,270	27,800	27,330
Nuclear	10,602	6,022	6,022	6,022
Interconnector	1,988	3,308	3,308	3,308
Other	9,556	6,762	6,762	6,762
Total non-renewables	***80,945***	***67,332***	***65,757***	***64,004***
Onshore wind	3,515	11,474	12,924	14,274
Offshore wind	240	21,562	25,712	34,212
Biomass	194	2,168	2,898	3,298
Other renewables	2,167	2,274	2,274	2,274
Total renewables	***6,116***	***37,478***	***43,808***	***54,058***
Total capacity	**87,061**	**104,810**	**109,565**	**118,062**

Figure 4.13 Total Generating Capacity in 2020 (MW)

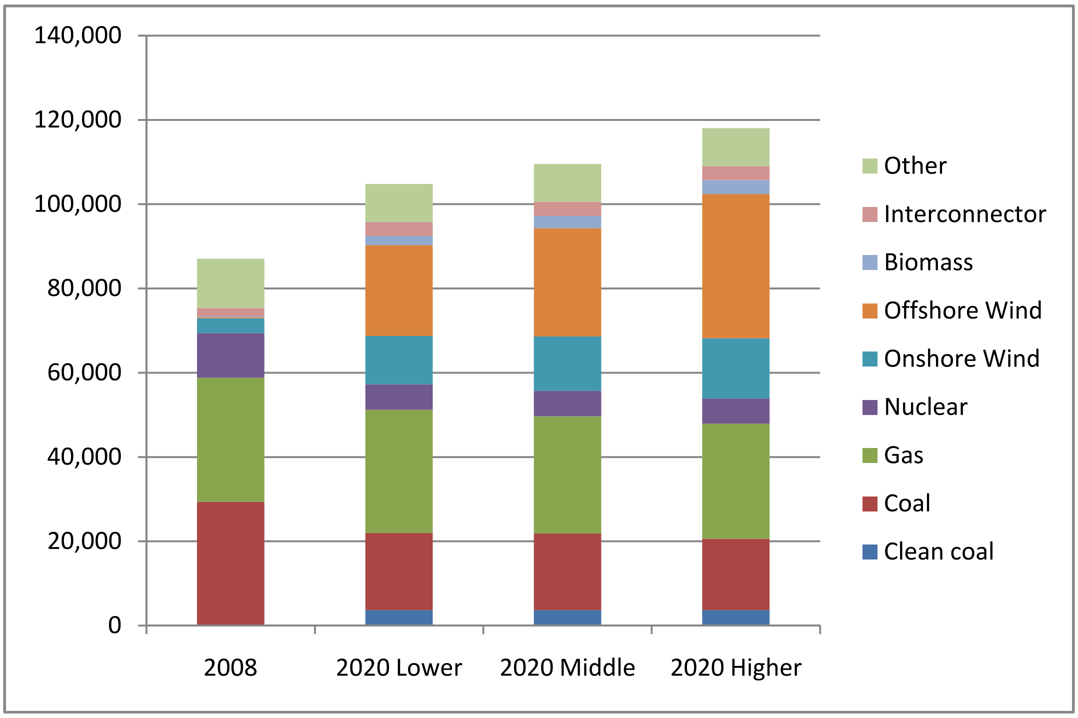
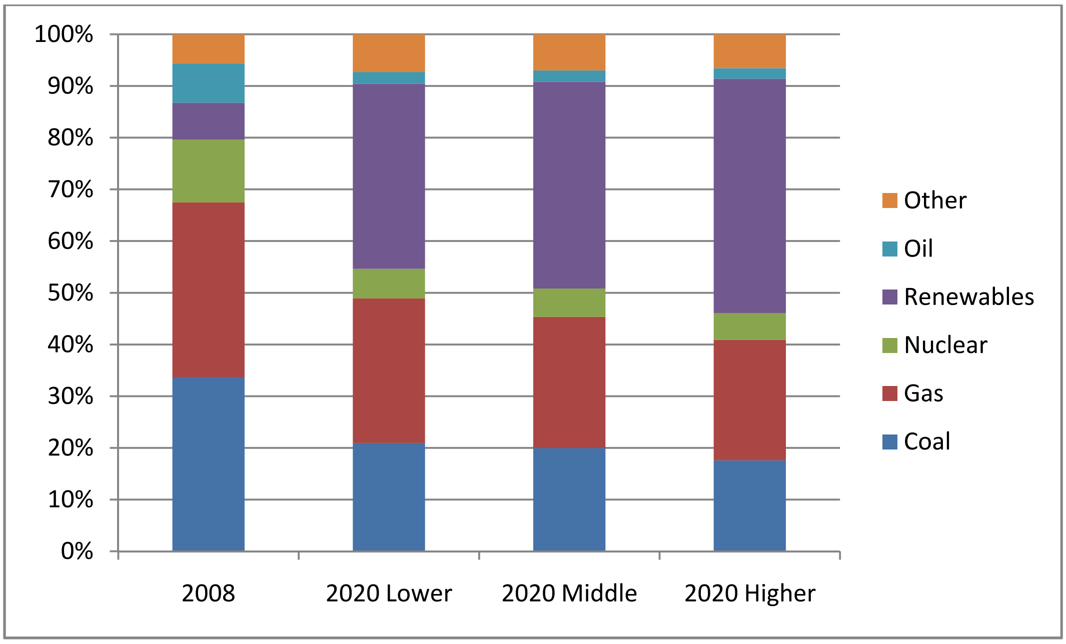


Figure 4.14 Generation Capacity Mix (%) by installed capacity.



5 Grid Connection

5.1 Overview and Summary of key findings

This section focuses on the analysis of the connections for the offshore wind farms required to achieve each of the renewable scenarios by 2020. A review is undertaken of alternative connection technologies and their costs in order to optimise the connection arrangements for each site considered in Section 4.2.2. The connection costs associated with onshore renewables are discussed in Section 7.6.2

5.2 Background for Grid Connections

The Main Interconnected Transmission System[8] (MITS) in Great Britain and the transmission networks in Northern Ireland are alternating current (ac), networks which operate at a nominal frequency of 50 Hz and at voltage of 400 kV and 275 kV in England and Wales[9], also at 132 kV in Scotland and at 275 kV and 110 kV in Northern Ireland.

The bulk of the electricity users (demand customers) take power from the networks at lower voltages, namely 33 kV, 11 kV and LV (415/230 V) via step-down transformers and the local distribution networks, although certain major demand customers may take supply at 132 kV or at one of the higher voltages.

The users who feed power into the electricity networks (generation customer) are usually connected at the higher voltages, i.e. 400 kV, 275 kV and 132 kV. Historically such customers operate large conventional power stations burning either coal or gas (sometimes dual fuelled with oil), or derive energy from nuclear reactors or else from hydro electric energy sources. In some cases users may combine electricity generation with the production of heat (CHP) for industrial process purposes or for district heating and will generally connect at 132 kV or below. With the growth in smaller capacity renewable generation sources, mainly wind turbine generators (WTGs), a number of customers are also delivering power at the lower voltages of 132 kV, 33 kV and 11 kV and there is also the possibility that in future large numbers of domestic customers may feed power from small domestic CHP generation (microgeneration) into the grid at LV.

---

[8] The terminology, Main Interconnected Transmission System is used within the Great Britain Security and Quality of Supply Standards (GB SQSS) and is a convenient term for describing the bulk of the 400 kV and 275 kV transmission networks in Great Britain. The use of the term MITS also tends to avoid potential confusion based on Licensee ownership issues, i.e. with the transmission networks in England and Wales being owned by National Grid Electricity Transmission (NGET), that in the South of Scotland by Scottish Power Transmission Limited (SPTL) and that in the North of Scotland by Scottish HydroElectric Limited (SHETL).

[9] In England and Wales, whilst 132 kV is widely used, it is operated by the ten regional Distribution System Operators (DSO's) although in many applications it is better described as a sub-transmission, rather than as a distribution voltage.

It is clear from the overall capacity of proposed additional renewable generation connecting to the UK network and also from the technology, predominately WTG and location, with significant capacity assumed offshore, that the means and cost of connecting such generation to the grid may be a significant factor influencing the overall mix of generation in the future and also the disposition of the same although locations are very much determined by the availability of the resource and also (town and country) planning issues, as well as connection costs.

5.3 Generation connection technology

The capacity of individual generation connections and their associated costs are largely determined by the rating (MW) of the connecting plant and the distance and characteristics of the connection route. In general and whenever practical, connections between generation and the nearest suitable grid connection point will be established using ac overhead lines. General practice in the UK is to make use of double circuit construction, steel lattice tower lines with such lines providing a degree of redundancy, i.e. each circuit on the line may be capable of transmitting the full capacity of the connecting power station. In GB, such an approach has been adopted for power stations up to about 1320 MW with larger power stations being connected by at least three circuits, more generally by two double circuit line (four circuits). In certain cases and when connecting only one large unit, or a number of smaller units, only a single circuit connection may be provided, particularly if it is deemed necessary, or appropriate to use an underground cable and in such cases generation capacity up to about 1,000 MW may be connected.

Due to their significantly higher capital costs than overhead lines, underground cables have only been employed within urban areas or when traversing particularly important landscape areas, e.g. National Parks (Snowdonia), or occasionally where a generation developer has elected to use such a connection in order to avoid delays and project risks and delays associated with public inquiries and wayleave hearings. With the envisaged connection of significant amounts of offshore renewable generation, and the absence of the necessary grid capacity adjacent to the shoreline it is possible that significant lengths of underground cable may be utilised for such connections if the route involves crossing sensitive and/or scenic coastal area. At 132 kV and 220 kV, relatively lower cost XLPE, three core cable technology can be utilised, and in such case the associated cost penalty (circa 4 times that of overhead lines) may be considered acceptable given overall project costs. At higher voltages, e.g. 275 kV and 400 kV the cost differential between underground cable and overhead lines increase significantly, both in terms of cost multiplier (about 8 times[10]) and in total capital cost, i.e. an additional cost about £10million/km, which in themselves act as a barrier to the use of the higher ac voltages for accessing offshore connections.

---

[10] At these voltage levels, three single core cables are required for each circuit and, as XLPE technology is considered relatively unproven, the use of traditional, higher cost paper/oil insulation technology is assumed.

In the case of connections to offshore renewable generation the use of submarine cables is the only credible method of connection for the marine segment. However, with respect to submarine transmission there is a choice and also some technical restrictions on the technology that can be adopted which also impact on capital and operational costs associated with offshore connections. These aspects are considered in somewhat greater detail in the sections below.

5.4 Generation connection planning

Generation connections are planned to somewhat different levels of security (redundancy) than the main MITS. In summary in GB, connections to onshore generation should be such that no more than about 1000 MW of "power infeed" should be lost in the event of any single circuit fault and no more than 1320 MW in the event of a double circuit overhead line fault or two concurrent (overlapping) single circuit faults. Additionally, resulting from the GB Electricity Market rules (BETTA), generation connections are generally planned by the transmission licensees such that generation output will not be constrained (limited) by operating secure against the risk of any single incident[11]. In Northern Ireland, due to the smaller size of the network and hence the greater impact of a major loss of power, somewhat greater redundancy is built into generation connections and the system is planned and operated so that when operating as part of the All Island network[12], no more than about 400 MW can be lost as a result of a single incident.

The generation connection requirements referenced above are reflective of the rules largely established by the CEGB, and the Scottish and Northern Ireland equivalents, prior to the restructuring of the UK ESI. In the case of GB, these are largely reflective of the historic (1970's) use of large (up to 660 MW) individual generation units and the identification of cost effective generation connection arrangements at that time. These rules have evolved only slightly during the post restructuring period, largely driven by market rules and treatment of generation constraint issues, although they are currently under review, initiated in part by the radically different characteristics of renewable (wind based) generation and the attendant impact on cost-benefit based connection arrangements.

Generation connection requirements for offshore generation connections have been subject to more recent[13] consideration and consultations. However, recommendations with respect to planning the

---

[11] Operation in this mode is often termed N – 1, or N' – 1 secure, where the N state represent an intact network operating state, i.e. all transmission plant in service, and the N' state represent the operating state with one (or more) circuits out of service for planned maintenance. The " – 1" signifies that the network is then operated secure against any single event. In contrast, the MITS is often required to be operated secure under N – 2, N' – 2 or N – D, i.e. secure against any two overlapping single events or the loss of a single, double circuit overhead line, the" – D" event.

[12] The interconnected electricity network of Northern Ireland and the Republic of Ireland.

[13] The GBSQSS sub group presented their recommendations to Offshore Transmission Experts Group (OTEG) on Friday 29th September 2006. Those recommendations formed a basis for the BERR/Ofgem Initial Consultation on a Security

security of the offshore transmission network align closely with those applicable onshore with respect to allowable loss of power infeed although in the case of ac offshore transmission, no redundancy is required providing the single incident loss does not exceed 1320 MW, whether under an N – 1, or N' – 1 condition. In contrast, for HVDC transmission, where normally, two 50 percent rated units would be employed, the N – 1 loss should not exceed 1000 MW and under N' – 1, should not exceed 1320 MW.

5.5 Generation connection charges

The connection between the MITS and individual power stations are termed Generation Connections. Within the charging principles applicable within the GB MITS, the charges which fall upon the Generators are limited to charging only for those assets which are for the sole use of the Generator, with the costs of assets that integrate the generation into the grid being classed as infrastructure and socialised across all users. However, within the context of the generation costs identified as part of this present work, such connection costs are quantified as generation connection costs. In the main these "infrastructure" costs will arise through the need to establish new grid substations or to extend the grid towards the shoreline, in the case of offshore generation connections.

5.6 Offshore connection technology

As indicated above, UK practice with respect to MITS and also generation connections has been based upon the use of alternating current (ac) technology and whenever practical overhead lines. The present use of direct current, in the form of High Voltage Direct Current (HVDC) is limited to submarine connections between the ac systems on adjacent land masses, i.e. the Moyle Interconnection between Northern Ireland and Scotland and the Cross Channel Interconnection between England and France. Contracts are also in place to establish a second interconnection between GB and Europe, namely the Brit-Ned Interconnection between England and The Nederlands.

Although the incremental (per km) cost of HVDC is less than that of comparable ac voltages (due to the inherently better utilisation of the voltage-current characteristics[14]) transmission mediums,

---

Standard for Offshore Transmission Networks dated 13 December 2006. In their response to the consultation, published in April 2007, the Government decided that the cost benefit analyses completed by the GB SQSS sub group was a sound basis for the development of the offshore standard and accepted the initial recommendations except for two, which were subsequently modified in line with the Government's findings. Although the results of analysis relating to the use of overhead lines (to continue the offshore connection overland to a receiving onshore substation) were provided to OTEG, it is not clear whether the findings have been fully reflected into the proposed planning standards.

[14] Direct Current transmission allows 100 percent usage of the voltage x current characteristics of a transmission line or underground cable whereas due to the sinusoidal form of an ac voltage wave, the equivalent of only $1/\sqrt{2}$, or 70 percent of the voltage capability can be used on ac systems, i.e. $Vrms = Vpeak/\sqrt{2}$. Additionally, dc system capacity is not directly affected by capacitive and inductive effects which act as limiting factors (or require expensive compensation) on ac systems.

whether overhead line or cable, the use of HVDC as a general electricity transmission tool for onshore networks has always been handicapped by the high costs of the ac/dc conversion equipment required at each end of an HVDC link, and the relatively short transmission distances associated with power transmission within relatively densely populated regions[15]. Cases where HVDC has been considered economic, other than for submarine interconnections, are for very long high power point to point transmission, for example in Africa and South America and for the establishment of interconnections between otherwise incompatible ac systems, i.e. 50/60 Hz in North and South America and "Back to Back" interconnections between East and Western European power grids.

In the case of submarine cable interconnections, the twin benefits of better utilisation of expensive submarine cable technology, coupled with allowing the interconnection of large independent synchronous networks without introducing, or transferring synchronous stability problems have been the main determining factors behind their adoption. However, in the case of connections with offshore windfarms, the latter factor is unlikely to be significant although the added flexibility of being able to immunise the offshore network from onshore disturbances and also permit operation over a wider frequency range may become an important factor, particularly if WTG technology develops to serve the offshore environment.

The generation scenarios outlined elsewhere in this report identify significant tranches of offshore renewable generation and also indicates the likely geographic disposition of the same.

The assumptions associated with the High Scenario are presented in Figure 4.4 and it can be seen from this figure that a wide spread in generation capacities and also offshore transmission distances is indicated. When considering the appropriate generation connection technology it is important that these issues are also considered.

The offshore generation capacities indicated above expressed in terms of that generation capacity already in hand, either installed, under construction or consented under Round 1 and Round 2, together with the additional capacity assumed by 2020 and associated transmission distances are presented in Table 5.1 below.

[15] During the 1960's an HVDC underground cable based system was commissioned by the CEGB, between Kingsnorth power station on the Thames Estuary and central London. This introduced some practical benefits with respect to high power transmission through a high population density area and also provided a test bed for an evolving technology at that time. Whilst it operated for many years, the system has now been dismantled and was not been replaced by a modern equivalent.

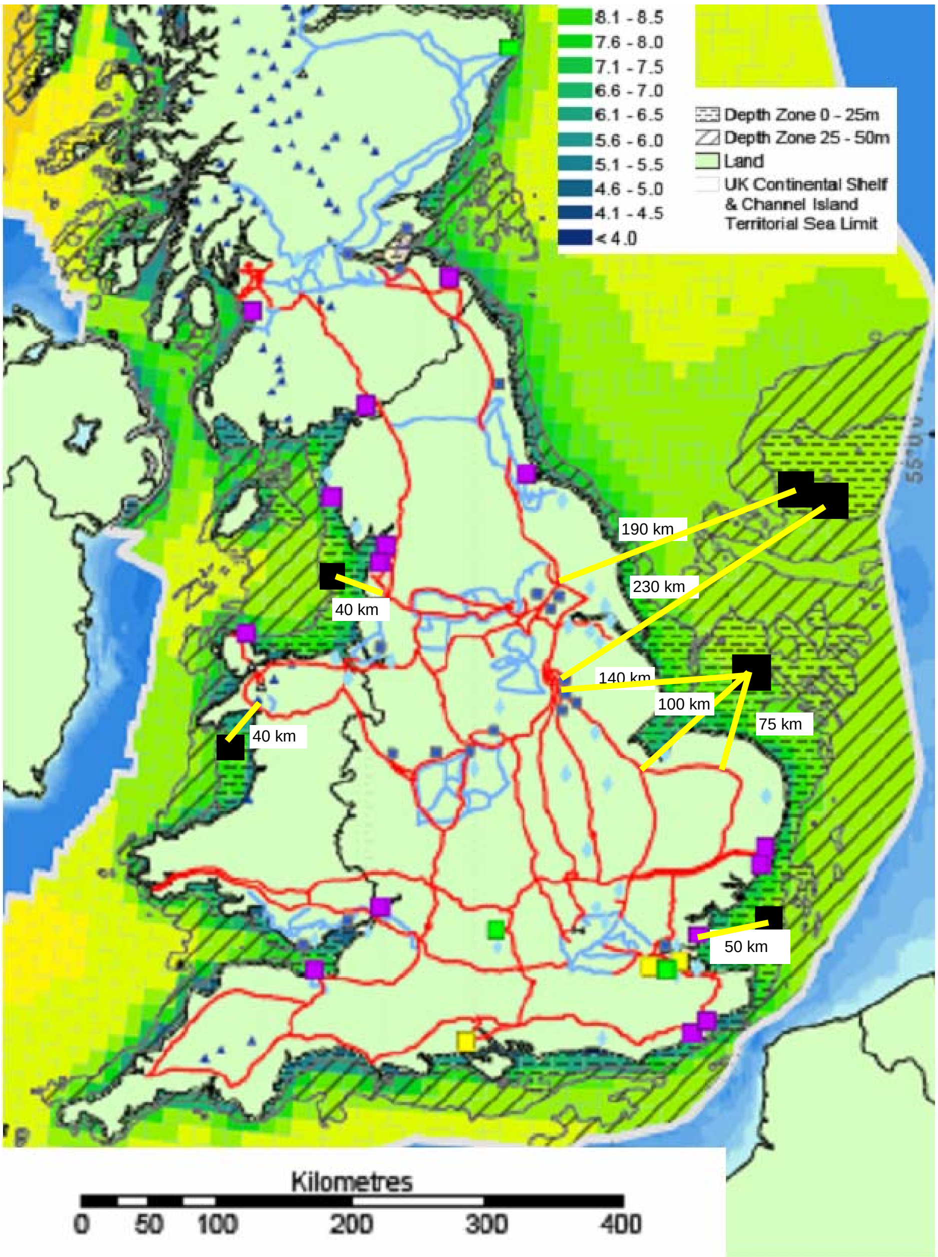
Table 5.1 – Offshore wind generation capacity – High Scenario

Region	*Round 1 + 2 - Under construction/ consented (MW)*	*Installed Capacity (MW) by 2020*		*Distance (km) to:*	
		Higher Scenario	**Additional to Rounds 1 + 2**	**shoreline**	**suitable grid connection**
Wash	4,068	8,000	3,932	40 - 90	75 - 140
North West	2,588	5,000	2,412	30	40
Thames	1,954	2,800	846	50	50
Severn	108	108	0	-	-
North East	94	94	0	-	-
Scotland	10	10	0	-	-
Wales	0	2,500	2,500	40	40
Dogger	0	15,000	15,000	120 – 180	190 - 230
Total	**8,822**	**33,512**	**24,690**		

The approximate location of offshore generation block capable of producing the power levels indicated above and the associated transmission direct route to the GB shoreline and on to an appropriate grid connection point are taken from Figure 5.1 overleaf. This figure shows the GB mainland together with the 400 kV (red) and 275 kV (blue) transmission grid, plus in overlay form the surrounding seabed contours (patterned) and associated mean wind speeds (coloured). Based upon this information it is possible to make outline estimates of the post Round 2, offshore wind farm locations and also the approximate, straight line transmission distances to the main parts of the onshore grid (MITS).

Based upon the generation capacities and transmission distances presented in Table 5.1 above it is possible to investigate the likely capacity and costs of alternative submarine transmission capacity that would be appropriate to its connection. However, it is important to note that given some of the indicated transmission distances onshore, in some cases up to between 50 km to 70 km, onshore transmission costs may also be a significant factor in any comparisons of alternatives.

Figure 5.1 – Offshore wind farm – GB grid relationship, indicative distances



5.7 Offshore generation connection costs.

The costs and range of technologies employed may be addressed under the following main headings:

1) Inter-array cabling, or WTG collection circuits
2) Offshore transformer platform (or offshore sub-station)

3) Export cable to shore
4) Onshore transmission link (if necessary)
5) Grid connection, and associated grid infrastructure.

5.8 Inter-array cabling

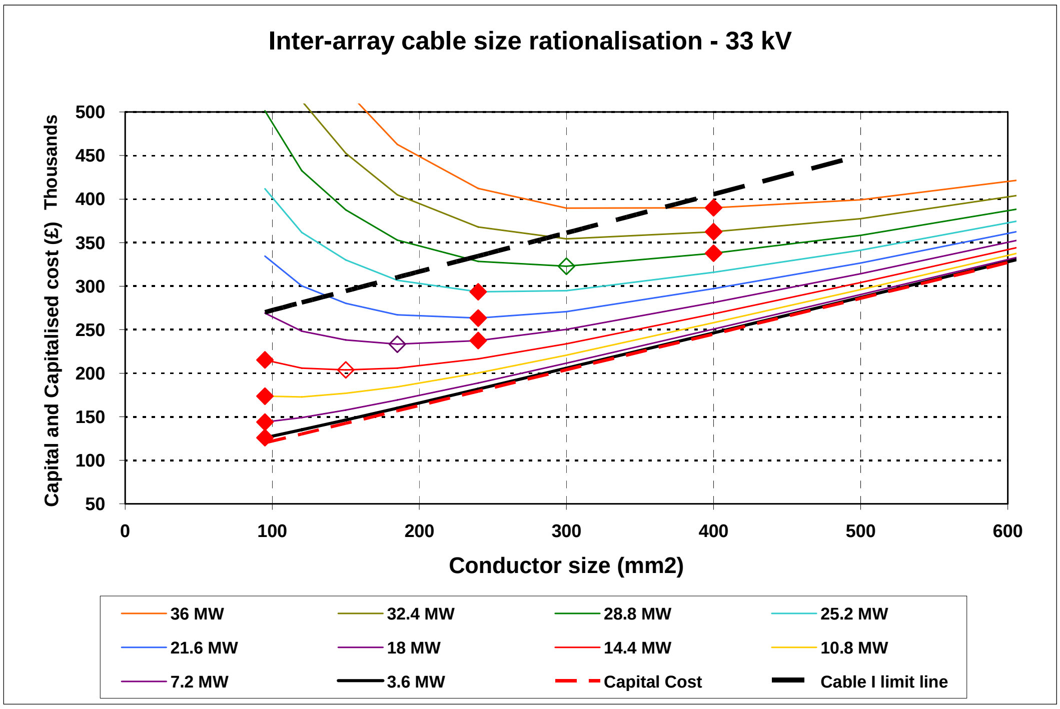
In the case of almost all of the offshore wind farms either in operation, under construction or planned, the practice has been to use ac technology to connect individual WTGs, generally via a WTG transformer, to a “daisy chain” cable which progressively connected between 4 and 10 WTGs. With the larger wind farms this submarine cable will typically operate at voltages up to 33 kV and is analogous to a typical collection circuit employed within onshore wind farms and also the arrangement employed in local onshore distribution circuits.

In order to minimise capital costs, the cable will generally taper (reduce in cross sectional area) as it progresses towards the outermost WTG although, for standardisation purposes, to minimise construction costs and complexity and also “spares” holdings only about three standard cable sizes will be adopted. Even if this chain is looped with an adjacent chain, in order to provide a degree of redundancy against a forced or planned outage of one of the cable section, the same tapering approach is indicated.

The above approach is supported by economic analysis taking into account the capitalised value of associated cable losses. An example would be a string of up to ten, 3.6 MW WTG where the four outermost WTGs would be connected via a 95 mm^2 copper XLPE insulated 33 kV cable, the next three via 240 mm^2 cable and the final three via 400 mm^2 cable. The result of an assessment of a typical wind farm inter-array cable string is presented in Figure 5.2 overleaf. Each of the lines presents the capitalised value of a particular string, respectively loaded with one, two, three, etc WTGs. In this example, losses have been valued at £100/MWh and, consistent with developer requirements these are capitalised over 15 years at 10 percent. In this case, which is representative of a well positioned offshore wind farm a Loss Load Factor of 28 percent has been used.

It is worth noting that the inter-array cable costs include a factor reflecting the costs of cable entry and exit from each of the WTGs on each string, via “J” tubes and also the costs of termination in each WTG. Given the relatively close spacing, between about 800 m and 1200 m for a typical WTG array, these costs are a significant (fixed) addition to cable supply and laying costs.

Figure 5.2 – Inter-array cabling – Life-time costs/km



It can be seen from Figure 5.2 above that life-time costs not unduly sensitive to cable size, hence it is possible to standardise on only a limited number of cable sizes whilst still maintaining a near optimal solution.

Based upon the above analysis, which is reflective of currently tendered prices for cable supply and installation, the capital cost of a typical inter-array cable arrangement corresponds to about £ 50/kW[16]. In addition, the capitalised losses for such an arrangement correspond to about £ 790,000 which reflects an annual energy loss of just over 1 GWh per string, equivalent to 0.8 percent of energy production (39 percent load factor). This in itself is reflective of a loss of about 1.2 percent of the power entering the string at times of rated power output from each of the connected WTGs. It should be noted that if the wind farm load factor, and associated loss load factor varies from the above, then the percentage loss values will also vary, albeit not to any significant extent. Notwithstanding this latter point it is considered that calculated inter-array costs and losses presented above will not be unduly sensitive to the use of larger or smaller WTGs, which will tend to modify the number of WTGs per string and also the section lengths but will not significantly change the underlying costs/kW or percentage loss values.

---

[16] Based on 4 turbines at £125,000/km + 3 turbines at £ 175,000 + 3 turbines at £ 250,000 and an average spacing of 1000 m, hence total cost of £ 1,775,000 for a 10 x 3.6 MW string.

5.9 Offshore transformer platform

5.9.1 General

The costs associated with an offshore transformer platform, or offshore substation basically reflect the costs of the associated electrical equipment and the costs of the structure required to support and protect this same equipment in an offshore environment.

The greater number of equipment items will typically comprise the 36 kV circuit breakers, required to control each of the outgoing WTG collector circuits. Whilst each circuit breaker, typically rated at about 630 A can support about 34 MW, if it is accepted that there will invariably be a degree of sub-optimal development of the wind farm licensed area due to the presence of wrecks and other obstacles (crossing cables, shipping routes, exclusion areas, etc) and also localised ground strength issues, it is considered that typically about four 33 kV collector circuits will be required for each 100 MW of WTG capacity. Hence, for a 500 MW wind farm a total of about 20 incoming feeder circuits will be required together with associated bus-section and transformer circuits.

Each group of incoming 33 kV feeders there will be associated with a step-up transformer, required to increase the operating voltage to a level appropriate for onward transmission. Guidelines presented in the OTEG work referenced earlier (Section 5.4) indicate towards the use of two 50 percent transformers for each offshore wind farm. In the case of a 200 MW development, which will broadly map with the use of a single 132 kV export cable, see Section 5.10 below, this indicates the provision of 2 x 100 MVA transformers. In the case of a larger (300 MW) windfarm connecting using 220 kV, then the use of 2 x 150 MVA transformers is indicated.

The typical mass of such transformer corresponds to about 1 tonne per MVA. Whilst somewhat lesser weight transformers can be obtained, these will tend to be associated with higher losses. Given that the function of these transformers is to transmit high value renewable energy, it is likely that incorporation of an appropriate valuation of losses into the transformer design process will result in somewhat larger, more efficient (lower loss) designs will result, hence the assumption of 1 Tonne per MVA is considered appropriate. Each main transformer will most likely be associated with a smaller (1 - 2 MVA) auxiliary transformer to provide local, LV power supplies and may also double up as a means of earthing the neutral of the offshore 33 kV network.

Based upon current typical electrical equipment costs, and assuming a nominal wind farm capacity of about 200 MW and export at 132 kV, the capital costs for the above equipment will total about £ 9 million pounds, i.e. £ 45/kW. If the export voltage level is increased to 220 kV and capacity to 300 MW, offshore substation costs increase to about £ 15 million, i.e. £ 50/kW.

5.9.2 Export using ac cables

Where ac export cables are used, in order to maximise the use of the cable it is likely that some shunt reactive compensation will be provided on the offshore substation. Such reactors would normally be connected at 33 kV, or via a lower voltage (11 kV) transformer tertiary winding. Typically, for a single 132 kV export cable of say 50 km length, a total of about 25 MVAr of inductive (shunt reactor) compensation should be provided offshores, in the case of 220 kV this requirement would increase to about 60 MVAr. In addition, some means of isolating the export cable and also each of the connecting transformers should be provided. With the limited connectivity implicit in a single cable circuit connecting with two 50 percent rated transformers, only limited switching capability is required, essentially that required to allow isolation of the export cable and/or one of the transformers. These additional costs will equate to about £ 5/kW for 132 kV and £ 8/kW for 220 kV.

Taken overall, the offshore supporting structure requirements are minimal and are dominated by the need to accommodate and support the weight of the step-up transformers. Based upon a 200 MW wind farm, the total equipment weight will approximate to about 225 tonne. In the case of a 500 MW wind farm this weight would increase to about 550 tonne. These weights may be compared with the weight of a single offshore wind turbine, typically about 125 tonne/MW[17], i.e. about 450 tonne for a typical modern 3.6 MW unit. Foundation costs for such WTGs, when installed in circa 25 m of water correspond to about £ 1 million per turbine, hence the OTEG stated (BEAMA) estimate of £ 5 million per transformer platform appears quite conservative and presumably also includes provisions for accommodation and helicopter landing facilities and would seem to be applicable to a 500 MW wind farm. The implicit offshore structure costs therefore equate to about £ 10/kW, whether at 132 kV or 220 kV.

Based upon current capital costs for the ac equipment referenced above, including an allowance for a pro rata share in the costs of the supporting structure (£ 5 million) equate to about £ 60/kW for the 132 kV connection arrangement and £ 68/kW if 220 kV is used. These costs are consistent with the overall values implicit in the OTEG information referenced above and also with recent tendered prices for directly equivalent equipment.

Losses associated with an offshore ac transmission based transformer platform are predominately associated with the step-up transformer. Given the high valuation of losses that should be reflected within the transformer design, it is expected that these losses will be towards the lower end of the practical range for typical 132(220)/33 kV transformers with ratings of between 100 MVA and 250 MVA. On rating, these are typically about 0.05 percent for the no-load losses and 0.2 percent for load losses, indicating a peak power loss of about 0.25 percent. However, when computed taking into account the envisaged utilisation of the transformers when carrying the wind farm

[17] This weight, which includes the rotor, nacelle and tower, is based on the weight of a Vestas 2.0 MW offshore WTG and also the Siemens 3.6 MW WTG.

output, typical loss load factor of about 28 percent, these losses equate to an annual loss of energy equivalent to 0.27 percent[18] of generated energy (based on a 40% load factor).

5.9.3 Export using HVDC

With respect to the offshore substation, it is expected that the inter-array cable arrangements, interface 33 kV switchgear and step-up transformer arrangements will be very similar, with the incoming power being collected and transformed to a higher voltage better suited for conversion from ac to dc prior to transmission onshore. Hence the costs and characteristics identified in Sections 5.8 and 5.9.1 will still be applicable. However, with HVDC transmission, the need to convert electrical energy from ac to dc requires the provision of a significant amount of additional equipment, namely convertor transformers, power electronic conversion equipment and associated ac and dc harmonic filters.

Whilst HVDC can be used at lower power levels, the specific costs[19] of HVDC transmission reduce considerably with increasing power levels and operating voltage. As a result, it is expected that longer distance HVDC submarine transmission will make use of the higher proven range of equipment and associated submarine cables. At the present time these equate to operation at up to 450 kV dc, i.e. +/- 450 kV and with (cable) current levels of up to 1333 A. At these levels the power transmitted per bi-pole (+/- go and return cables) will equate to 1200 MW. At such power levels it is expected that offshore wind farms will be aggregated together, using (say) 132 kV submarine cables to deliver this level of power to an offshore converter station.

At the present time there are two main HVDC/ac conversion methods, the first and more mature technology is the Current Source Converter (CSC). This essentially uses the same principles as were employed in the CEGB Kingsnorth project[20] and contemporary projects and make use of the triggering of high voltage thyristors to convert an ac power source into dc and also to control the resultant ac and dc system voltages and/or power flow. However, to operate successfully, particularly with the commutation of current between each ac phase in turn, this technology requires a relatively strong ac system[21]. Whilst this will not be an issue within the likely terminal points on the GB MITS, even if a significant proportion of conventional plant is displaced at times

---

[18] 0.27 percent = (0.05% + 0.2% x 0.28/0.4)

[19] Specific cost in this context refers to £/kW.km or essentially the cost of transmitting several thousands of kW over several 10's or 100's of km divided by the kW.km product.

[20] The Kingsnorth and other contemporary HVDC links made use of Mercury Arc Converters, however modern thyristors are analogous to these in many respects.

[21] Typically the "fault level" of the connecting ac system should be >= 3 times the HVDC power level.

of high wind, this may not be the case at the offshore substation due to the nature of evolving WTG[22] technology.

The main alternative to CSC technology is the Voltage Sourced Converter (VSC) technology. This makes use of Gate Turn Off (GTO) thyristors or Insulated Base Bipolar Transistors (IGBT) devices which essentially operate as a high frequency controlled switch which allow the dc voltages to be chopped, at high frequency into varying size block such that the VSC can essentially determine its own ac voltage waveform. Accordingly it is not necessary for such a converter to be associated with a strong ac voltage source to ensure satisfactory current commutation. Such converters are ideal for use when feeding HVDC power into weak parts of an ac power system or, as may be the case when being required to convert ac power from a weak ac offshore power source. However, VSC utilise more expensive and somewhat more sensitive devices than CSC's, hence at the present time they are more limited in power conversion capability and are also somewhat more expensive. At the present time the capability of a VSC is limited to about +/- 150 kV and 350 MW however, this field of work is developing rapidly and it is expected that +/- 300 kV and 1000 MW will be available commercially within the next few years.

Alternatives to the use of higher cost and at present, limited capacity VSC technology would be to make use of related STATCOM[23] technology and/or refinements in the WTG converter interfaces to allow the use of CSC technology offshore[24].

In recognition of the issues associated with the offshore conversion equipment we consider it appropriate to allow for a higher cost for the offshore converters than for those onshore, in essence for the purposes of costing the HVDC submarine a hybrid converter arrangement is assumed. Whilst this would be novel at present, we consider that this provides an appropriate basis for reflecting likely near term costs of HVDC conversion costs within the specialised offshore wind farm environment.

---

[22] The bulk of the early WTG made use of induction generators which relied upon the external, ac system to provide excitation power. With the advent of Double Fed Induction Generators (DFIGs) it was possible to derive the excitation power internally and hence DFIG technology may, if so developed, be able to provide the necessary ac system strength. However increasingly, and largely driven by the need to minimise fatigue issues associated with WTG mechanical forces and inherent cyclic torque changes, full converter bridges are now being employed on individual WTGs. Whilst such conversion equipment may be developed to provide the necessary (equivalent) ac system strength, this is not a facility that is presently available.

[23] STATCOM are voltage/reactive power control shunt devices which provide a means of voltage waveform control akin to that of a VSC, but without requiring to carry the full output power of a VSC link.

[24] It should be noted that many of the commutation issues associated with the use of CSC technology are associated with the ability of the HVDC link to ride through external network faults and switching disturbances and, within the highly protected and condensed offshore electrical environment many of these issues will not apply.

5.9.3.1 HVDC commercial issues

Due to the significant interaction between the various components involved in a HVDC converter, it is usual to source all of the conversion equipment and associated controls and protection, filters and dc switching equipment from a single supplier. Additionally, because of the need for coordination between the equipment at the sending and receiving end of such links it is also usual to again source both converters from a single source supplier.

At the present time there are only a limited number of suppliers, essentially three namely ABB, AREVA and Siemens. Historically, the market for HVDC equipment has been very competitive and is likely to remain so, providing that there are sufficient projects available to support the high fixed costs of this business. Additionally, as the capability of power electronics is continually increasing, and specific costs £/kW of the power electronic devices continues to fall[25], significant development effort is expended by the three main players which further adds to the competitive nature of the business.

Due to the highly competitive nature of the HVDC transmission business, it is difficult to obtain firm budgetary prices for speculative projects. However, such information has been obtained in the past for specific projects and for relatively firm prospects at the specification stage. It is these costs that have used, inflated to present day costs as a basis for the cost estimates presented below.

Based upon the use of augmented CSC technology[26], and making maximum use of available technology, a 1200 MW, +/- 450 kV HVDC converter will cost about £ 132 million, i.e. £110/kW. This cost includes allowances for any necessary filters and shunt capacitors and for controlling ac and dc switchgear.

Based on the estimated weight of a 1200 MW installation of about 1400 tonne[27] together with the increased volume, necessary to provide electrical clearances for high voltage valve structures and harmonic filtering equipment, is estimated to cost about £ 20 million, i.e. equivalent to a further £ 17/kW given a total cost of about £ 127/kW for the offshore ac to dc conversion equipment.

---

[25] It should be noted that the constituent parts of an HVDC converter, namely thyristors and Gate Turn Off (GTO) devices are also produced competitively by parties other than the three HVDC suppliers mentioned. This equipment is also utilised in many industrial power converter, motor drives and other similar equipment and hence the core equipment suppliers also operate in an expanding and competitive market place.

[26] These costs are reflective of an onshore CSC installation enhanced by 20 percent to bring this into line with indicative VSC technology costs and/or as a proxy for the costs of enhancing the capability of CSC technology to ensure satisfactory operation in the offshore electrical environment.

[27] The major elements contributing to the total weight will be the converter transformers, again typically about 1 tonne/MVA

In addition to the ac/dc conversion costs outlined above, it should be noted that the ac equipment costs identified in Section 5.9.1, i.e. about £ 45/kW for platform 132/33 kV equipment is also applicable.

5.9.3.2 HVDC conversion losses

In contrast to the ac platform losses, largely associated with the 132(or 220)/33 kV transformer losses, ac to dc conversion equipment introduces significant additional offshore platform losses. Based upon published and measured information, the no load losses of an HVDC, CSC converter are about 0.1 percent, with full load losses increasing these by about 0.8 percent. Allowing for a Loss Load Factor of 28 percent, these losses equate to about 0.33 percent, expressed in terms of full load power. However, when expressed in terms of typical annual energy production (40 percent load factor), these losses equate to about 0.8 percent.

In the case of VSC technology, due to the continual high frequency switching action that takes place even at reduced loading levels conversion losses are indicated to be about 0.8 percent of rating, irrespective of loading. When expressed in terms of typical offshore wind farm energy production this will correspond to about 2 percent. When capitalised over the life of the plant, such losses become significant and act as a further driver to develop/adapt more efficient (CSC/STATCOM) technology for the offshore conversion role.

In the case of both the CSC and VSC, it should also be noted that the losses identified under Section 5.9.1, i.e. for the 132(220)/33 kV transformers, i.e. 0.27 percent of energy production will be additional to the above.

5.10 Export cable to shore.

5.10.1 Cable technology.

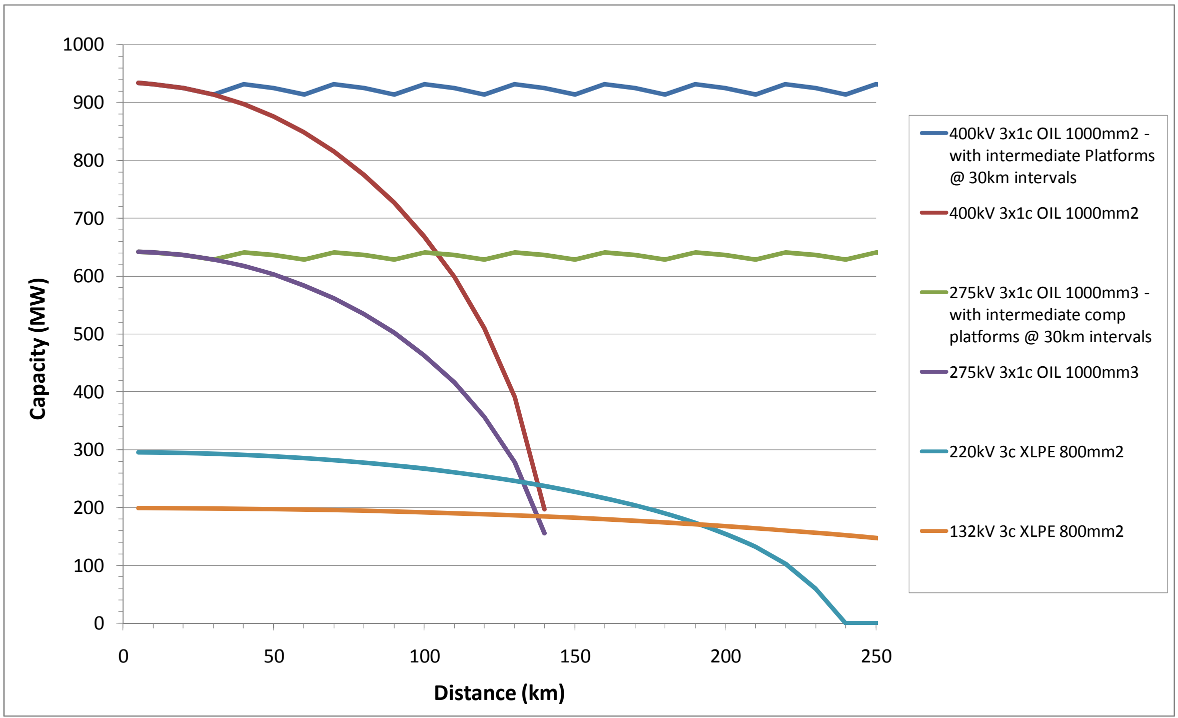
The choice between the use of a high voltage ac cable and an HVDC cable will be determined by a combination of cost and technical issues. Technical issues that are particularly relevant are the construction and type of cable employed. In the case of ac cables, due to consideration of cost and also reduced capacitance effects, a three core XLPE insulated cable will be preferred. Such cables are available with proven submarine performance at 132 kV. The use of the higher voltage of 220 kV has been advocated in a number of reports, however our understanding is that there is no service experience with an XLPE submarine cable of this voltage, or higher. Additionally, when examined from overall cost/benefit basis for the generic applications envisaged within this report, the use of 220 kV indicates little, if any advantage over 132 kV[28]. Where proven XLPE cable designs are available they are preferred to the more traditional impregnated paper insulation as they

[28] Overall specific cost comparisons of 132 kV and 220 kV ac technology and alternative HVDC technology are presented in Section 5.10.2 of this report.

allow higher operating temperatures and hence ratings and, due to possessing lower capacitance are lees affected by derating due to excessive reactive (charging) current issues.

In the case of ac voltages in excess of 220 kV, in GB essentially 275 kV and 400 kV, only traditional oil pressure cables are considered to have a proven capability. However, for the ratings appropriate to these voltages, only single core cables are available, with an implicit higher supply and also installation cost. Additionally however, oil pressure changes due to thermal cycling require that oil pressure management facilities are available at approximately 30 km intervals, which in the case of submarine cables implies the need for one or more pressure management platforms on cable routes greater than this distance. Additionally, the significantly higher charging currents associated with these cables will also require shunt reactive compensation on route, if a significant reduction in useful capacity is to be avoided. Comparison of available ac submarine cable capacity is presented in Figure 5.3 below.

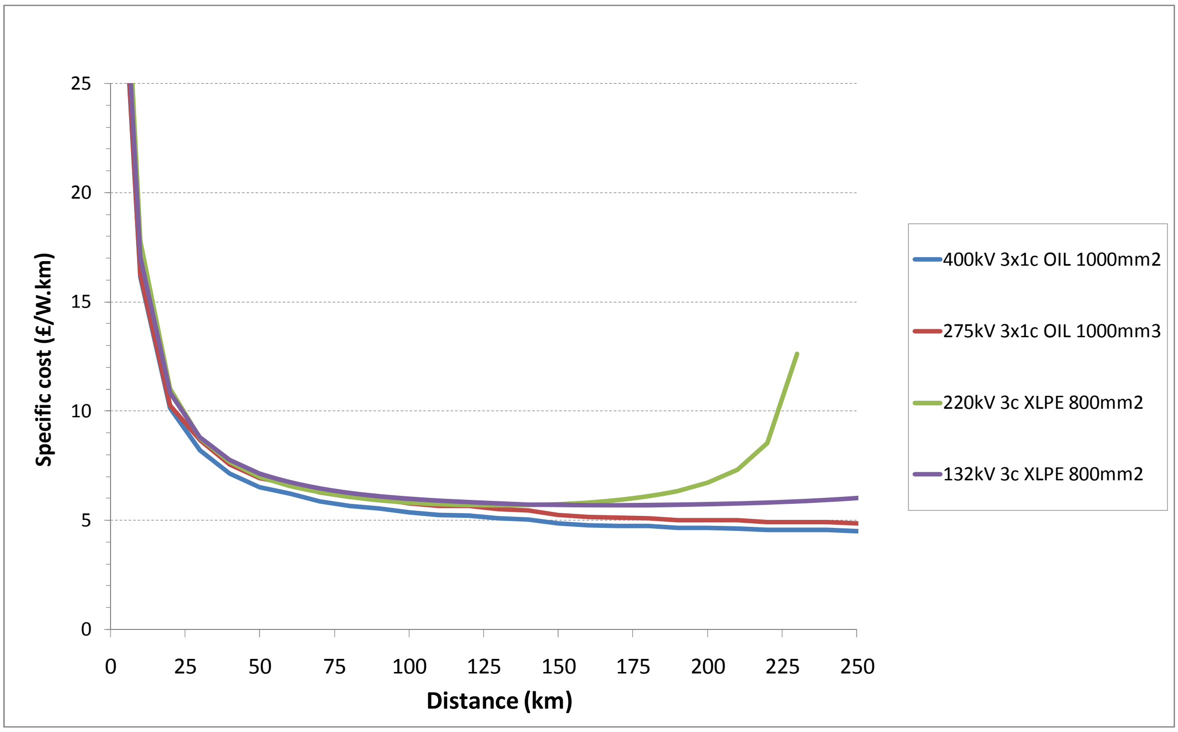
Figure 5.3 –ac submarine cable technology - capacity comparison



It can be seen from Figure 5.3 that in the absence of intermediate reactive compensation (doubling as oil pressure management) platforms, the useful capacity of 400 kV and 275 kV cables reduce significantly with transmission distance. In contrast 220 kV, XLPE and particularly 132 kV XLPE cables retain significant useful capacity up to about 150 km and 250 km respectively.

It should also be noted that if the significantly higher supply and installation costs of the 275 kV and 400 kV submarine cable circuits are taken into account, despite the higher nominal transmission capacity, the specific costs (£/kW/km) of these higher voltages are very similar to that of the two lower voltages, refer to Figure 5.4.

Figure 5.4 – ac submarine cable – specific cost comparison (£/kW.km)



It should be noted that the rapid increase in specific cost associated with the 220 kV cable is due to the useful capacity of the cable falling to near zero at about 225 km distance.

Hence, in summary the use of higher ac voltage cables plus intermediate compensation platforms does not deliver any economy of scale in comparison with lower voltage cables utilising proven XLPE technology. Additionally, as the higher voltage cables utilise three single core construction cables to deliver the indicated capacity, in comparison with the use of say three 132 kV cables (600 MW) or three 220 kV cables (900 MW), the lower voltage alternatives will display much greater redundancy, as any internal, or third party damage fault to one cable will only remove one third of the transmission capacity whereas with the higher voltage cable circuits, all of the circuit capacity would be lost. Accordingly, when considering ac submarine transmission, further consideration within this report is restricted to 132 kV and 220 kV although, due to the similar performance of these voltages, attention is focussed on the use of 132 kV, given that it is better suited for interfacing into the existing GB infrastructure and will be making use of proven submarine cable technology.

In comparison with ac cables, HVDC cables do not suffer from any issues relating to loss of capacity over longer distances, other than a proportional increase in their relatively small I^2R losses. In the case of potentially longer distance HVDC transmission, i.e. in excess of 50 km, the only practical proven technology suitable for operation at the highest voltages (+/- 450 kV) is the Mass Impregnated Non Draining (MIND) paper insulated cable. This type of cable makes us of well established manufacturing techniques and is available from all of the major submarine cable manufactures. It has been used in use since 1986 and to date has amassed over 18,000 km.years of use. Due to the materials used, it is relatively lightly stressed both electrically and thermally and therefore displays relatively low losses in comparison with ac equivalents and is ideally suited for transporting high value, renewable energy over long distances.

Considerable investigation has taken place over the last decade into the use of extruded (XLPE type) insulation for HVDC cables. This has been in part a parallel development alongside the introduction of VSC converters with ABB being the main driver and with the use of lower cost extruded insulation at HVDC being seen as something of a counter to the higher costs of the VSC technology. The development of the cable has tended to match that of the VSC converters with present operating voltage levels of 150 kV being enhanced up to 300 kV. Together with increased VSC current and voltage capacity these development are expected to result in VSC/extruded HVDC cable systems capable of transmitting up to 1000 MW in the near future.

5.10.2 Cable capital costs and losses

The capital costs associated with submarine cables may be broken into three main components, namely the costs of cable supply, the costs of mobilisation of a vessel to transport the cable to the proposed route followed by the laying and burial of the cable. Additional costs will also be incurred if cable routes cross over existing infrastructure, for example gas pipelines and other power or telecommunication cables. Additionally, where submarine cables are required to be laid and buried in relatively shallow waters (< 10 m), particularly when approaching land fall, there will be a need to utilise smaller and more time consuming vessels (barges) during this stage of insulation.

The capital costs of candidate cable types, have been based on the following cables:

- 132 kV, three core, XLPE insulated, 800 mm^2 copper (Cu) conductors.
- 220 kV, three core, XLPE insulated, 800 mm^2 Cu conductors.
- 450 kV, single core, MIND insulated, 1500 mm^2 Cu conductors.

In the case of the ac cables, which will carry less power and will be of somewhat shorter length, the use of Single Wire Armour (SWA) is assumed. However for the HVDC cable, Double Wire Armour (DWA) is assumed on the basis that the likely circuit lengths and high power levels warrant this additional protection. Cable laying costs also take account of the additional requirements and costs of the installation vessel necessary to undertake this work. Estimated capital costs for the cable detailed above are presented in Table 5.2 below.

Table 5.2 – Submarine cable costs

Cable Description	*Supply cost (£/m)*	*Lay and bury (£/m)*	*Mobilisation and extras (£/route)*
132 kV, XLPE, 800 mm^2 Cu, three core	400	120	1,000,000
220 kV, XLPE, 800 mm^2 Cu, three core	480	130	1,000,000
450 kV, MIND, 1500 mm^2 Cu, single core	300	100	1,000,000

These costs are based upon recently tendered costs for certain works, which have been used to index earlier detailed information. Additionally, cognisance has also been taken of information contained in OTEG submissions referenced earlier in this report.

The losses associated with the ac and dc alternatives differ considerably. In the case of ac submarine cables losses are incurred as a resultant of the constantly changing voltage stresses on the insulation (dielectric losses) as well as series I^2R losses. Additionally, due to the continuous flow of cable charging current, I^2R losses exist at times of low power transfers. A further loss which is also incurred in ac cables is due to the circulation of currents in the sheath and armouring as a result of induction from currents flowing in the power conductors. In contrast, HVDC cables essentially only suffer from I^2R losses as the normally fixed nature of the impressed voltages and relatively constant current do not introduce any stray losses. The estimated losses associated with the three submarine cables considered are listed in Table 5.3 below.

Table 5.3 – Submarine cable losses

Cable Description	**No-load Loss (kW/km)**	**Load Loss (kW/km)**	**Total loss – at rated current (kW/km)**	**Weighted loss - 28% LLF (%/km)**	**Loss as a % of generated energy (%/km)**
132 kV, XLPE, 800 mm^2 Cu, three core	6	78	84	0.017	0.04
220 kV, XLPE, 800 mm^2 Cu, three core	14	76	90	0.014	0.03
450 kV, MIND, 1500 mm^2 Cu, single core	0	38	38	0.001	0.002

5.10.3 Onshore transmission

In addition to estimating the costs of submarine cable circuits, at this point it is also relevant, noting the potential lengths of onshore connection distances, to estimate the likely costs of continuing the connection using cable circuits or, alternatively overhead lines. Given the nature of the GB shoreline, particularly in the areas indicated on Figure 5.1, it is reasonable to assume that rural, green-field conditions will apply across most of the routes. The exception to this is likely to be associated with connections within Snowdonia, where more rugged terrain is anticipated.

SKM

Table 5.4 – Underground cable and overhead line costs

Cable Description	Supply cost (£/m)	Lay and bury (£/m)	Cable joints and extras (£/km)
132 kV, XLPE, 800 mm^2 Cu, 3 x single core	440	180	100,000
220 kV, XLPE, 800 mm^2 Cu, 3 x single core	530	200	100,000
450 kV, MIND, 1500 mm^2 Cu (per core)	275	150	100,000
132 kV, single circuit overhead line, 200 MVA		£ 300/m installed	
220 kV, single circuit overhead line, 300 MVA		£ 350/m installed	
+/- 450 kV, 1200 MVA dc overhead line		£ 200/m installed	

In the case of the underground cables referenced above, the losses associated with their operation will be similar to those listed in Table 5.3. In the case of the overhead lines, no load losses will be minimal and load losses at 200 MVA and 300 MVA respectively for the 132 kV and 220 kV lines will correspond to about 240 kW/km, and for the HVDC line, when operating at 1200 MW, to about 210 kW/km.

Table 5.5 – Overhead line losses

Type	Total loss – at rated current (kW/km)	Total loss – at rated current (%/km)	Weighted loss - 28% LLF (%/km)	Loss as a fraction of generated energy (%/km)
132 kV, single circuit overhead line, 200 MVA	240	0.12	0.03	0.075
220 kV, single circuit overhead line, 300 MVA	240	0.08	0.02	0.05
+/- 450 kV, 1200 MVA dc overhead line	210	0.018	0.005	0.0125

5.10.4 Onshore grid connection

5.10.4.1 Import using ac cables

At the onshore grid interface, the connecting equipment will comprise switchgear, to control the incoming generation connections and also the associated step-up transformers, in this analysis assumed to be connecting with the 400 kV grid.

Associated with the incoming circuit and in compliance with Grid Code requirements, variable reactive compensation equipment will be required. This should be sized to allow variation of incoming power factor between 0.95 power factor lead and lag. Additionally, shunt reactive compensation will also be needed to compensate for surplus capacitive charging current produced by the connecting cable circuit.

The grid side of the step-up transformer will be associated with a controlling circuit breaker, dependent upon the aggregate size of the incoming wind farm connections a number of transformers may be banked onto a single circuit breaker.

Based upon connecting a total of 800 MW of 132 kV wind farm connection, the total cost of the equipment referenced above will equate to about £40 million, i.e. £50/kW. In the case of say 900 MW of 220 kV connected wind farms terminating, these costs would total about £47 million, i.e. about £52/kW.

The losses associated with the onshore grid connection will be dominated by the main transformer losses and will approximate to those identified in Section 5.9.2. On rating, these are typically about 0.05 percent for the no-load losses and 0.2 percent for load losses, indicating a peak power loss of about 0.25 percent. However, when computed taking into account the envisaged utilisation of the transformers when carrying the wind farm output, typical loss load factor of about 28 percent, these losses equate to an annual loss of energy equivalent to 0.27 percent of generated energy.

In the case of the onshore grid connection however, additional losses will be incurred in the variable reactive compensation. Expressed in terms of the compensation equipment rating, these will correspond to about 0.1 percent when quiescent and about 0.4 percent when operating at the extremes of the control range. Assuming operation with the equipment moving between these extremes it is expected that average losses of about 0.15 percent will occur. However, when expressed in terms of the generated energy, a value of 0.12 percent is indicated, given an overall onshore grid connection loss of about 0.4 percent of generated energy.

5.10.4.2 Import using HVDC

If HVDC is used for the submarine transmission link, the bulk of the equipment referenced above will be replaced by an appropriate HVDC converter. The characteristics and cost of this converter will be similar to those detailed in Section 5.9.3 other than that due to the expected strong onshore ac network characteristics, some simplification of the conversion arrangements and associated capital cost savings should result. Accordingly, the estimated capital costs of a suitable 1200 MW HVDC converter, inclusive of any necessary filters and shunt capacitors and also controlling ac and dc switchgear, will correspond to about £79 million. However, in addition to the above a cost of about £24 million will be associated with the provision of variable reactive compensation equipment which will be needed to meet Grid Code requirements, given an overall onshore grid connection cost of £103 million, i.e. equivalent to about £86/kW.

Losses associated with the onshore HVDC converter are expected to be very similar to those described in Section 5.9.3.2, i.e. no load losses of about 0.1 percent, with full load losses increasing these by about 0.8 percent. Allowing for a Loss Load Factor of 28 percent, these losses equate to about 0.33 percent, expressed in terms of full load power. However, when expressed in terms of typical annual energy production (40 percent load factor), these losses equate to about 0.8 percent of total energy generation. However, in addition to these losses there will also be a similar level of losses associated with the reactive compensation equipment referenced above which, when expressed in terms of the generated energy, equate to a value of 0.12 percent. The result is an overall onshore grid connection loss of about 0.92 percent of generated energy.

5.11 Comparison of alternative offshore connection arrangements

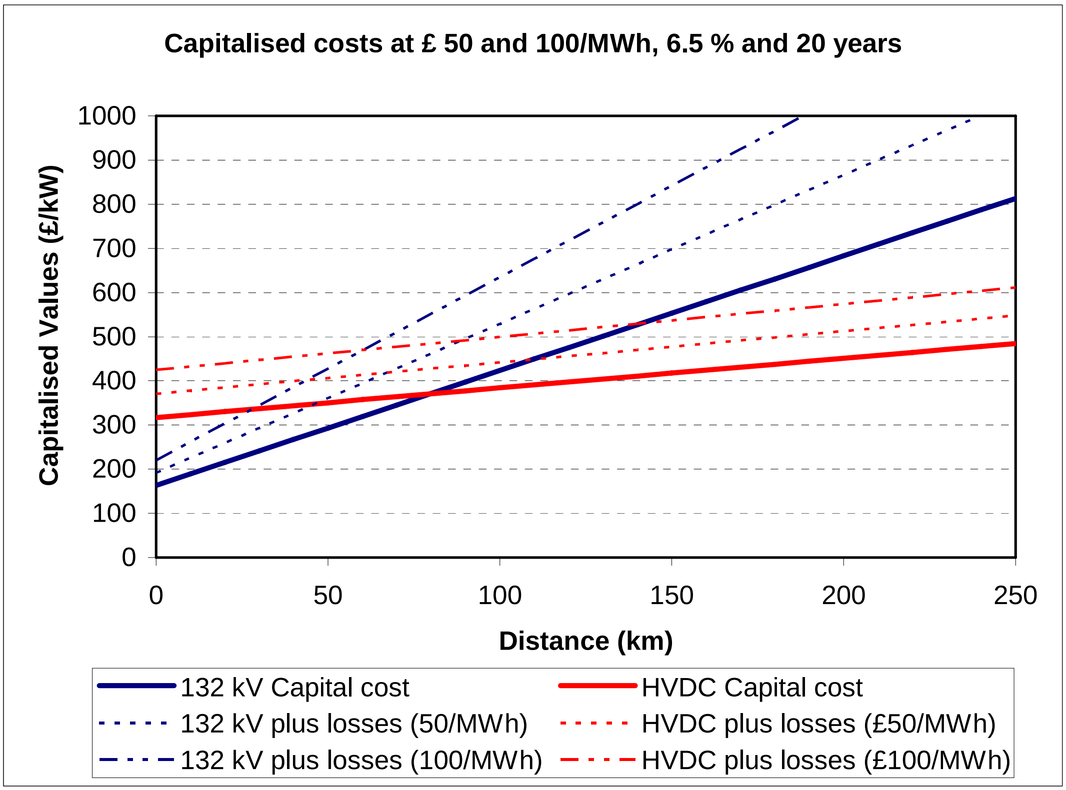
In the sections above, capital costs and associated power/energy losses have been determined for each of the main components involved in transmitting power from offshore wind farms into the MITS. These cost and associated losses are summarised in Table 5.6 below. It should be noted that the loss values presented in this table are based upon a single assumed wind farm annual energy characteristic which corresponds to a load factor of 40 percent and an associated loss load factor of 28 percent. Implicit within this analysis is also the assumption that the nominal capacity of the wind farm matches the available transmission capacity.

Table 5.6 – Summary of offshore generation connection costs and associated losses.

Element	Capital cost (£/kW) or (£/kW/km) – ac transmission	Capital cost (£/kW) or (£/kW/km) – HVDC transmission	Energy loss – ac transmission	Energy loss – HVDC transmission
Inter-array cabling	£50/kW	£50/kW	0.8 %	0.8 %
Offshore platform – common cost	£45/kW	£45/kW	0.27 %	0.27 %
Offshore platform – ac transmission	£15/kW	-	-	-
Offshore platform – HVDC transmission	-	£127/kW		0.8 %
Submarine cable link – common cost	£1.25/kW	£0.83/kW		
Submarine cable link - ac	£520/m = £2.6/kW.km	-	0.04%/km	
Submarine cable link - HVDC	-	£800/m = 0.67/kW.km		0.002%/km
Onshore grid connection – ac	£52/kW		0.4	
Onshore grid connection - HVDC		£86/kW		0.92

By plotting the equations presented above, the relative merits of 132 kV ac transmission and HVDC transmission can be assessed and the range of distances for which is best suited can be identified. The results of this analysis are presented on Figure 5.5.

Figure 5.5 – Comparison of alternative offshore transmission technology



It is clear from examination of Figure 5.5 that based solely on a comparison of capital costs, for offshore distances of up to about 75 km, the use of 132 kV submarine cable is indicated to be the most cost effective. However, when the value of losses is taken into account, initially at £ 50/MWh and then at £ 100/MW, the breakeven point between 132 kV and HVDC reduces to about 50 km.

5.11.1 Dogger Bank and The Wash

Reference to Figure 4.4 indicates that the above conclusions are particularly relevant to two of the prospective offshore wind farm locations, namely Dogger Bank and the additional capacity indicated for The Wash. Additionally, if as seems likely in the case of The Wash, the existing grid capacity at Walpole and on the associated overhead lines is fully utilised, then the required transmission distance will extends overland to the "Aire" and "Trent Busbars", refer to Figure 5.1.

Given the lack of any intervening transmission infrastructure there would seem to be a clear case for continuing with HVDC circuits overland, which further support the case for HVDC, noting that HVDC overhead line circuits would be more cost effective than 400 kV ac transmission in such a case and also less obtrusive than a double circuit 400 kV equivalent. Also, if sections of new circuits are require to be undergrounded for amenity reasons, HVDC cable circuits will also tend to be more cost effective and easier to manage than equivalent ac cables.

5.11.2 Thames and North West

In the case of the other offshore areas identified within Figure 4.4 and shown on Figure 5.1, namely developments in the Thames and in the North-West, the associated transmission distances indicate towards the use of ac transmission which would allow relatively convenient interfacing with the onshore grid.

5.11.3 Wales

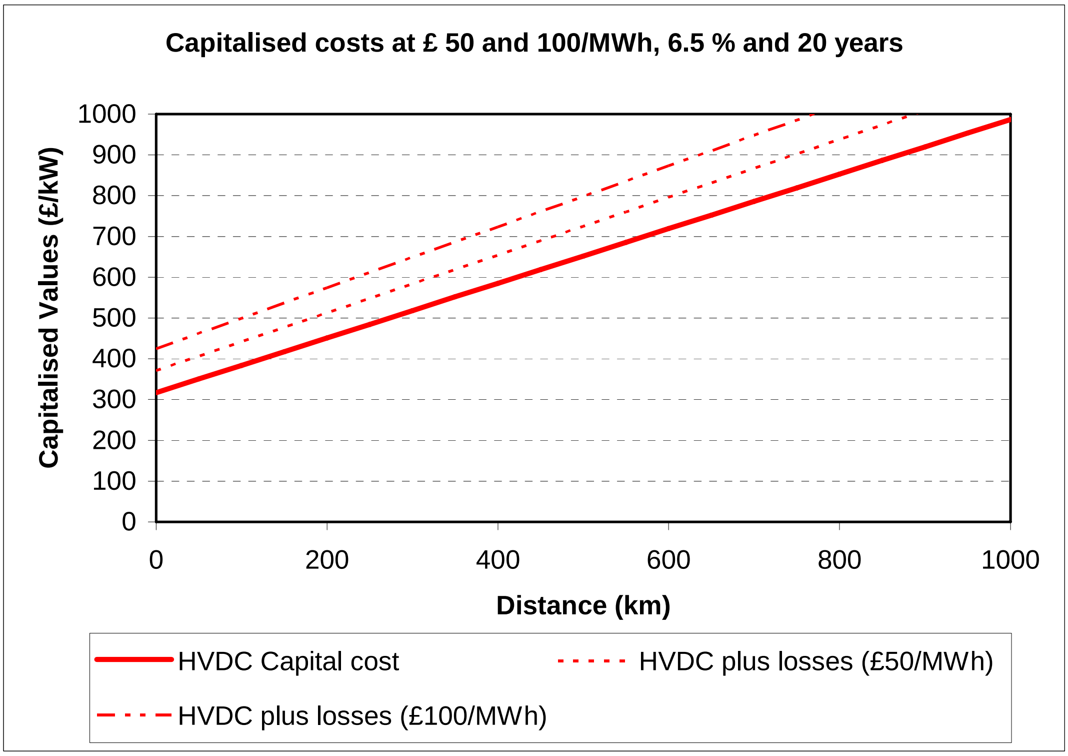
In the case of the indicated development in Wales, it is assumed that submarine cables will be able to land adjacent to the cable circuit linking the two pumped storage stations of Dinorwig and Trawsfynydd and that the circuit connecting back to Trawsfynydd, a relatively short (circa 6 km) cable circuit can be augmented such that access can be given to the relatively heavy duty (2 x 1,710 MVA) 400 kV circuits connecting to Legacy and Deeside. Given the likely changing role of pumped storage plant with increasing wind capacity, it is considered that reasonably complementary operation of the pumped storage and wind may be possible, hence minimising the need for any major reinforcements in this sensitive and important area.

5.11.4 Dogger Bank versus Scottish Islands.

It can be seen from Figure 5.5 that the costs of connecting with the Dogger Bank, circa 120 km to 180 km offshore will equate to about £500/kW when capitalised losses are included. This cost will be in addition to expected offshore WTG costs of about £1,800/kW. In comparison, onshore wind farms in high resource areas such as The Shetlands will be expected to have WTG costs of only about £1,100/kW, ie a saving of about £ 700/kW. The distance between the “Trent busbar” and The Shetlands, as an alternative to The Dogger Bank, is about 850 km, compared with between 120 km and 180 km (Figure 5.1).

To investigate the possible benefits of locating significant capacity on The Shetlands, we have extended the Figure 5.5 analysis to about 1,000 km transmission distance. The results of this extended analysis are presented on Figure 5.6 overleaf. Examination of Figure 5.6 indicates that the capitalised cost associated with such transmission amounts to about £1000/kW, an increase of about £550 MW for equivalent transmission to the Dogger Bank. In the early years of development of offshore WTGs, with the high risks to manufacturers and developers, it is likely that the increased WTG capital, and operational costs associated with offshore operation may outweigh the additional transmission costs referenced above.

Figure 5.6 – Extended HVDC transmission costs



6 Main Interconnected System

6.1 Introduction and summary of findings

This section investigates the effects of accommodating the levels of renewable generation indicated in the generation background scenarios presented in Section 3.1 on the operation of the Transmission System as a whole and also the reinforcements required on the onshore grid resulting from the connection of the levels of renewable generation required to achieve the 2020 targets under each scenario.

The operational studies have mainly focused on the effects of wind on network operation and security of supply. The results indicate that the system can accommodate the levels of wind under with relatively small operational impact.

The high level assessment of the capability of the network by 2020, based on the current network capability upgraded with the investments expected by 2014 as indicated in the 2007 National Grid Seven Year Statement (SYS), indicates that potentially the network would be able to accommodate the indicated levels of wind with few reinforcements. The majority of those reinforcements are ongoing, approved or planned, and are located in Scotland particularly in the north. The total capital costs of these reinforcements total over £1 billion.

This analysis is made at a high level as the specific locations of the wind farms, its capacities and the specific connection points in the network are subject of a large degree of uncertainty. It has also been assumed in some cases that some conventional generation in the north is displaced by generation in the south of the same technology and fuel type in order to avoid boundary constraints. Under the current trading arrangements however such generation redispatch would attract a financial operational cost which may not necessarily be reflective of the likely small differential marginal generation cost.

It is also possible that the volume of boundary constraints and potentially network investment that could be justified to accommodate renewables could peak during the interim period to 2020 as network congestion increases in certain areas following wind farm connections and the opportunities for certain generators to exert market power behind each constrained boundary. It is therefore considered timely the review of the transmission access arrangements and potentially it is also considered necessary to review the payments of network constraints and the network planning rules to consider explicitly wind generation and the balance of costs and benefits of network reinforcements.

6.2 Operational Issues

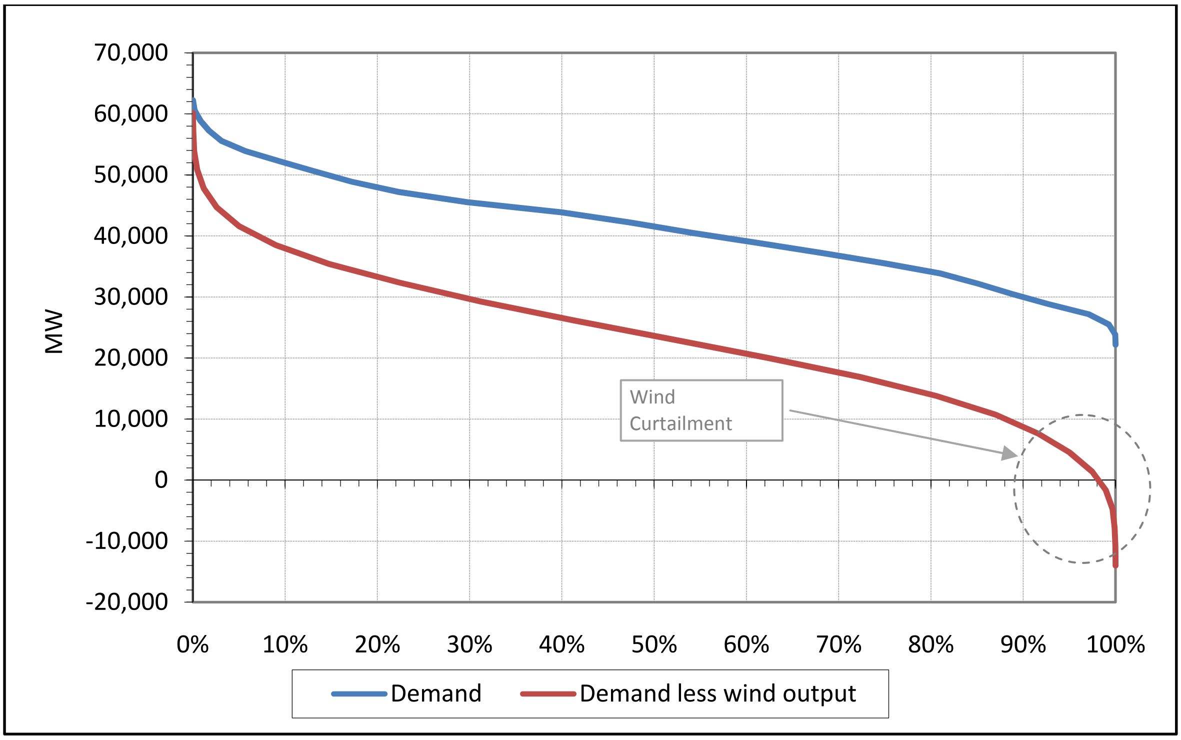
This section explores some operational issues that appear when the volume of installed wind capacity is comparable with demand. These are the ability of the system to accept wind output and the amount of conventional generation required to run to manage wind output variability.

6.2.1 Curtailment

When wind output exceeds demand wind has to be "curtailed", i.e. its output needs to be reduced. This situation may occur for the levels of wind considered under the renewable scenarios. Wind curtailment, when it occurs, can not be overcome by network reinforcements as it occurs because of operational reasons rather than because of network capacity congestion.

Figure 6.1 shows the annual cumulative distribution of demand (blue line) and also the cumulative distribution of demand less wind output (red line) or net demand for the *Higher Scenario*. It shows a probability of about 2% of "negative" demand, demonstrating the need for curtailment and the inability of the system to absorb all of the wind output. In practice however wind has to be curtailed much before its output equals demand as other conventional generation needs to be operating in the system mainly to maintain sufficient flexible generation to respond to the variability of wind output but also because of the inflexibility of certain "must run" plant, mainly nuclear generation.

Figure 6.1 Annual load duration curve of GB demand and demand net of wind output from half-hourly values for the Higher scenario (48 GW of installed wind capacity).



Energy storage and the export through international interconnections could potentially alleviate curtailment although in this latter case it would be subject to the ability of other countries (France and the Netherlands) to accept the excess wind energy in GB at the time. It is likely however that, given the close geographical proximity, those countries may be in a similar situation at the time i.e. low demands and high wind generation outputs and hence it can not be assumed that an interconnector would always result in reduced curtailment.

Table 6.1 lists the Pumped Storage stations currently available in the UK together with its maximum output and storage capacity.

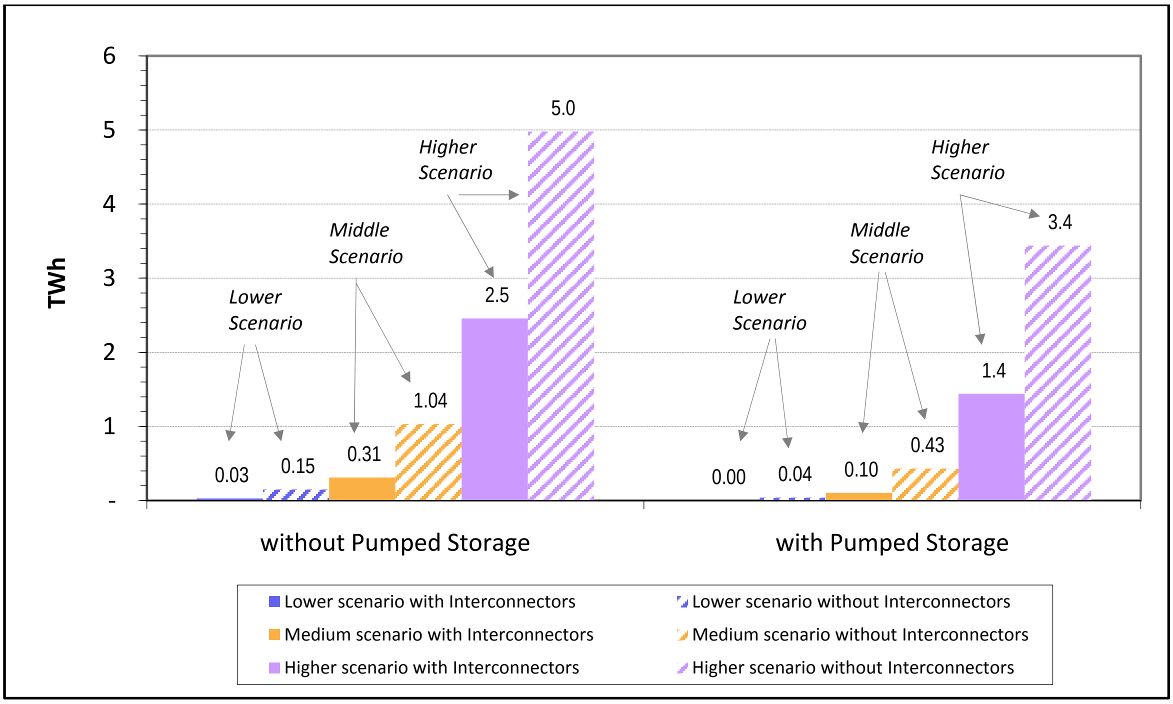
Table 6.1 Pumped Storage Stations in GB

Pumped Storage Station	Capacity (MW)	Storage (MWh)
Dinorwig	1,728	8,640
Cruachan	440	9,680
Foyers	300	1,800
Ffestiniog	360	1,440
Total	2,828	21,560

The impact of pumped storage on the level of curtailment required under the three renewable scenarios has been calculated. The assessment considered making use of the pumped storage stations and the interconnectors whilst maintaining an appropriate level of conventional plant to cope with wind intermittency and also considered limited flexibility from the nuclear power stations which stayed at a high output albeit with two units undergoing refuelling/ maintenance during the summer low demand period.

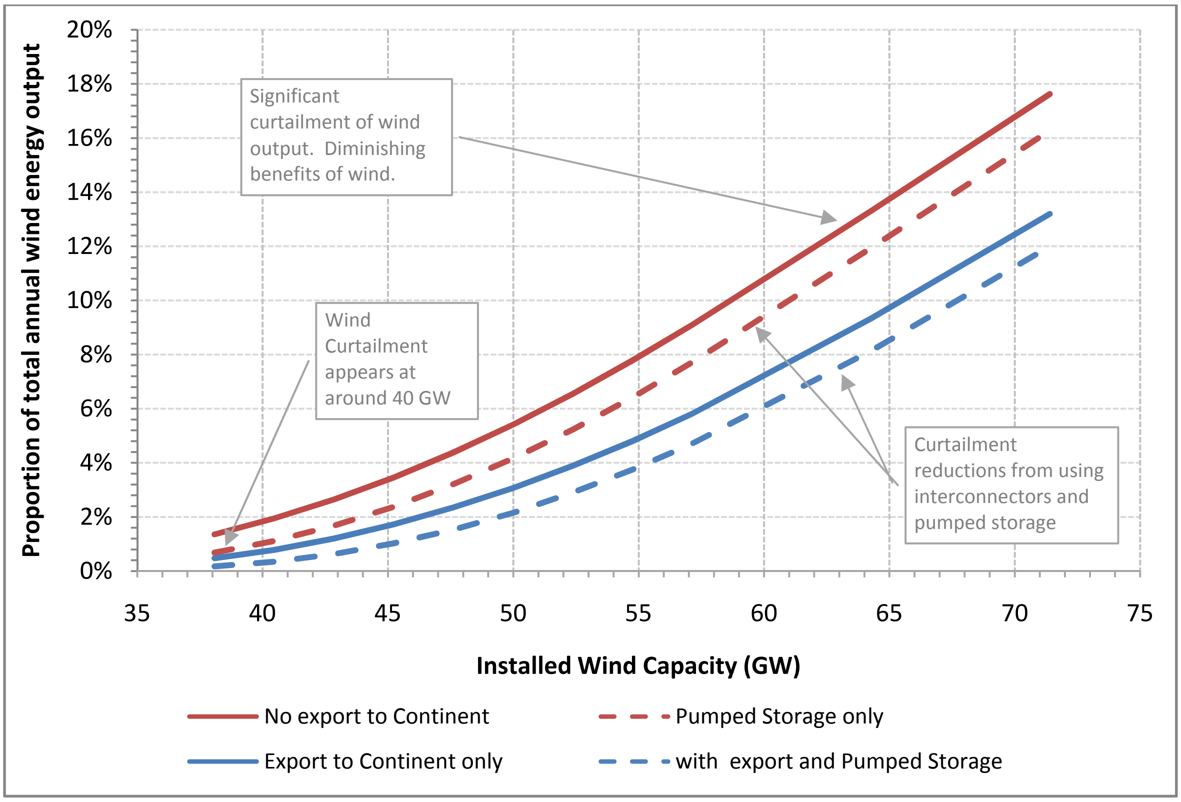
The results obtained are summarised in the following figure which shows the level of curtailment for each scenario under a combination of pumped storage and interconnector transfer assumptions. Figure 6.2 indicates that the levels of curtailed energy are negligible for the *Lower Scenario* but that it increases exponentially between the *Middle* and *Higher Scenarios*. Interconnectors are shown to provide a benefit to manage curtailment. Pumped storage can also be very effective to manage curtailment albeit it is limited by the amount of storage available. However these measures can not overcome the increase in curtailment volume expected for the *Higher Scenario* which could represent up to over 2% of the annual wind generation output.

Figure 6.2 Curtailment under the three Renewable scenarios



A further study was undertaken to establish the level of curtailment required when wind generation capacity is increased beyond the levels considered in the *Higher scenario*. Figure 6.3 shows wind curtailment, expressed as a proportion of the total energy output, as a function of the total installed capacity. The actual amount varies depending on the interconnector and pumped storage assumptions but in all cases it shows a fairly rapid rise reaching increasingly significant levels as the installed wind capacity grows above the *Middle Scenario* (about 39 GW). It should also be noted that the amount of plant required to manage wind intermittency also increases with installed wind capacity (Section 6.2.5).

Figure 6.3 Proportion of wind output curtailed as a function of installed capacity



It can be concluded from the above that when the installed wind capacity exceeds about 40 GW significant wind curtailment will be required. The level of curtailment, as a proportion of the total wind output, grows rapidly with installed wind capacity around this level. This physical limit indicates that diminishing benefits would result from increased wind capacities above this level.

6.2.2 Nuclear Generation

Curtailment increases with the amount of plant that needs to remain operating as demand reduces for a given amount of wind capacity connected. This includes those generating stations providing frequency response and/or reserve as well as other plant where to modulate its output is normally expensive or considered unsafe such as nuclear plant. It could then be concluded that increased amounts of nuclear plant in a system with high penetration of wind would invariably result in higher curtailment.

Implicit in the above assessment however is the assumption that nuclear power plant has limited flexibility. That design assumption would be sensible for large systems with a mixture of conventional plant, where nuclear generation would be amongst the lowest marginal cost plant and hence it would be normally operated as base load, i.e. at a high constant output for most of the time (excluding refuelling periods etc). The ability of nuclear plant to provide variable output or frequency response would not be used if the amount of nuclear capacity was relatively modest compared to the total demand. This is the case of the existing GB nuclear power stations.

There is evidence however that nuclear plant can be designed to vary its output if required. In the case of France there are currently 58 Pressurised Water Reactors (PWR) operating, representing about 70% of the installed generation capacity and such plant has to provide flexible output. In load following mode these reactors can vary its output between 25% and 100% of rated output[29]. Load following can be done twice a day acting directly on the nuclear reaction or/and the cooling system. In 2002, 48 PWRs in France operated in a load following mode[30].

The most recent nuclear plant in France (Flamanville 3, in Lower Normandy, EPR design currently under construction) will have considerable response capability[31] being able to maintain its output at 25% and then ramp up to full output at a rate of 2.5% of rated power per minute up to 60% output and at 5% of rated output per minute up to rated power. This means that potentially the unit can change its output from 25% to 100% in less than 30 minutes. However this unit is a 1,630 MW single shaft unit which may not be appropriate for the size of the GB system[32]. Although the nominal capabilities are considerable, it does not necessarily mean that it will be regularly operated in such mode as other considerations such as life reduction and safety may discourage full use of this capability. In France, in order to avoid premature wear, hydro and/or very large pumping stations will be generally preferred in order to control the frequency and/or to load follow.

The above indicates that it is technically feasible for future nuclear plants in GB to provide a considerable amount of flexible response if required. It can be concluded then that the increase in wind penetration in GB should not compromise the future for nuclear generation and vice versa

Figure 6.4 presents the amount of curtailed energy with flexible nuclear and compares the result to those presented in Figure 6.3. The results indicate a reduction of the amount of curtailed energy similar to that obtained by making use of the pumped storage stations. The benefits of flexible nuclear generation include not only the ability to reduce its output but also to provide reserve and frequency response under those circumstances.

---

[29] "Programmation pluriannuelle des investissements de production électrique", 29 Janvier 2002, Ministère de l'économie, des finances et de l'industrie

[30] "Rapport sur la durée de vie des centrales nucléaires et les nouveaux types de réacteurs", 13-14 mai 2003, Parlement français)

[31] "Rapport préléminaire de sûreté de Flamanville 3, version publique" , EDF, Pg 26 http://www.edf.fr/html/epr/rps/chap01/chap01.pdf

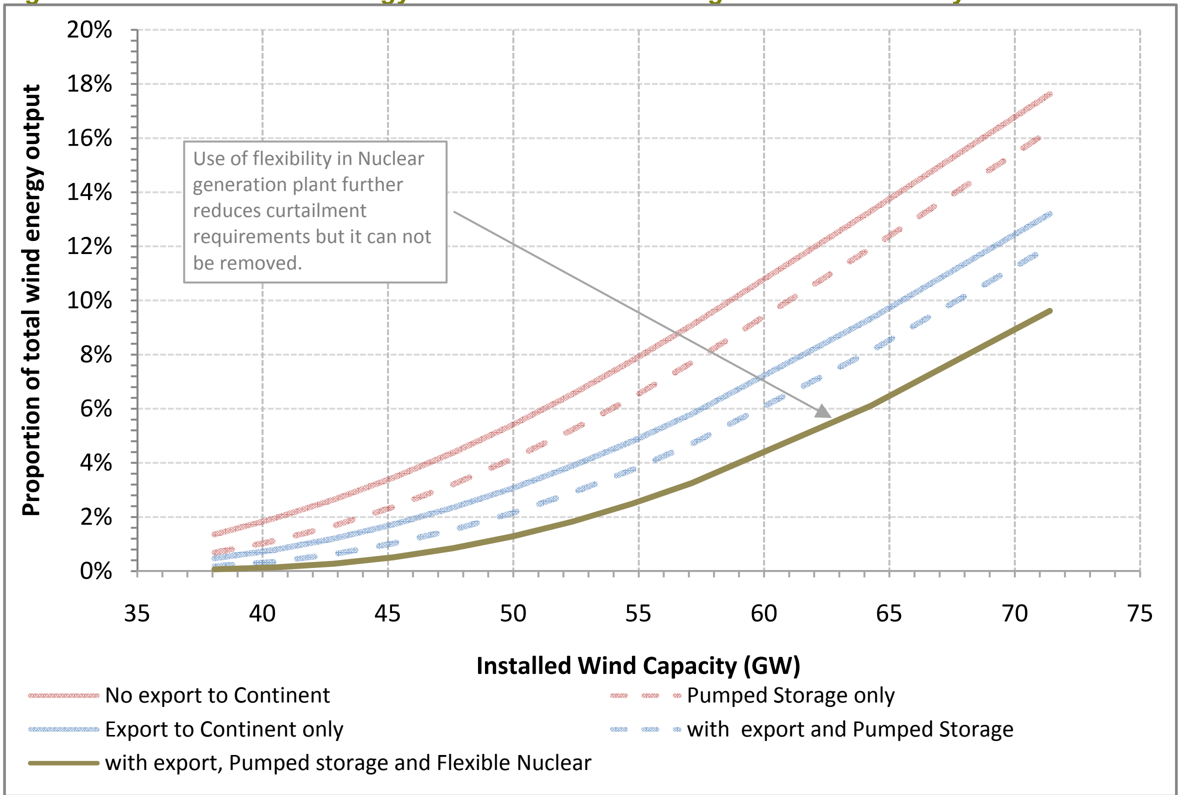
[32] Ofgem has recently initiated a review of the impact of larger generating units connecting in the GB system, "Impact of Larger Generating Units on GB Electricity Supply Frequency – Standards and Governance", Ofgem, May 2008

SKM

6.2.3 Wind and Nuclear curtailment alternatives.

The trade-off between wind and nuclear curtailment implicitly assumes there to be operational advantages associated with reducing nuclear rather than wind output, essentially that a rapid restoration of nuclear power output will be possible whilst such a capability may not available from wind. This largely reflects present WTG practice with minimal frequency control action being provided from such generation. In future more responsive WTGs may be available and more practical with the result that wind rather than nuclear generation may be curtailed noting that in either case curtailment effectively represents lost energy.

Figure 6.4 Effect on wind energy curtailment of Nuclear generation flexibility



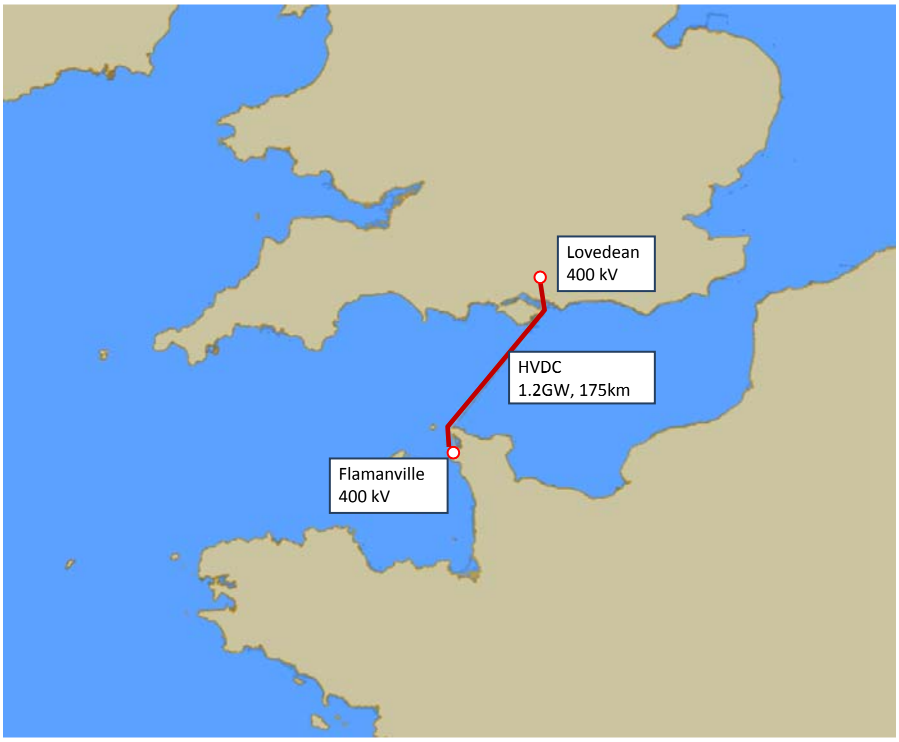
6.2.4 Demand Control

Implicit in the assessments presented in Sections 6.2.1 and 6.2.2 above is the assumption of no significant demand control or additional electrical energy storage whereas such control could be used to reduce otherwise wasted energy production and may also reduce reserve requirements at all times. Under wind/nuclear curtailment conditions such measures may become significantly more attractive to potential participants that it is the case at present. Hence some increase in domestic electrical energy storage and also industrial players such as water pumping works and similar (implicit energy storage) processors may allow better matching between demand and renewable generation. The benefits of such arrangements under the higher renewable scenarios would be expected to increase, and the costs and benefits of introducing such measures with increased renewable capacity should be the subject of further investigations.

6.2.5 International Interconnections

Section 6.2.1 demonstrated the benefit that international interconnections with the continent may bring to reduce curtailment requirements. Additional interconnectors could further reduce curtailment albeit subject to the ability of the importing system to absorb excess energy due to high renewable input and low demand. Additional benefits of international connections include the potential reduction of reserve and frequency control costs. However, for the levels of renewable capacity considered in the 2020 scenarios, the main justification for the construction of additional interconnections will be based on the differential average cost of energy between the GB and continental markets.

Figure 6.5 Example of possible additional international interconnection



In order to illustrate what this interconnection may look like Figure 6.5 shows a possible interconnection between the Flammanville area discussed in Section 6.2.2 above, which will host three nuclear stations, and a suitable point in the South of England (in this case the Lovedean 400 kV substation has been selected). The distance between those points has been estimated at around 175 km (by comparison the planned BritNed interconnector has a planned distance of over 250 km). Both end points are strong nodes of the respective transmission networks. The cost of the interconnection based on HVDC transmission over a distance of 175 km would be about £400 million for a 1,200 MW link which translates to a specific cost of about £340/kW. Considering that the generation costs in France will be dominated by nuclear power stations it is likely that the marginal costs would be in the range £5-10/MWh as indicated in Table 7.4. The interconnector cost above would add about £6/MWh to the marginal cost of nuclear which would still be below the next cheapest thermal generation technology. The same conclusion is obtained considering the levelised cost of nuclear with such interconnector compared with other technologies (Table 7.6)

It can be concluded that the imported energy from the continent, including the cost of the link but not considering some of the above benefits including the reduction in flows from the north of the country, would be competitive against the generation mix cost in GB as indicated by the expected generation costs results presented. In addition to the potential reductions in energy prices that additional interconnections could bring, additional benefits would be derived from the reduction in reserve, frequency control and curtailment costs.

6.2.6 Intermittency

Wind output is intermittent as it follows the fluctuations in wind speed. This short term variation of wind output has to be continuously compensated by other conventional plant in the system to maintain the generation-demand balance at all times. These variations will increase in magnitude as the amount of installed capacity increases, however it is unlikely that, in a large system with considerable wind penetration, all wind farms would increase or decrease its output simultaneously as the wind speed will vary throughout the country and the benefits of diversity will be apparent as discussed in Section 4.2.3.

In order to evaluate the effects of intermittency of wind generation on the plant required to provide frequency control a comparison has been undertaken between the variability of demand currently and the variability of demand net of wind generation using half hourly data for a three year period. Figure 6.6 shows the statistical distribution of half hourly variations of demand expressed in terms of MW change over a 30 minute period.

The distribution shows larger positive changes (demand increases) than negative changes (demand reductions). This observation is consistent with the large demand pick up that typically occurs between 6 and 9 am whereas demand reductions in the evening tend to be spread over a longer period. Figure 6.6 also shows that the maximum variability for demand increases over a half hourly period is about 5,000 MW. This has to be compensated by ramping up generation somewhere in the system which requires the generation to have been scheduled and in a suitable operating condition to provide reserve capacity. Demand reductions on the other hand are less problematic as they can be managed by simply by turning down and disconnecting generation.

Figure 6.6 Variability of demand and wind. Medium Renewables Scenario.

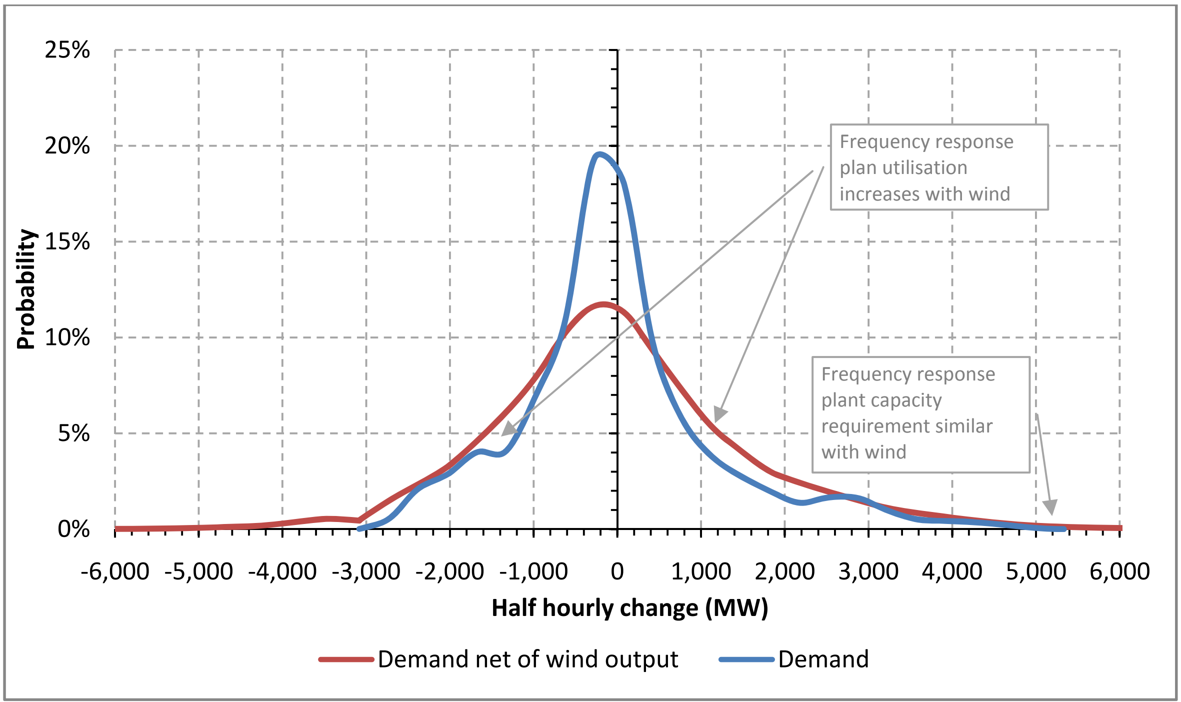


Figure 6.6 shows also the distribution of the "net demand" resulting from the deducting from the demand the wind output for each half hourly period using the three year demand and wind power output series. The resulting series indicate that the probability of large excursions is very small and the load-following requirements do not significantly increase over present requirements (without wind generation). Figure 6.6 also shows the effect of including wind in the shape of the distribution is also to make distribution more symmetrical, i.e. it becomes similarly likely to have increases as well as reductions in net demand as it could have been expected from the randomness of wind generation output.

It can be observed also that the statistical distribution of the ramp rates with wind is however above the one considering demand only (range 500 to 2500 MW). This indicates that, although no additional frequency response capacity may be required to cope with wind intermittency, it may be necessary to make use of increasing amounts of non-intermittent capacity for extended periods. This will cause an increase in the system operation costs that the system operator recovers through Ancillary Services.

6.3 Onshore Reinforcements

The connection of offshore and onshore wind farms could by 2020 change the patterns of the power flows across the existing network. The changes in the power flows would be dependant upon the location and connection points of the offshore and onshore wind farms as the geographical distribution of demand is unlikely to change significantly by then. Figure 4.2 and Figure 4.3

showed an approximate representation of the locations of the onshore and offshore wind farms respectively which amount to the majority of the renewable capacity, within the current electricity system.

6.3.1 Network conditions

The generation background scenarios discussed in Section 1 and the expected demand by 2020 have been combined to calculate the approximate flows through the network under two conditions for each of the three renewable scenarios namely:

1) Maximum demand and maximum wind output

2) Minimum demand and maximum wind output

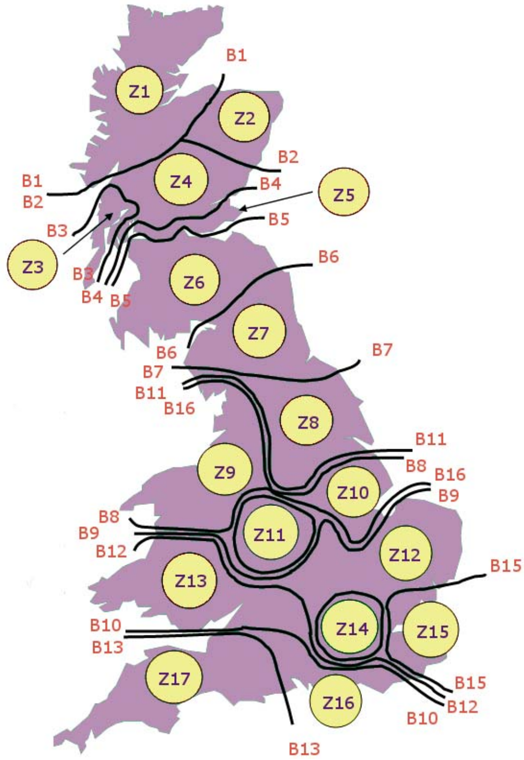
The case with minimum wind output has not been considered as currently with no renewables (or with a very small contribution) the network is currently capable of supplying demand. The focus of this part of the study is in identifying those reinforcements that are required to accommodate the indicated levels of renewable capacity.

In determining appropriate maximum wind output the scenarios have incorporated the conclusions from Section 4.2.8 namely that concurrent maximum wind output is about 85% overall as diversity effects make higher wind outputs very unlikely. It is possible however that higher output levels may be seen from certain areas but at the expense of reduced output from others. The sensitivity of the results to this issue will be further considered later in this section.

6.3.2 Approach and Modelling

In order to determine the capability of the current system with the proposed renewable generation locations and the potential for reinforcements, the power flows across the network in 2020 have been calculated across 17 critical network boundaries identified in NationalGrid's Seven Year Statement. These are shown graphically in the Figure 6.7 and the approximate boundary limits are shown in Appendix A.

Figure 6.7 GB Main transmission zones and limiting boundaries



The disposition of the generation capacity backgrounds within each zone broken down by technology type for the *Higher scenario* indicated in Section 4.5 is shown as an example in Figure 6.8. A detailed tabulation of the generation capacity assumed in 2020 in each zone comprising about 20 key generation technologies under each of the scenarios can be found in Appendix A

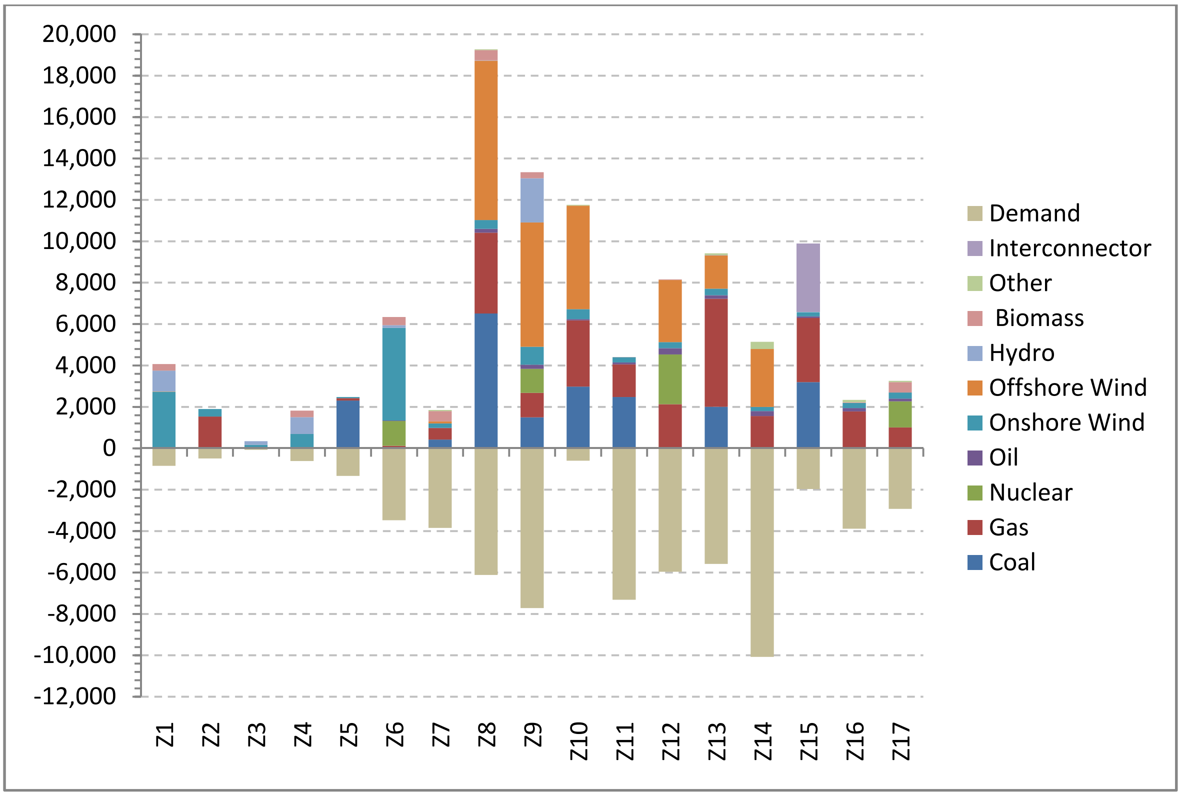
A dispatch study is undertaken based on generation marginal cost to establish a likely expected output from each generation technology based on an "economic dispatch". The resulting load factor for each generation technology is applied across equally across all zones in the country to obtain an initial output and hence power flow across each of the critical boundaries.

The boundary flow is then compared against each of the boundary limits to establish whether there is any violation. Any violations are normally the result of large north-south transfers between areas as demand is heavily concentrated in the south with considerable generation and particularly onshore wind located in the north and specifically in Scotland. In case that a violation appears then a number of dispatching options are investigated which include:

- Making use of pumped storage stations to storage renewable energy (wind) and relief some of the network power transfers

- Redispatch of conventional generation reducing its output to the "north" of the boundary violation and increase the output of similar technology located "south" of the boundary violation. As the generation involved in this redispatch is of the same technology (i.e. marginal cost), this transaction would theoretically result in a negligible economic cost, however, under the current market mechanisms, this type of transaction could attract a financial cost.

Figure 6.8 Allocation of generation and demand within boundary zones (MW), Higher



6.3.3 TIRG Reinforcements

It is important to note when considering the capability of the system that some important investments resulting from the expected levels of renewable connections are already being undertaken or approved and hence they are assumed to be available by 2020. Ofgem approved in 2004 a number of projects relating to the connection of renewable capacity in Scotland and Northern England. The status of these projects varies with some being in the construction stage whereas others, most notably the Beauly-Denny overhead line, going through the consenting stage. The projects reviewed by Ofgem, the location of them indicated in Figure 6.9 include:

- Beauly-Denny (£332 million)[33]
- England-Scotland connection circuits (£168 million)
- Kendoon (£40 million)
- Sloy (£21 million)
- North East England ring (£140 million)

Other projects such as Beauly-Keith, the Island connections or the Heysham ring were not initially funded by Ofgem. Since then some of the projects costs increased following detailed scoping and also the increase in commodities and unit costs. Some other projects not initially considered as "baseline" projects were approved on that basis.

6.3.4 Results

Appendix A shows the detailed assessment of the system flows in 2020. There are tables showing the generation dispatch under each scenario as well as tables with the flows across the limiting boundaries. In all cases system flows are kept within boundary limits following in some cases some redispatch of generation between boundaries. In one case a boundary violation in the London zone could not be removed by redispatch but a reinforcement in that area is already indicated as required by NationalGrid in their SYS without the level of renewables considered in this study.

Overall the most stressed area of the network was found in the north of the country and Scotland in particular. In this respect it was assumed that the wind generation in the islands connected also to appropriate connection points by extending the DC onshore part of the connection to Blackhillock and Keith. This has also been considered appropriate as connecting into Beauly may force to reinforce the existing 132 kV line between Beauly and Keith which would have to be rebuilt to a 400 kV specification. This reinforcement would require a consenting process similar to the current Beauly-Denny which would introduce significant uncertainty in the period to 2020.

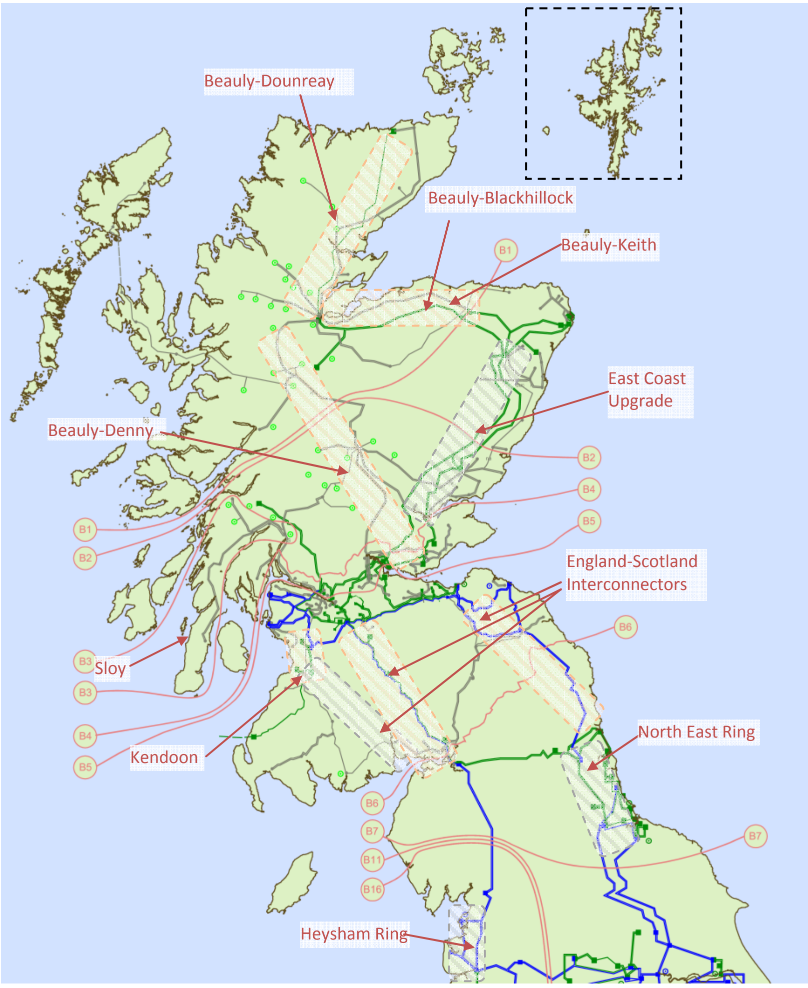
Notwithstanding the above, boundary margins in the north of Scotland were relatively marginal even after redispatch of some generation which makes some of these boundaries quite sensitive to the assumed level of renewable capacity and therefore certain reinforcements may be justified. The likely required reinforcements and estimated costs would be as follows:

- Beauly-Blackhillock reconductoring (£50m)
- Beauly-Keith rebuild (£200m)
- North of Scotland East coast 275 kV circuits upgrade to 400 kV (£90m)

[33] Capital costs in 2005 money and as originally approved by Ofgem. Additional impact of increased prices in Capital cost estimates were approved by Ofgem

Furthermore, in case of a much larger increase in the amount of wind capacity in Scotland over that assumed in the study, for example as a result of increased wind capacity in the Western Isles and/or Shetland, an additional reinforcement between Scotland and England may also be required. Assuming a connection between Kendoon and Harker it is estimated that the cost of such reinforcement would be around £80m. However this will impact on the network south of Harker and overall indicates the need for transmission reinforcements to the Mersey/Heysham and/or the North East ring. The more environmentally attractive alternative would be the use of HVDC submarine transmission down the east or west coast of Scotland depending upon the disposition of the additional renewable generation particularly if developed on the Scottish islands as an alternative to Dogger Bank (Section 5.11.4). The approximate location of some of the above discussed projects are shown in Figure 6.9.

Figure 6.9 Approved and planned renewable onshore reinforcements



It can be concluded from the above that even if the above reinforcements were justified the total costs are very modest compared with the amounts involved in the connection of offshore wind farms. The main issue becomes the deliverability of some of those reinforcements which, if required, under current regulations, would require going through the full permitting process that in recent experience has introduced considerable delays and uncertainty about the delivery of projects.

6.4 Regulatory Framework Considerations

Although the grid reinforcement costs associated with accommodating renewables are relatively small compared to the grid expansion costs, our analysis is based on a number of key assumptions that, if altered, may increase grid reinforcement costs:

- An element of foresight is assumed when assessing the impact of emerging renewable generation on grid development
- The generation assumptions used in the network planning criteria of the GBSQSS are modified to account for the reduced impact of intermittent generation particularly at times of peak demand
- Generation plant is dispatched on the basis of lowest short run marginal cost
- Potential congestion on the network is alleviated at least cost by the substitution of comparable generation – for example the reduction in output from a gas-fired plant due to network congestion is substituted by output from a gas-fired plant elsewhere on the network.

Assuming an element of foresight of renewable development over the period to 2020 ensures that uncertainty in grid development particularly to generation capacity location is minimised and hence leads to fairly optimal network development. In reality, over the interim period to 2020, renewable development may be more piecemeal. More piecemeal renewable generation may lead to higher grid reinforcement costs as conventional generation may only be 'displaced' when a certain capacity of renewable generation is reached. At lower levels of renewable capacity grid reinforcement may occur to accommodate the lower renewable capacity and the increasingly constrained existing conventional generation over the interim period to 2020.

The GBSQSS for transmission network planning has been historically derived for a system with a dominant conventional generation plant mix with no provision for increasing volumes of wind generation. As a result in the application of the GBSQSS the system operator may assumes that conventional plant remains operating at a relatively high load factor. Conventional thermal plant on a system with significant volumes of intermittent renewable generation however will have to operate at a lower load factor for a given demand. The average load factor of gas and coal-fired plant in the *Conventional scenario* is over 50%, in the *Higher scenario* it halves. Assuming that thermal plant operates at higher load factors, as in the existing GBSQSS, will lead to increased grid reinforcement requirements that may not necessarily be economic considering the long term network development. This is particularly applicable when considering the unprecedented change in the nature of the generation mix that could occur over the relatively short period to 2020.

The ongoing Transmission Access Review (TAR) is revaluating how generation capacity, in particular renewable capacity, can access the transmission network, including the role of the constraint payment mechanism, potential sharing of transmission capacity, non firm access and the potential tradability of access rights. The TAR is timely and we conclude that:

- The validity of some of the generation background assumptions indicated in the deterministic planning criteria of the GBSQSS should be revaluated when applied to a system with large penetration of wind generation;
- The TAR should seek to introduce a transmission access regime that encourages a longer term developmental view of the transmission network, rather than attempting to accommodate increasing volumes of intermittent renewable generation on piecemeal and therefore more costly basis.
- In the case of long generation connections involving submarine cables (e.g. Scottish islands) substantial system benefits may be derived from connection to suitable network sites rather than the nearest network point. A review should also be undertaken of the commercial incentives for developers of costlier connection alternatives that may result in either reduced network reinforcements and/or reduced connection uncertainty. The current system dilutes costs signals of infrastructure assets (i.e. most onshore transmission assets) between consumers and generating parties and the existing locational signal may not provide sufficient incentives for developers (or indeed network owners) to pursue such connection arrangements.

Finally and in addition to the above it will be necessary to simplify and shorten significantly the process to consent new overhead line circuits as recent experiences indicates that, even if additional reinforcements are justified, it will be almost impossible to get them built in time due to the complexities and duration involved in permitting new overhead line circuits.

7 Grid Costs

7.1 Introduction

The boundary flows analysis was based upon the economic dispatch of generation ranked in accordance to its merit order or marginal generation costs. This section summarises the generation costs associated with each of the three 2020 renewable scenarios that underpins the generation assumptions used in the previous section. In addition it also presents the total generation costs including the balancing costs that when added to the network infrastructure costs allows the calculation of the total grid costs associated with the generation portfolio. These costs include:

1. Generation Costs. Generation costs include both a variable and fixed element. Variable costs are dominated by the price of fuel used and the cost of any carbon permit required. Fixed costs are dominated by the capital cost of the generation plant required by 2020, together with an element of fixed operating cost.
2. Grid balancing costs. These are the additional costs imposed on the system to secure demand when wind output is low and manage wind intermittency.
3. Network infrastructure costs. Cumulative capital cost for the connection of the renewable generation required by 2020 in transmission and distribution networks and also the cost of network reinforcements of the transmission network in GB associated with renewable generation only.

It should also be noted that in this section all costs and prices are expressed in 2008 prices and undiscounted unless otherwise stated.

Table 7.1 Total Generation Capacity in 2020 (MW)

		Renewable scenarios		
Plant Type	**Conventional**	**Lower**	**Middle**	**Higher**
New coal	3,700	3,700	3,700	3,700
Coal	20,145	18,270	18,165	16,882
Gas	33,840	29,270	27,800	27,330
Nuclear	6,022	6,022	6,022	6,022
Interconnector	3,308	3,308	3,308	3,308
Other	6,722	6,762	6,762	6,762
Total non-renewables	***73,737***	***67,332***	***65,757***	***64,004***
Onshore wind	4,061	11,474	12,924	14,274
Offshore wind	740	21,562	25,712	34,212
Biomass	151	2,168	2,898	3,298
Other renewables	2,274	2,274	2,274	2,274
Total renewables	***7,226***	***37,478***	***43,808***	***54,058***
Total capacity	**80,963**	**104,810**	**109,565**	**118,062**

7.2 Generation Costs

The cost of generating electricity is determined by an assessment of the fixed and variable costs of operating a power station. The following generation costs are analysed in this section

- For existing plant that remains in service by 2020
    - Variable costs (mainly fuel)
    - Fixed Operating Costs

- For new plant installed in the period to 2020: Levelised costs which include
    - Variable costs (mainly fuel)
    - Operating costs (fixed and variable)
    - Capital costs

In addition to the above, some additional balancing costs have to be also included in the above.

7.2.1 Variable costs

Given that the variable costs of generation grow proportionally with output, marginal costs are equal to variable costs. The variable costs of most thermal generating plant are dominated by the cost of the fuel used in the power station – for the UK power system fuel costs are predominantly gas and coal.

Table 7.2 2020 Price assumptions

Type	Price
Gas (p/therm)	55
Coal ($/te)	110
Oil ($/barrel)	85
Biomass fuel (£/GJ)	3.6
Carbon permit (€/te CO2)	30

Table 7.2 shows the key price assumptions used for fuel prices and carbon permit prices in 2020 in all the scenarios. Gas and oil prices projections are based on the BERR Higher price projections from February 2008, together with our own coal price projection of $110/tonne delivered – this equates to an ARA price of around £47-50/tonne at a $2/£ exchange rate.

While the price of fuel dominates variable costs, smaller contributors include the cost of any carbon permit necessary to cover the resulting CO_2 emissions. While the cost of a carbon permit is not currently a major generating cost component, due mainly to the 'grandfathering' of emission permits, this is likely to change beyond 2012 when permits for the electricity sector may be auctioned in the EU Emissions Trading Scheme. The result will be that the cost of a carbon permit will become a more significant variable cost.

Table 7.3 Thermal plant variable generating cost components (£/MWh)

Cost components	CCGT	Coal FGD	Cleaner coal
Variable operating cost	0.3	1.55	1.6
Fuel	38	25.9	19.5
Carbon permit	7.3	19.1	14.3
Total variable costs	**45.6**	**46.6**	**35.4**

Table 7.3 shows the differing components that make up the variable generating costs of coal and gas generation in 2020 based on the price assumptions in Table 7.1. Clearly the cost of fuel remains the main component of variable costs for thermal generation. However, for coal fired generation in particular, the cost of a carbon permit becomes a key component in 2020.

Table 7.4 Marginal cost of generation by technology type (£/MWh)

Technology	Marginal Cost
Existing CCGT	52.1
New CCGT	45.5
Coal FGD	46.6
New coal	35.4
Biomass	56*
OCGT	69.1
Oil	91.1
Nuclear	5-10

*Before any ROC subsidy, currently around £40-45/MWh

The variable (marginal) cost of generation for a range of thermal and non thermal technology types is shown in Table 7.4. The marginal cost of generation for biomass excludes the impact of any renewable order certificate or similar subsidy – taking into account the ROC subsidy the variable cost of biomass would be in the order of £10-15/MWh. The dispatch model used dispatches generation on the basis of lowest short run marginal cost. Therefore the low marginal cost of nuclear and biomass (after accounting for the ROC subsidy) leads to their frequent dispatch. Similarly, the marginal cost of 'New coal' is relatively low given the higher efficiency of New coal technology.

CCGT and coal retrofitted with FGD have very similar marginal costs and as a result the point of economic substitution between the two technologies is finely balanced. The model used does not 'penny switch' between technologies. Therefore even though, based on the fuel and carbon permit price assumptions outlined in Table 7.2, FGD coal is marginally cheaper than new and existing CCGT, the model does not displace all gas with coal as we assume other factors are taken into consideration, including local emission limits, the requirement to maintain some 'standby' warm generation and the generation portfolios of the major market players.

7.2.2 Fixed costs

The fixed costs of existing generation that remains in service by 2020 will be relatively small given that capital costs will be largely sunk. The fixed costs of existing generation by 2020 will broadly amount to the equivalent fixed operating cost (FOC) of each technology type. While the FOC of differing technology types varies, we assign all existing plant based on cost information of existing generating plant a generic FOC of £35/kW/yr[34] to cover all fixed operating costs, including relevant labour and transmission energy capacity charges.

For new capacity the fixed costs are dominated by capital costs. Table 7.5 outlines the key cost assumptions for new plant used in the scenarios.

Table 7.5 New plant investment and cost assumptions

	New CCGT	New coal	Nuclear	Onshore wind	Offshore wind*	Biomass
Capital cost (£/kW)	500	1,050	1,400	900	1800	1800
Fixed operating cost (£/kW/yr)	23	34	35	35	69	60
Variable operating cost (£/MWh)	0.3	1.6	1.5	0	0	2.0
Plant efficiency (%)	55	46	36	-	-	50
Book life (years)	20	30	40	20	20	20
Lead time (years)	3	4	9	2	2	3
Discount rate (%)	10	10	10	10	10	10

*Does not include grid connection costs amounting to around £380/kW

7.2.3 Levelised costs of new plant

The present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments is the levelised cost of generation – this includes an assessment of fixed *and* variable costs. A uniform discount rate of 10 per cent has been assumed however the amortisation period and investment lead time used differs with each technology type. In order to assess the relative cost impact of the renewable scenarios we have evaluated the costs associated with a generating system that remains dominated by conventional capacity in 2020 with little additional renewable penetration – the *'Conventional' scenario*. The resulting lifetime levelised costs of generation for each new technology type are shown in Table 7.6

[34] Based on actual operating and fixed overhead costs of a coal fired power station with FGD. Includes £9/KW/yr of transmission charging costs assuming that the plant is located in the northern/middle of the country

Table 7.6 Lifetime levelised costs of plant added by 2020 (£/MWh)

		2020 Renewable Scenarios		
Technology	Conventional	Lower	Middle	Higher
New coal	56.4	57.4	58.7	61.1
New CCGT	56.5	58.5	59.8	62.8
Nuclear	37.9	37.9	37.9	37.9
Onshore wind*	65.7	60.4	60.4	61.6
Offshore wind*	87.8	86.4	83.4	81.7
Biomass*	95.6	95.7	96.5	101.7

*Before any ROC subsidy, currently around £40-45/MWh

The levelised cost of generation for each technology type differs between the scenarios due to the different load factors resulting for each technology type. Overall, as the load factor of new conventional plant declines over the period to 2020 with increasing penetration of wind generation, the levelised costs of new conventional thermal capacity increase.

For wind generation, as curtailment begins to take effect the load factor of onshore wind declines in the *Higher scenario*, as a result the levelised cost of onshore wind generation also increases. While the levelised cost of offshore generation is shown to decline in the *Middle* and *Higher scenarios*, this reduction would be greater if wind output was not curtailed.

7.2.4 Generation investment costs

The total investment required over the period to 2020 in the three renewable scenarios amounts to between £63 and £89 billion, as shown in Table 7.7. Total generation investment in the *Conventional scenario* is around £17 billion over the same period. Most of the generation investment required in the renewable scenarios is associated with offshore wind expansion.

Table 7.7 Generation Investment to 2020 (£ billion)

		Renewable Scenarios		
Technology	**Conventional**	**Lower**	**Middle**	**Higher**
Non-renewable generation				
New coal	3.9	3.9	3.9	3.9
CCGT	7.5	5.2	4.5	4.2
Nuclear	3.5	3.5	3.9	3.9
Total non-renewable	*14.9*	*12.6*	*12.3*	*12.0*
Renewable generation				
Onshore wind	0.4	7.1	8.5	9.6
Offshore wind	0.9	38.4	45.8	61.2
Biomass	0.0	3.6	4.9	5.6
Other	1.0	1.0	1.0	1.0
Total renewable	*2.3*	*50.1*	*60.2*	*77.4*
Total generation	**17.2**	**62.7**	**72.5**	**89.4**

7.3 Generating Plant Output

The generating plant output on the system in each scenario is determined by an economic generation dispatch model that dispatches generating plant by type to meet a given half hourly demand on the basis of lowest short run marginal cost. Wind generation has a near zero marginal cost and, other than when curtailed, it displaces conventional generation.

7.3.1 Output

Table 7.8 shows the output by plant type for each scenario and compares this output to the corresponding numbers in 2007. The contribution of renewables reaches the renewable targets under each of the 2020 scenarios.

The contribution of nuclear generation declines as capacity is retired and is not fully replaced by commissioning new capacity. The output contribution of gas-fired plant declines markedly, although total gas-fired generating capacity does not – reflecting the falling load factor. The contribution of coal-fired output also declines substantially, reflecting both the decline in coal capacity and the average annual load factor of coal-fired plant. The reduced output of Nuclear in the *Higher scenario* reflects a degree of flexing of the new nuclear to reduce wind curtailment by minimising fossil-fuel plant balancing requirements (Section 6.2.2). The contribution from the interconnectors increases to about 7% and reflects the expected lower (nuclear) generation cost in continental Europe compared to the GB average fossil fuel generation. It is considered that the relatively modest current interconnector utilisation in 2007, which is has been gradually reduced over the last few years, may also be the result of structural market issues[35] which may not be fully reflective of the underlying generation cost differentials between the continent and GB as indicated in the modelling of the 2020 scenarios.

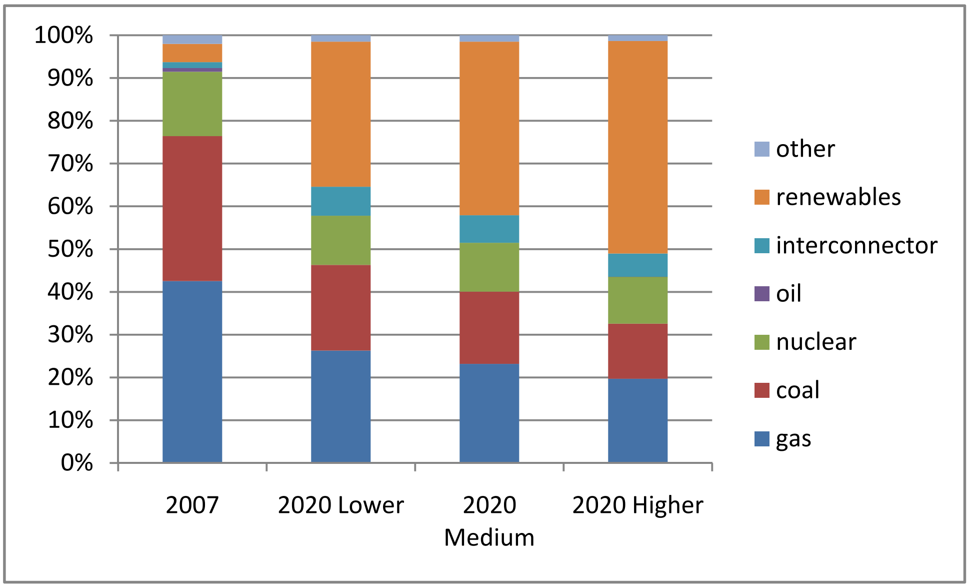
Table 7.8 Generation output by technology, TWh

		2020	2020 Renewable scenarios		
Type	**2007**	**Conventional**	**Lower**	**Middle**	**Higher**
Gas	160	169.8	98.4	86.7	74.2
Coal	128	106.1	75.0	63.2	48.9
Nuclear	56	43.0	42.9	42.8	40.9
Oil	3	0.0	0.00	0.00	0.00
interconnectors	5	25.9	25.4	24.1	19.9
renewables	**16**	**24.1**	**127**	**152**	**186**
Other	7	5.6	5.7	5.6	4.6
Total	**375**	**375**	**375**	**375**	**375**

[35] "Competition Report on the GB Gas and Power Markets", Energwatch discussion paper, April 2008.

Clearly the contribution of renewable generation increases substantially as the renewable targets for each scenario are met. In 2020 renewables supply 34% of electricity delivered to the system in the *Lower scenario*, 41% in the *Medium scenario* and almost 50% in the *Higher scenario* (Table 7.8 and Figure 7.1).

Figure 7.1 Generation portfolio output mix



It should also be noted from Table 7.8 that the reduction in gas and coal output per additional unit of renewables is not constant between the conventional and each of the renewable scenarios. Table 7.9 shows the reduction of gas and coal output relative to the increased renewable output in all the 2020 renewable scenarios relative to the conventional scenario. It can also be seen from further inspection of this table that the incremental reduction in the *Higher scenario* reduces relative to the delivered renewable production which is the result of increased curtailment.

Table 7.9 Reduction in output per increased renewable compared to the conventional scenario

	Renewable scenarios		
Type	Lower	Middle	Higher
gas	69%	65%	59%
coal	30%	34%	35%

7.3.2 Load factor

Given that total generating capacity increases in each of the three renewable scenarios but total demand does not, the resulting plant utilisation (load factor) declines. The technology load factors for onshore and offshore wind, after taking into account curtailment, are shown in Table 7.10.

Clearly, as wind curtailment increases the load factor of wind generation is adversely affected, this phenomenon is clearly illustrated for wind, where the load factor declines to around 26 per cent in the *Higher scenario* and is also concealed with the offshore load factor which includes a significant contribution from the wind in Dogger Bank with high load factor. Without curtailment the offshore load factor in both the *Middle* and *Higher scenario* would be greater. Table 7.10 also shows that the load factor of the interconnector declines in the *Higher scenario* – this is a reflection of the impact of wind curtailment. Given that wind generation has a near zero marginal cost, at times of potential curtailment wind generation is exported through the interconnector. In addition pumped storage is assumed to take advantage of the surplus wind energy and pump water. Both these measures serve to increase effective demand and thereby limit the extent of curtailment. However, these measures are not enough to eliminate curtailment in the *Higher scenario* – this result suggests that, as wind capacity increases above the level indicated in the *Middle scenario*, diminishing returns will set in.

Table 7.10 Annual generation load factors by technology in 2020

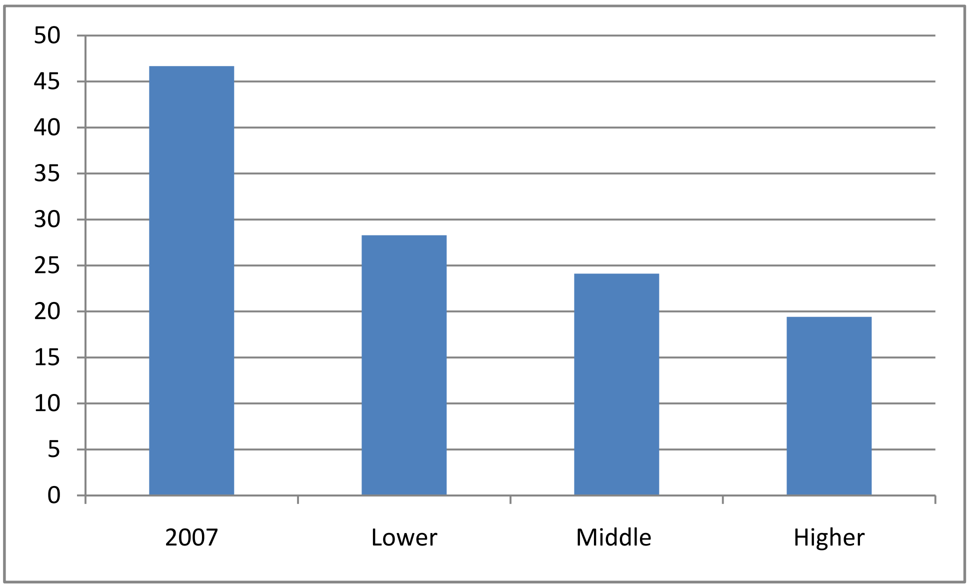
		Renewable scenarios		
Type	Conventional	Lower	Middle	Higher
New coal	83.7%	83.7%	78.7%	71.6%
FGD	49.1%	33.8%	27.2%	20.0%
CCGT/gas	54.8%	33.9%	31.2%	26.5%
CHP	89.3%	88.8%	85.8%	77.5%
Nuclear	81.5%	81.5%	79.3%	74.3%
Onshore Wind	25.7%	27.9%	27.9%	27.3%
Offshore Wind	38.2%	38.9%	40.2%	41.1%
Biomass	84.3%	84.2%	82.5%	73.3%
Interconnector	89.3%	87.7%	83.0%	68.5%
Other	2.6%	0.8%	1.2%	1.4%

The load factors of each plant type are also shown in Table 7.10. Overall, as the penetration of wind generation increases, the load factor of all other plant declines. As a result in the *Higher scenario* the load factor of CCGT plant has declined to 26 per cent and that of the coal plant with FGD has declined to 20 per cent. Given that nuclear has a low fuel costs and a subsequent low short run marginal cost, nuclear is dispatched before coal or gas-fired plant and therefore maintains a higher average annual load factor than coal or gas-fired generation.

7.3.3 CO_2 emissions

In all scenarios CO_2 emissions from the electricity sector decline significantly. Figure 7.2 shows the resulting emissions in each scenario. The greatest reduction in emissions occurs in the *Higher scenario*, with emissions from the electricity sector less than half the current level.

Figure 7.2 CO_2 emissions (MtC)



7.4 Generation cost

In order to determine a 'total' generation cost for each scenario in 2020 an assessment of fixed and variable costs for new and existing plant has been made. Table 7.11 shows the total generation costs expressed in pounds per MWh of delivered energy for the scenarios considered. The cost of new capacity over the period to 2020 is the lifetime levelised cost of each technology type. The cost of existing plant is assessed using its variable costs and fixed operating costs.

Table 7.11 Total weighted average generation costs by 2020

	Capacity (GW)			
Scenario	**Existing in 2008 available in 2020**	**New capacity to 2020**	**Total**	**Total costs (£/MWh)**
Conventional	56.2	24.7	80.9	48.5
Lower	55.0	50.3	105.3	58.2
Middle	54.8	55.3	110.1	59.8
Higher	53.6	65.0	118.6	63.2

The increase in costs is smaller between the *Lower* and *Middle scenarios* than the *Middle* and *Higher scenarios*. These results suggest that the cost of incremental renewable capacity above the *Middle* begins to rise more quickly. The rising incremental costs are a function of the need to begin curtailing wind in the *Higher scenario*, leading to the construction of additional renewable capacity to meet the scenario target.

7.5 Balancing Costs

The introduction of significant volumes of intermittent wind generation into an electricity system will generally increase the balancing costs of that system. Balancing costs can broadly be divided into the following two groups:

- System operation balancing costs – this relate to the relatively rapid short term adjustments that must be made to the generation output in order to manage the variability of wind output. Such balancing is required given that electricity supply and demand must balance in real time. Balancing costs are therefore short term costs incurred over the time period from minutes to hours. An additional cost associated with managing wind variability is the possible reduction of efficiency of conventional plant as it moves away from its maximum efficiency operating point.
- Balancing plant enabling costs– these costs are those associated with ensuring that the sufficient installed generating capacity remains in service to secure demand demand to cope for the periods when wind output is low. Section 7.3 showed the declining load factor of some key non-renewable plant that is essential to secure demand in case of low wind output at times of high demand.

7.5.1 Short term balancing costs

The increase in the balancing requirement of an electricity system with large volumes of intermittent generation (mainly wind) will be a function of the level of wind penetration, the underlying generation mix and the marginal costs of mitigating the increased output variability associated with wind. We estimate, based on the marginal cost of the generation required to respond to wind output variability, the balancing cost of intermittent generation will vary from £4.5/MWh in the *Lower scenario* to £6.5/MWh in the *Higher scenario* (Table 7.12)

Table 7.12 Short term balancing costs

Scenario	Wind output (% total)	Balancing costs (£/MWh)
Conventional	3.1%	0.7
Lower	27.1%	4.5
Middle	32.7%	5.3
Higher	42.0%	6.5

It should be noted that the balancing costs indicated in Table 7.12 are included in the average total generating costs indicated in Table 7.11.

7.5.2 Balancing plant enabling costs

Given the intermittent nature of wind generation a certain volume of ‘back up’ or ‘shadow’ capacity must be available to the system to ensure security of supply on top of the required plant margin. Given that no explicit capacity payments mechanism exits in BETTA and generators self dispatch, this shadow capacity will be remunerated either via payments to the relevant generator's overall portfolio or made through the ancillary service market via bilateral contracts with the system operator.

In order to assess the costs associated with maintaining shadow plant and the differences between the scenarios, we determine the volume of capacity that does not operate throughout the year and assign this capacity a fixed operating cost of £35/kW/yr (Section 7.2.2). The cost of this plant is not wholly associated with the impact of increasing volumes of wind as a certain volume of plant is required to maintain security of supply (the plant margin), but the increasing volume of the plant margin and the associated cost across each scenario is shown in Table 7.13.

Table 7.13 Cost of plant margin

Scenario	Non operational *capacity (GW)*	Annual cost (£m)	*Cost (£/MWh)*
Conventional	10.4	364	0.97
Lower	19.5	680	1.82
Middle	21.3	715	1.91
Higher	23.9	840	2.24

The total resulting balancing costs for each scenario obtained from the results in Table 7.12 and Table 7.13 are shown in Table 7.14. Clearly, as the volume of wind generation increases, then the cost of system balancing subsequently increases.

Table 7.14 Balancing costs

Scenario	Short term balancing costs (£/MWh)	Other intermittency costs (£/MWh)	Total balancing costs (£/MWh)
Conventional	0.7	0.97	1.67
Lower	4.5	1.82	6.32
Middle	5.3	1.91	7.21
Higher	6.5	2.24	8.74

7.6 Generation Connection costs

7.6.1 Offshore wind Generation

Table 7.15 shows the connection costs for the offshore wind farms considered under each of the 2020 renewable scenarios broken down by each of the main regions considered in the study. The results also indicate two alternatives namely the use of underground cable or overhead line for the onshore portion of the connection infrastructure.

Table 7.15 Offshore Wind Connection costs (£ million)

				Connection Cost (£ million)					
	Capacity (GW)			Using OHL onshore			Using UGC onshore		
Location	Lower	Middle	Higher	Lower	Middle	Higher	Lower	Middle	Higher
Wash	8.0	8.0	8.0	3,050	3,050	3,050	3,303	3,303	3,303
North West	6.0	6.0	6.0	1,478	1,478	1,478	1,694	1,694	1,694
Thames	2.8	2.8	2.8	1,125	1,127	1,127	1,226	1,228	1,228
Wales	1.5	1.5	1.5	423	423	423	454	454	454
Dogger	3.6	7.7	15.2	1,544	3,527	6,713	1,697	3,884	7,388
Others	0.2	0.2	0.2	46	46	46	51	51	51
Total	**22.1**	**26.2**	**33.7**	**7,666**	**9,651**	**12,837**	**8,425**	**10,615**	**14,119**

The results indicate significant capital expenditure requirements between £8 billion and £14 billion for the *Lower* and *Higher scenarios* respectively. These costs are up to almost half of the modern equivalent replacement value of the entire existing transmission network in Great Britain[36].

Table 7.16 Total offshore wind connection specific costs

				Average Specific Cost (£/kW)					
	Capacity (GW)			Using OHL onshore			Using UGC onshore		
Location	Lower	Middle	Higher	Lower	Middle	Higher	Lower	Middle	Higher
Wash	8.0	8.0	8.0	381	381	381	413	413	413
North West	6.0	6.0	6.0	246	246	246	282	282	282
Thames	2.8	2.8	2.8	409	403	403	446	439	439
Wales	1.5	1.5	1.5	282	282	282	303	303	303
Dogger	3.6	7.7	15.2	429	458	442	471	504	486
Others	0.2	0.2	0.2	216	216	216	242	242	242
Total	**22.1**	**26.2**	**33.7**	**347**	**368**	**381**	**382**	**405**	**419**

The offshore wind connection costs expressed in £/kW are shown in Table 7.16. In the case of using underground cable for the onshore part of the connection the specific cost range between about £380/kW in the *Lower scenario* to £419/kW in the *Higher scenario*. The increase in average specific cost is the result of the increased capacity in Dogger Bank which has an average specific cost of around £485/kW, the scenario variability being associated with the discretional nature of network capacity.

Expressed in terms of annual transmission charges, and assuming a cost of capital of 6.5% and 40 years depreciation period consistent with the assumptions in the last transmission price control, the average annual transmission charges cost resulting from the above would be between £24.5k/MW (*Lower Scenario* using OHL onshore) and £29.6k/MW (*Higher Scenario* using UGC onshore). These charges increase to £35k/MW and £38k/MW respectively for a 20 years return period.

[36] Energy Networks Association "Long Term Capital Expenditure Forecasts for the Electricity Network in Great Britain", http://2008.energynetworks.org/long-term-scenarios/, Sinclair Knight Merz, July 2007

Table 7.17 shows the total lengths of AC and DC cables required under each of the renewable scenarios (excluding the interarray cables within the wind farm) broken down by section (offshore and onshore) and offshore area. The lengths are significant ranging from over 1,500 km of AC cable and 3,200 km of DC cable in the *Lower scenario* to over 7,400 km of DC cable in the *Higher Scenario* and will represent a considerable manufacturing challenge.

Table 7.17 Underground Cable lengths

	Lower				Medium				Higher			
	AC		DC		AC		DC		AC		DC	
Area	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore
Wash	0	0	910	595	0	0	910	595	0	0	910	595
North West	900	100	0	0	900	100	0	0	900	100	0	0
Thames	250	10	200	200	250	10	200	200	250	10	200	200
Wales	320	18	0	0	320	18	0	0	320	18	0	0
Dogger	0	0	900	360	0	0	2,100	840	0	0	4,080	1,590
Others	25	20	0	0	25	20	0	0	25	20	0	0
Total	1,495	148	2,010	1,155	1,495	148	3,210	1,635	1,495	148	5,190	2,385

7.6.2 Onshore renewables

Onshore renewables will be predominantly embedded in the distribution system in England and Wales and within the 132 kV transmission system in Scotland. t is not practical to undertake a bottom up analysis of the connection costs as each project will be highly dependant on local issues and distances to suitable connection costs. It is therefore considered appropriate for the purposes of this project to estimate the grid costs associated with onshore renewables based on an average specific cost (£/kW)

During the last distribution price control review the distribution companies were asked to provide details about their actual/forecast connection costs for distributed generation (DG) under DPCR3 and to forecast future connection costs for the current price control period[37]. The results indicated average costs of about £40/kW under DPCR3 to connect circa 3.1 GW and expected costs between £83-103/kW for DPCR4 to connect around 10 GW of additional distributed generation. Wide variations in average connection cost forecasts were visible between DNOs as a result of the range of scheme sizes and the specific network locations of each of the projects within each DNO. The results indicated an average capital expenditure projection of about £66/kW on dedicated connection assets and £35/kW on shared assets with an average DG total connection cost of £100/kW.

[37] Electricity Distribution Price Control Review. Update. October 2003. Ofgem, www.ofgem.gov.uk.

Based on the above and considering the rise in costs since the time when that information was consulted upon it has been considered appropriate to use an average connection cost of £125/kW which compares very favourably with the circa £400/kW costs for connecting offshore wind.

7.7 Total costs including grid costs

Table 7.18 shows the total costs of each scenario including those costs associated with grid expansion and reinforcement expressed as an average £ per MWh of delivered energy. In general terms, as the penetration of renewables increases so do grid costs given that most of the additional renewable expansion is offshore wind.

Table 7.18 Total Costs and Benefits of the 2020 scenarios

		Renewable Scenarios		
	Conventional	Lower	Middle	Higher
New Generation capacity (£ billion)				
Renewable Capacity	2.3	50.1	60.2	77.4
Non- Renewable Capacity	14.9	12.6	12.3	12.0
Total	*17.2*	*62.7*	*72.5*	*89.4*
Network (£ billion)				
Offshore wind connection	0.0	8.4	10.6	14.1
Onshore wind connection	0.1	1.0	1.2	1.4
Other reinforcement	0.8	0.8	0.8	0.8
Total	*0.9*	*10.2*	*12.6*	*16.3*
Total Grid Investment Costs (Generation+network)	**18.1**	**72.9**	**85.1**	**105.7**
Marginal Generation cost	35.9	25.0	22.6	18.9
Cost per MWh produced (£/MWh)				
Generation costs (Fixed and variable)	46.8	51.9	52.6	54.5
Balancing and intermittency	1.7	6.3	7.2	8.7
Grid expansion for renewables	0.1	3.5	4.1	5.2
Total Cost including network (£/MWh)	**48.6**	**61.7**	**63.9**	**68.4**

These results suggest that, for the three renewable scenarios analysed, there are diminishing returns associated with increasing wind generating capacity above the levels outlined in the Middle scenario as the impact of curtailing wind generation begins to take effect.

The following table shows the cost per tonne of CO_2 abated, reflecting the incremental cost of moving from the *Conventional scenario* to each of the renewables scenarios. The cost of carbon abatement in the Lower Scenario relative to the conventional scenario amounts to around £85/te CO_2. The cost of carbon reductions in the Middle scenario falls to £80/te CO_2. In the higher scenario the cost of carbon abatement begins to rise to £83/te CO_2.

Table 7.19 Incremental cost of carbon abatement

Technology	Conventional	Renewable Scenarios		
		Lower	Middle	Higher
Carbon Emissions	44.0	28.3	24.3	19.4
Cost of carbon abated (£/te CO_2)	-	85	80	83

The main difference between the three renewable scenarios is the amount of capacity in Dogger Bank. The higher abatement cost in the *Lower scenario* compared to the *Middle scenario* in Table 7.9 is explained by the reduction in specific cost of the renewable energy even after the inclusion of the network connection costs. This is the result of the high load factor from Dogger Bank (Table 7.10) which even after the inclusion of the network connection costs in Table 7.16 results in a falling cost of renewable energy (£/MWh) with increased capacity (not considering curtailment in the *Higher scenario*). This is because the higher network connection costs are more than compensated by the higher load factor. However this result is based on using a discount rate of 10% across all wind projects as indicated in Section 7.2.3. If the development of Dogger Bank were to attract a higher risk premium considering its remoteness and capital requirements then the specific cost would increase from the Lower to the Higher scenario as expected.

7.8 Conclusions

The total cost of an electricity system with significant renewable generation, including associated grid expansion, will cost at least 25 per cent more than a 'conventional' system. As the penetration of renewables increases, costs also increase. With 50 per cent of electricity supplied to the system delivered from renewables – the *Higher scenario* – total costs in 2020 are some 40 per cent higher than a conventional system.

In terms of cost per tonne of CO_2 abated, there are diminishing returns associated with increasing the renewable target beyond about 40 per cent (the *Middle scenario*) as the cost of carbon abated begins to rise. This reflects the need to begin 'curtailing' wind output at higher levels of renewable penetration because the system cannot physically accept, in some periods, all the output of wind and keep within adequate operating parameters.

Most of the capital costs of renewable investment are associated with developing offshore wind and the greatest costs are associated with wind farms in Dogger Bank that it is believed will be required to deliver the scenario targets. The magnitude of the investment required and the risks in developing such novel site with a long electrical connection will only be attractive to very financially strong utilities which then may then require significant capital risk premiums, over those assumed in this study, to commit to the projects. As a result, the total cost of delivering the renewable scenarios outlined may be higher.

Appendix A Boundary Flows Analysis

A.1 High Wind, Peak Demand – Low Scenario

A.1.1 Available capacity

Sum of 2020/21 Capacity (MW)	SYS Study Zone																	
Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	**Total MW**
Biomass	270	0	0	265	0	297	310	310	295	0	11	31	0	0	0	28	350	2,168
CCGT	0	1,524	0	0	0	0	1,250	3,574	210	3,112	1,355	1,965	5,117	1,878	2,838	1,270	850	24,943
CHP	19	13	0	0	123	120	185	42	750	89	63	151	102	116	254	188	20	2,234
Hydro	704	0	178	371	0	124	0	11	133	0	0	0	16	0	0	0	0	1,536
Interconnector	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,308	0	0	3,308
Medium Unit Coal	0	0	0	0	2,304	0	0	5,843	994	2,947	2,955	0	2,004	0	0	0	0	17,047
Nuclear AGR	0	0	0	0	0	1,200	0	0	1,155	0	0	0	0	0	0	0	0	2,355
Nuclear PWR	0	0	0	0	0	0	0	0	0	0	0	2,406	0	0	0	0	1,261	3,667
OCGT	0	0	0	0	0	0	0	67	0	0	0	0	0	0	0	145	140	352
Offshore Wind	10	0	0	0	0	0	94	3,600	6,000	5,000	0	3,000	1,608	1,750	1,000	0	0	22,062
Oil + AGT	24	0	0	10	0	21	6	185	203	64	98	302	171	243	79	160	128	1,695
Pumped Storage	300	0	0	440	0	0	0	0	2,004	0	0	0	0	0	0	0	0	2,744
Small Unit Coal	0	0	0	0	0	0	420	276	0	30	17	0	0	0	0	0	0	743
Onshore Wind	2,157	898	169	682	52	4,479	169	125	868	479	100	295	66	50	50	100	47	10,785
Gas	0	0	0	0	0	0	124	224	227	0	156	11	0	30	0	179	0	952
Microgen	0	0	0	0	0	0	0	0	0	0	0	0	0	71	0	0	0	71
Other	0	0	0	0	0	0	40	40	0	0	0	0	87	272	0	117	59	614
Supercritical coal	0	0	0	0	0	0	0	0	500	0	0	0	0	0	3,200	0	0	3,700
Waste	0	0	0	0	0	0	10	0	0	38	0	0	0	0	0	0	0	48
Overall Effective Generation	**3,484**	**2,435**	**347**	**1,768**	**2,479**	**6,241**	**2,609**	**14,296**	**13,339**	**11,759**	**4,755**	**8,162**	**9,170**	**4,411**	**10,729**	**2,187**	**2,855**	**101,025**

A.1.2 Modified dispatch

Sum of 2020/21 Capacity (MW)		SYS Study Zone																	
Plant Type	**Load Factor**	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	**Total MW**
Biomass	85.0%	129	0	0	225	0	252	294	294	251	0	9	27	0	0	0	24	338	1,843
CCGT	66.0%	0	205	0	0	0	0	824	2,357	139	2,053	1,294	1,296	3,875	1,239	1,372	1,088	711	16,451
CHP	90.0%	17	12	0	0	111	108	166	37	675	80	57	136	92	104	229	169	18	2,011
Hydro	66.3%	467	0	118	246	0	82	0	7	88	0	0	0	11	0	0	0	0	1,018
Interconnector	80.9%	0	0	0	0	0	-300	0	0	0	0	0	0	0	0	2,977	0	0	2,677
Medium Unit Coal	15.7%	0	0	0	0	230	0	0	584	99	295	1,266	0	200	0	0	0	0	2,675
Nuclear AGR	80.0%	0	0	0	0	0	960	0	0	924	0	0	0	0	0	0	0	0	1,884
Nuclear PWR	85.0%	0	0	0	0	0	0	0	0	0	0	0	2,045	0	0	0	0	1,072	3,117
OCGT	22.1%	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	32	31	78
Offshore Wind	85.0%	9	0	0	0	0	0	80	3,060	5,100	4,250	0	2,550	1,367	1,488	850	0	0	18,753
Oil + AGT	26.7%	6	0	0	3	0	6	2	49	54	17	26	80	46	65	21	43	34	452
Pumped Storage	25.6%	-300	0	0	0	0	0	0	0	1,002	0	0	0	0	0	0	0	0	702
Small Unit Coal	7.8%	0	0	0	0	0	0	33	22	0	2	1	0	0	0	0	0	0	58
Onshore Wind	75.0%	1,618	673	127	511	39	3,359	127	94	651	359	75	221	50	38	38	75	35	8,089
Gas	66.0%	0	0	0	0	0	0	82	148	150	0	103	8	0	20	0	118	0	628
Microgen	95.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68
Other	35.0%	0	0	0	0	0	0	14	14	0	0	0	0	30	95	0	41	21	215
Supercritical coal	40.0%	0	0	0	0	0	0	0	0	200	0	0	0	0	0	1,280	0	0	1,480
Waste	73.0%	0	0	0	0	0	0	7	0	0	28	0	0	0	0	0	0	0	35
Overall Effective Generation		**2,246**	**891**	**245**	**985**	**380**	**4,767**	**1,629**	**6,681**	**9,333**	**7,084**	**2,831**	**6,363**	**5,670**	**3,116**	**6,766**	**1,590**	**2,259**	**62,833**

A.1.3 Boundary flow of original dispatch

Boundary			**Dispatch on average marginal cost (MW)**									
No	**Name**	**Limit (MW)**	**Export (MW)**					**Import (MW)**				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	2,496	548	1,947	547	0	59,738	61,685	-1,947	547	0
2	North South SHETL	2,900	4,186	1,042	3,144	244	0	58,047	61,191	-3,144	244	0
3	Sloy Export	460	245	72	173	-	287	61,988	62,161	-173	-	287
4	SHETL-SPT Boundary	3,000	5,636	1,731	3,905	905	0	56,597	60,502	-3,905	905	0
5	North South SPT	3,570	6,016	3,066	2,950	-	620	56,217	59,167	-2,950	-	620
6	SPT-NGET Boundary	3,250	10,783	6,239	4,544	1,294	0	51,450	55,994	-4,544	1,294	0
7	Upper North-North	3,350	12,382	10,082	2,300	-	1,050	49,851	52,151	-2,300	-	1,050
8	North to Midlands	6,700	28,365	23,914	4,451	-	2,249	33,868	38,319	-4,451	-	2,249
9	Midlands to South	6,100	36,909	31,827	5,083	-	1,017	25,324	30,406	-5,083	-	1,017
10	South Coast	3,180	3,408	6,815	-3,406	226	0	58,825	55,418	3,406	226	0
11	North East & Yorkshire	6,670	19,033	16,199	2,833	-	3,837	43,200	46,034	-2,833	-	3,837
12	South & South West	3,670	8,578	12,396	-3,818	148	0	53,655	49,837	3,818	148	0
13	South West	2,840	2,069	2,928	-859	-	1,981	60,164	59,305	859	-	1,981
14	London	7,730	3,116	10,075	-6,959	-	771	59,117	52,158	6,959	-	771
15	Thames Estuary	4,800	7,266	1,968	5,298	498	0	54,967	60,265	-5,298	498	0
16	North East, Trent & Yorkshire	12,270	26,116	16,797	9,319	-	2,951	36,117	45,436	-9,319	-	2,951
17	West Midlands	4,940	1,461	7,315	-5,854	914	0	60,772	54,918	5,854	914	0

A.1.4 Boundary flow of modified dispatch

Boundary No	Name	Limit (MW)	Modified Dispatch (MW) Export (MW) Generation	Demand	Flow	Excess	Margin	Import (MW) Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	2,246	848	1,397	-	3	60,588	61,985	-1,397	-	3
2	North South SHETL	2,900	3,136	1,342	1,794	-	1,106	59,697	61,491	-1,794	-	1,106
3	Sloy Export	460	245	72	173	-	287	62,588	62,761	-173	-	287
4	SHETL-SPT Boundary	3,000	4,366	2,031	2,335	-	665	58,467	60,802	-2,335	-	665
5	North South SPT	3,570	4,746	3,366	1,380	-	2,190	58,087	59,467	-1,380	-	2,190
6	SPT-NGET Boundary	3,250	9,513	6,839	2,674	-	576	53,320	55,994	-2,674	-	576
7	Upper North-North	3,350	11,142	10,682	460	-	2,890	51,691	52,151	-460	-	2,890
8	North to Midlands	6,700	27,155	24,514	2,641	-	4,059	35,678	38,319	-2,641	-	4,059
9	Midlands to South	6,100	37,069	32,427	4,643	-	1,457	25,764	30,406	-4,643	-	1,457
10	South Coast	3,180	3,848	6,815	-2,966	-	214	58,985	56,018	2,966	-	214
11	North East & Yorkshire	6,670	17,823	16,799	1,023	-	5,647	45,010	46,034	-1,023	-	5,647
12	South & South West	3,670	9,518	12,396	-2,878	-	792	53,315	50,437	2,878	-	792
13	South West	2,840	2,259	2,928	-669	-	2,171	60,574	59,905	669	-	2,171
14	London	7,730	3,116	10,075	-6,959	-	771	59,717	52,758	6,959	-	771
15	Thames Estuary	4,800	6,766	1,968	4,798	-	2	56,067	60,865	-4,798	-	2
16	North East, Trent & Yorkshire	12,270	24,906	17,397	7,509	-	4,761	37,927	45,436	-7,509	-	4,761
17	West Midlands	4,940	2,831	7,315	-4,484	-	456	60,002	55,518	4,484	-	456

A.2 High Wind, Peak Demand – Medium Scenario

A.2.1 Available capacity

Sum of 2020/21 Capacity (MW)	SYS Study Zone																	
Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	320	0	0	315	0	397	500	500	295	0	11	31	0	0	0	28	500	2,898
CCGT	0	1,524	0	0	0	0	250	3,574	210	3,112	1,355	1,965	5,117	1,408	2,838	1,270	850	23,473
CHP	19	13	0	0	123	120	185	42	750	89	63	151	102	116	254	188	20	2,234
Hydro	704	0	178	371	0	124	0	11	133	0	0	0	16	0	0	0	0	1,536
Interconnector	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,308	0	0	3,308
Medium Unit Coal	0	0	0	0	2,304	0	0	6,233	994	2,947	2,460	0	2,004	0	0	0	0	16,942
Nuclear AGR	0	0	0	0	0	1,200	0	0	1,155	0	0	0	0	0	0	0	0	2,355
Nuclear PWR	0	0	0	0	0	0	0	0	0	0	0	2,406	0	0	0	0	1,261	3,667
OCGT	0	0	0	0	0	0	0	67	0	0	0	0	0	0	0	145	140	352
Offshore Wind	10	0	0	0	0	0	94	7,700	6,000	5,000	0	3,000	1,608	1,800	1,000	0	0	26,212
Oil + AGT	24	0	0	10	0	21	6	185	203	64	98	302	171	243	79	160	128	1,695
Pumped Storage	300	0	0	440	0	0	0	0	2,004	0	0	0	0	0	0	0	0	2,744
Small Unit Coal	0	0	0	0	0	0	420	276	0	30	17	0	0	0	0	0	0	743
Onshore Wind	2,157	898	169	682	52	4,479	219	425	868	479	250	295	316	200	200	250	297	12,235
Gas	0	0	0	0	0	0	124	224	227	0	156	11	0	30	0	179	0	952
Microgen	0	0	0	0	0	0	0	0	0	0	0	0	0	71	0	0	0	71
Other	0	0	0	0	0	0	40	40	0	0	0	0	87	272	0	117	59	614
Supercritical coal	0	0	0	0	0	0	0	0	500	0	0	0	0	0	3,200	0	0	3,700
Waste	0	0	0	0	0	0	10	0	0	38	0	0	0	0	0	0	0	48
Overall Effective Generation	**3,534**	**2,435**	**347**	**1,818**	**2,479**	**6,341**	**1,849**	**19,276**	**13,339**	**11,759**	**4,410**	**8,162**	**9,420**	**4,141**	**10,879**	**2,337**	**3,255**	**105,780**

A.2.2 Modified dispatch

Sum of 2020/21 Capacity (MW)		SYS Study Zone																	
Plant Type	Load Factor	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	85.0%	122	0	0	268	0	362	455	455	276	0	9	27	0	0	0	24	465	2,463
CCGT	34.0%	0	213	0	0	0	0	76	87	64	946	412	598	2,406	428	863	1,186	708	7,988
CHP	90.0%	17	12	0	0	111	108	166	37	675	80	57	136	92	104	229	169	18	2,011
Hydro	64.6%	455	0	115	239	0	80	0	7	86	0	0	0	10	0	0	0	0	992
Interconnector	80.9%	0	0	0	0	0	-300	0	0	0	0	0	0	0	0	2,977	0	0	2,677
Medium Unit Coal	39.5%	0	0	0	0	143	0	0	1,917	385	143	2,124	0	1,977	0	0	0	0	6,688
Nuclear AGR	80.0%	0	0	0	0	0	960	0	0	924	0	0	0	0	0	0	0	0	1,884
Nuclear PWR	85.0%	0	0	0	0	0	0	0	0	0	0	0	2,045	0	0	0	0	1,072	3,117
OCGT	3.7%	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	5	5	13
Offshore Wind	85.0%	9	0	0	0	0	0	80	6,545	5,100	4,250	0	2,550	1,367	1,530	850	0	0	22,280
Oil + AGT	8.0%	2	0	0	1	0	2	1	15	16	5	8	24	14	19	6	13	10	136
Pumped Storage	25.6%	-300	0	0	0	0	0	0	0	1,002	0	0	0	0	0	0	0	0	702
Small Unit Coal	2.4%	0	0	0	0	0	0	10	7	0	1	0	0	0	0	0	0	0	18
Onshore Wind	75.0%	1,618	673	127	511	39	3,359	164	319	651	359	188	221	237	150	150	188	222	9,176
Gas	30.4%	0	0	0	0	0	0	38	68	69	0	47	3	0	9	0	54	0	290
Microgen	95.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68
Other	35.0%	0	0	0	0	0	0	14	14	0	0	0	0	30	95	0	41	21	215
Supercritical coal	40.0%	0	0	0	0	0	0	0	0	200	0	0	0	0	0	1,280	0	0	1,480
Waste	73.0%	0	0	0	0	0	0	7	0	0	28	0	0	0	0	0	0	0	35
Overall Effective Generation		**2,222**	**899**	**242**	**1,019**	**293**	**4,871**	**1,011**	**9,472**	**9,448**	**5,812**	**2,845**	**5,604**	**6,133**	**2,404**	**6,355**	**1,680**	**2,522**	**62,833**

A.2.3 Boundary flow of original dispatch

Boundary No	Name	Limit (MW)	Dispatch on average marginal cost (MW) Export (MW) Generation	Demand	Flow	Excess	Margin	Import (MW) Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	2,522	548	1,973	573	0	59,712	61,685	-1,973	573	0
2	North South SHETL	2,900	3,670	1,042	2,628	-	272	58,563	61,191	-2,628	-	272
3	Sloy Export	460	242	72	170	-	290	61,992	62,161	-170	-	290
4	SHETL-SPT Boundary	3,000	5,152	1,731	3,421	421	0	57,082	60,502	-3,420	420	0
5	North South SPT	3,570	6,194	3,066	3,128	-	442	56,039	59,167	-3,128	-	442
6	SPT-NGET Boundary	3,250	11,041	6,239	4,802	1,552	0	51,193	55,994	-4,801	1,551	0
7	Upper North-North	3,350	12,022	10,082	1,940	-	1,410	50,211	52,151	-1,939	-	1,411
8	North to Midlands	6,700	32,388	23,914	8,474	1,774	0	29,846	38,319	-8,473	1,773	0
9	Midlands to South	6,100	40,875	31,827	9,048	2,948	0	21,359	30,406	-9,047	2,947	0
10	South Coast	3,180	2,912	6,815	-3,902	722	0	59,321	55,418	3,903	723	0
11	North East & Yorkshire	6,670	22,965	16,199	6,765	95	0	39,269	46,034	-6,765	95	0
12	South & South West	3,670	6,995	12,396	-5,401	1,731	0	55,238	49,837	5,401	1,731	0
13	South West	2,840	2,032	2,928	-896	-	1,944	60,202	59,305	896	-	1,944
14	London	7,730	2,404	10,075	-7,671	-	59	59,829	52,158	7,672	-	58
15	Thames Estuary	4,800	6,355	1,968	4,387	-	413	55,878	60,265	-4,387	-	413
16	North East, Trent & Yorkshire	12,270	29,776	16,797	12,980	710	0	32,457	45,436	-12,979	709	0
17	West Midlands	4,940	1,675	7,315	-5,640	700	0	60,558	54,918	5,640	700	0

A.2.4 Boundary flow of modified dispatch

Boundary			Modified Dispatch (MW)									
No	Name	Limit (MW)	Export (MW)					Import (MW)				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	2,222	848	1,373	-	27	60,612	61,985	-1,373	-	27
2	North South SHETL	2,900	3,120	1,342	1,778	-	1,122	59,713	61,491	-1,778	-	1,122
3	Sloy Export	460	242	72	170	-	290	62,592	62,761	-170	-	290
4	SHETL-SPT Boundary	3,000	4,382	2,031	2,351	-	649	58,452	60,802	-2,350	-	650
5	North South SPT	3,570	4,674	3,366	1,308	-	2,262	58,159	59,467	-1,308	-	2,262
6	SPT-NGET Boundary	3,250	9,546	6,839	2,707	-	543	53,288	55,994	-2,706	-	544
7	Upper North-North	3,350	10,557	10,682	-125	-	3,225	52,276	52,151	126	-	3,224
8	North to Midlands	6,700	29,478	24,514	4,964	-	1,736	33,356	38,319	-4,963	-	1,737
9	Midlands to South	6,100	38,135	32,427	5,708	-	392	24,699	30,406	-5,707	-	393
10	South Coast	3,180	4,202	6,815	-2,612	-	568	58,631	56,018	2,613	-	567
11	North East & Yorkshire	6,670	20,030	16,799	3,230	-	3,440	42,804	46,034	-3,230	-	3,440
12	South & South West	3,670	10,335	12,396	-2,061	-	1,609	52,498	50,437	2,061	-	1,609
13	South West	2,840	2,522	2,928	-406	-	2,434	60,312	59,905	406	-	2,434
14	London	7,730	2,404	10,075	-7,671	-	59	60,429	52,758	7,672	-	58
15	Thames Estuary	4,800	6,355	1,968	4,387	-	413	56,478	60,865	-4,387	-	413
16	North East, Trent & Yorkshire	12,270	25,841	17,397	8,445	-	3,825	36,992	45,436	-8,444	-	3,826
17	West Midlands	4,940	2,845	7,315	-4,470	-	470	59,988	55,518	4,470	-	470

A.3 High Wind, Peak Demand – High Scenario

A.3.1 Available capacity

Sum of 2020/21 Capacity (MW)	SYS Study Zone																	
Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	320	0	0	315	0	397	600	600	295	0	11	31	0	0	0	28	700	3,298
CCGT	0	1,524	0	0	0	0	50	3,104	210	3,112	1,355	1,965	5,117	1,608	2,838	1,270	850	23,003
CHP	19	13	0	0	123	120	185	42	750	89	63	151	102	116	254	188	20	2,234
Hydro	704	0	178	371	0	124	0	11	133	0	0	0	16	0	0	0	0	1,536
Interconnector	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,308	0	0	3,308
Medium Unit Coal	0	0	0	0	2,304	0	0	6,233	497	2,947	2,460	0	1,218	0	0	0	0	15,659
Nuclear AGR	0	0	0	0	0	1,200	0	0	1,155	0	0	0	0	0	0	0	0	2,355
Nuclear PWR	0	0	0	0	0	0	0	0	0	0	0	2,406	0	0	0	0	1,261	3,667
OCGT	0	0	0	0	0	0	0	67	0	0	0	0	0	0	0	145	140	352
Offshore Wind	10	0	0	0	0	0	94	15,200	6,000	5,000	0	3,000	1,608	1,800	1,000	0	0	33,712
Oil + AGT	24	0	0	10	0	21	6	185	203	64	98	302	171	243	79	160	128	1,695
Pumped Storage	300	0	0	440	0	0	0	0	2,004	0	0	0	0	0	0	0	0	2,744
Small Unit Coal	0	0	0	0	0	0	420	276	0	30	17	0	0	0	0	0	0	743
Onshore Wind	2,157	898	169	682	52	4,479	419	425	868	479	400	445	466	400	500	500	247	13,585
Gas	0	0	0	0	0	0	124	224	227	0	156	11	0	30	0	179	0	952
Microgen	0	0	0	0	0	0	0	0	0	0	0	0	0	71	0	0	0	71
Other	0	0	0	0	0	0	40	40	0	0	0	0	87	272	0	117	59	614
Supercritical coal	0	0	0	0	0	0	0	0	500	0	0	0	0	0	3,200	0	0	3,700
Waste	0	0	0	0	0	0	10	0	0	38	0	0	0	0	0	0	0	48
Overall Effective Generation	**3,534**	**2,435**	**347**	**1,818**	**2,479**	**6,341**	**1,949**	**26,406**	**12,842**	**11,759**	**4,560**	**8,312**	**8,784**	**4,541**	**11,179**	**2,587**	**3,405**	**113,277**

A.3.2 Modified dispatch

Sum of 2020/21 Capacity (MW)		SYS Study Zone																	
Plant Type	Load Factor	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	85.0%	172	0	0	268	0	337	540	540	251	0	9	27	0	0	0	24	635	2,803
CCGT	17.2%	0	39	0	0	0	0	4	43	15	33	127	141	1,327	265	153	1,091	711	3,949
CHP	90.0%	17	12	0	0	111	108	166	37	675	80	57	136	92	104	229	169	18	2,011
Hydro	57.2%	403	0	102	212	0	71	0	6	76	0	0	0	9	0	0	0	0	878
Interconnector	80.2%	0	0	0	0	0	-300	0	0	0	0	0	0	0	0	2,952	0	0	2,652
Medium Unit Coal	22.9%	0	0	0	0	38	0	0	38	59	44	2,248	0	1,161	0	0	0	0	3,589
Nuclear AGR	80.0%	0	0	0	0	0	960	0	0	924	0	0	0	0	0	0	0	0	1,884
Nuclear PWR	85.0%	0	0	0	0	0	0	0	0	0	0	0	2,045	0	0	0	0	1,072	3,117
OCGT	5.9%	0	0	0	0	0	0	0	4	0	0	0	0	0	0	0	9	8	21
Offshore Wind	85.0%	9	0	0	0	0	0	80	9,860	5,100	4,250	0	5,610	1,367	1,530	850	0	0	28,655
Oil + AGT	10.0%	2	0	0	1	0	2	1	19	20	6	10	30	17	24	8	16	13	169
Pumped Storage	15.7%	-300	0	0	0	0	0	0	0	731	0	0	0	0	0	0	0	0	431
Small Unit Coal	2.4%	0	0	0	0	0	0	10	7	0	1	0	0	0	0	0	0	0	18
Onshore Wind	75.0%	1,618	673	127	511	39	3,359	314	319	651	359	300	334	350	300	375	375	185	10,189
Gas	7.2%	0	0	0	0	0	0	9	16	16	0	11	1	0	2	0	13	0	68
Microgen	95.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68
Other	35.0%	0	0	0	0	0	0	14	14	0	0	0	0	30	95	0	41	21	215
Supercritical coal	40.0%	0	0	0	0	0	0	0	0	200	0	0	0	0	0	1,280	0	0	1,480
Waste	73.0%	0	0	0	0	0	0	7	0	0	28	0	0	0	0	0	0	0	35
Overall Effective Generation		**2,220**	**725**	**229**	**992**	**188**	**4,838**	**1,145**	**10,902**	**8,719**	**4,802**	**2,763**	**8,323**	**4,352**	**2,389**	**5,847**	**1,738**	**2,663**	**62,833**

A.3.3 Boundary flow of original dispatch

Boundary			Dispatch on average marginal cost (MW)									
No	Name	Limit (MW)	Export (MW)					Import (MW)				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	2,429	548	1,881	481	0	59,804	61,685	-1,881	481	0
2	North South SHETL	2,900	3,224	1,042	2,182	-	718	59,009	61,191	-2,182	-	718
3	Sloy Export	460	229	72	157	-	303	62,005	62,161	-157	-	303
4	SHETL-SPT Boundary	3,000	4,605	1,731	2,874	-	126	57,628	60,502	-2,874	-	126
5	North South SPT	3,570	5,493	3,066	2,427	-	1,143	56,740	59,167	-2,427	-	1,143
6	SPT-NGET Boundary	3,250	10,331	6,239	4,092	842	0	51,902	55,994	-4,092	842	0
7	Upper North-North	3,350	11,446	10,082	1,364	-	1,986	50,787	52,151	-1,364	-	1,986
8	North to Midlands	6,700	36,337	23,914	12,423	5,723	0	25,896	38,319	-12,423	5,723	0
9	Midlands to South	6,100	43,501	31,827	11,675	5,575	0	18,732	30,406	-11,675	5,575	0
10	South Coast	3,180	2,710	6,815	-4,105	925	0	59,523	55,418	4,105	925	0
11	North East & Yorkshire	6,670	27,518	16,199	11,318	4,648	0	34,715	46,034	-11,318	4,648	0
12	South & South West	3,670	5,332	12,396	-7,064	3,394	0	56,901	49,837	7,064	3,394	0
13	South West	2,840	1,973	2,928	-955	-	1,885	60,260	59,305	955	-	1,885
14	London	7,730	2,239	10,075	-7,836	106	0	59,994	52,158	7,836	106	0
15	Thames Estuary	4,800	5,897	1,968	3,929	-	871	56,336	60,265	-3,929	-	871
16	North East, Trent & Yorkshire	12,270	33,409	16,797	16,613	4,343	0	28,824	45,436	-16,612	4,342	0
17	West Midlands	4,940	1,273	7,315	-6,042	1,102	0	60,960	54,918	6,042	1,102	0

A.3.4 Boundary flow of modified dispatch

Boundary			Modified Dispatch (MW)									
No	Name	Limit (MW)	Export (MW)					Import (MW)				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	2,220	848	1,372	-	28	60,614	61,985	-1,371	-	29
2	North South SHETL	2,900	2,945	1,342	1,602	-	1,298	59,889	61,491	-1,602	-	1,298
3	Sloy Export	460	229	72	157	-	303	62,605	62,762	-157	-	303
4	SHETL-SPT Boundary	3,000	4,165	2,031	2,134	-	866	58,668	60,802	-2,134	-	866
5	North South SPT	3,570	4,353	3,366	987	-	2,583	58,480	59,467	-987	-	2,583
6	SPT-NGET Boundary	3,250	9,191	6,839	2,351	-	899	53,643	55,994	-2,351	-	899
7	Upper North-North	3,350	10,336	10,683	-347	-	3,003	52,498	52,151	347	-	3,003
8	North to Midlands	6,700	29,957	24,515	5,442	-	1,258	32,877	38,319	-5,442	-	1,258
9	Midlands to South	6,100	37,521	32,427	5,094	-	1,006	25,312	30,406	-5,094	-	1,006
10	South Coast	3,180	4,400	6,815	-2,415	-	765	58,433	56,019	2,415	-	765
11	North East & Yorkshire	6,670	21,237	16,800	4,438	-	2,232	41,596	46,034	-4,438	-	2,232
12	South & South West	3,670	8,752	12,396	-3,644	-	26	54,081	50,437	3,644	-	26
13	South West	2,840	2,663	2,928	-265	-	2,575	60,171	59,906	265	-	2,575
14	London	7,730	2,389	10,075	-7,686	-	44	60,444	52,758	7,686	-	44
15	Thames Estuary	4,800	5,847	1,968	3,879	-	921	56,986	60,865	-3,879	-	921
16	North East, Trent & Yorkshire	12,270	26,039	17,397	8,642	-	3,628	36,794	45,436	-8,642	-	3,628
17	West Midlands	4,940	2,763	7,315	-4,552	-	388	60,070	55,518	4,552	-	388

A.4 Low Wind, Peak Demand – Low Scenario

A.4.1 Available capacity

Sum of 2020/21 Capacity (MW)	SYS Study Zone																	
Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	270	0	0	265	0	297	310	310	295	0	11	31	0	0	0	28	350	2,168
CCGT	0	1,524	0	0	0	0	1,250	3,574	210	3,112	1,355	1,965	5,117	1,878	2,838	1,270	850	24,943
CHP	19	13	0	0	123	120	185	42	750	89	63	151	102	116	254	188	20	2,234
Hydro	704	0	178	371	0	124	0	11	133	0	0	0	16	0	0	0	0	1,536
Interconnector	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,308	0	0	3,308
Medium Unit Coal	0	0	0	0	2,304	0	0	5,843	994	2,947	2,955	0	2,004	0	0	0	0	17,047
Nuclear AGR	0	0	0	0	0	1,200	0	0	1,155	0	0	0	0	0	0	0	0	2,355
Nuclear PWR	0	0	0	0	0	0	0	0	0	0	0	2,406	0	0	0	0	1,261	3,667
OCGT	0	0	0	0	0	0	0	67	0	0	0	0	0	0	0	145	140	352
Offshore Wind	10	0	0	0	0	0	94	3,600	6,000	5,000	0	3,000	1,608	1,750	1,000	0	0	22,062
Oil + AGT	24	0	0	10	0	21	6	185	203	64	98	302	171	243	79	160	128	1,695
Pumped Storage	300	0	0	440	0	0	0	0	2,004	0	0	0	0	0	0	0	0	2,744
Small Unit Coal	0	0	0	0	0	0	420	276	0	30	17	0	0	0	0	0	0	743
Onshore Wind	2,157	898	169	682	52	4,479	169	125	868	479	100	295	66	50	50	100	47	10,785
Gas	0	0	0	0	0	0	124	224	227	0	156	11	0	30	0	179	0	952
Microgen	0	0	0	0	0	0	0	0	0	0	0	0	0	71	0	0	0	71
Other	0	0	0	0	0	0	40	40	0	0	0	0	87	272	0	117	59	614
Supercritical coal	0	0	0	0	0	0	0	0	500	0	0	0	0	0	3,200	0	0	3,700
Waste	0	0	0	0	0	0	10	0	0	38	0	0	0	0	0	0	0	48
Overall Effective Generation	**3,484**	**2,435**	**347**	**1,768**	**2,479**	**6,241**	**2,609**	**14,296**	**13,339**	**11,759**	**4,755**	**8,162**	**9,170**	**4,411**	**10,729**	**2,187**	**2,855**	**101,025**

A.4.2 Modified dispatch

Sum of 2020/21 Capacity (MW)		SYS Study Zone																	
Plant Type	Load Factor	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	85.0%	229	0	0	225	0	252	264	264	251	0	9	27	0	0	0	24	298	1,843
CCGT	84.5%	0	1,487	0	0	0	0	1,056	3,419	177	3,028	1,144	1,660	4,922	1,786	397	1,173	818	21,067
CHP	90.0%	17	12	0	0	111	108	166	37	675	80	57	136	92	104	229	169	18	2,011
Hydro	66.3%	467	0	118	246	0	82	0	7	88	0	0	0	11	0	0	0	0	1,018
Interconnector	90.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,977	0	0	2,977
Medium Unit Coal	85.0%	0	0	0	0	1,958	0	0	4,967	845	2,505	2,512	0	1,703	0	0	0	0	14,490
Nuclear AGR	80.0%	0	0	0	0	0	960	0	0	924	0	0	0	0	0	0	0	0	1,884
Nuclear PWR	85.0%	0	0	0	0	0	0	0	0	0	0	0	2,045	0	0	0	0	1,072	3,117
OCGT	22.1%	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	32	31	78
Offshore Wind	25.1%	3	0	0	0	0	0	24	905	1,509	1,257	0	754	404	440	251	0	0	5,547
Oil + AGT	26.7%	6	0	0	3	0	6	2	49	54	17	26	80	46	65	21	43	34	452
Pumped Storage	50.0%	150	0	0	220	0	0	0	0	1,002	0	0	0	0	0	0	0	0	1,372
Small Unit Coal	7.8%	0	0	0	0	0	0	33	22	0	2	1	0	0	0	0	0	0	58
Onshore Wind	17.3%	373	155	29	118	9	775	29	22	150	83	17	51	11	9	9	17	8	1,867
Gas	84.5%	0	0	0	0	0	0	105	189	192	0	132	10	0	26	0	151	0	804
Microgen	95.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68
Other	35.0%	0	0	0	0	0	0	14	14	0	0	0	0	30	95	0	41	21	215
Supercritical coal	90.0%	0	0	0	0	0	0	0	0	450	0	0	0	0	0	2,880	0	0	3,330
Waste	73.0%	0	0	0	0	0	0	7	0	0	28	0	0	0	0	0	0	0	35
Overall Effective Generation		**1,245**	**1,655**	**147**	**812**	**2,078**	**2,184**	**1,699**	**9,909**	**6,317**	**7,001**	**3,899**	**4,763**	**7,219**	**2,593**	**6,764**	**1,650**	**2,299**	**62,233**

A.4.3 Boundary flow of original dispatch

Boundary			Dispatch on average marginal cost (MW)									
No	Name	Limit (MW)	Export (MW)					Import (MW)				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	1,245	548	697	-	703	60,988	61,685	-697	-	703
2	North South SHETL	2,900	2,700	1,042	1,658	-	1,242	59,533	61,191	-1,657	-	1,243
3	Sloy Export	460	147	72	75	-	385	62,086	62,161	-75	-	385
4	SHETL-SPT Boundary	3,000	3,659	1,731	1,928	-	1,072	58,574	60,502	-1,928	-	1,072
5	North South SPT	3,570	5,737	3,066	2,671	-	899	56,496	59,167	-2,671	-	899
6	SPT-NGET Boundary	3,250	7,921	6,239	1,682	-	1,568	54,313	55,994	-1,681	-	1,569
7	Upper North-North	3,350	9,620	10,082	-462	-	2,888	52,613	52,151	463	-	2,887
8	North to Midlands	6,700	25,446	23,914	1,531	-	5,169	36,788	38,319	-1,531	-	5,169
9	Midlands to South	6,100	35,945	31,827	4,118	-	1,982	26,288	30,406	-4,118	-	1,982
10	South Coast	3,180	3,749	6,815	-3,066	-	114	58,484	55,418	3,066	-	114
11	North East & Yorkshire	6,670	19,129	16,199	2,930	-	3,740	43,104	46,034	-2,929	-	3,741
12	South & South West	3,670	10,368	12,396	-2,028	-	1,642	51,865	49,837	2,028	-	1,642
13	South West	2,840	2,199	2,928	-729	-	2,111	60,034	59,305	729	-	2,111
14	London	7,730	2,393	10,075	-7,683	-	47	59,840	52,158	7,683	-	47
15	Thames Estuary	4,800	8,764	1,968	6,796	1,996	0	53,469	60,265	-6,796	1,996	0
16	North East, Trent & Yorkshire	12,270	25,729	16,797	8,933	-	3,337	36,504	45,436	-8,932	-	3,338
17	West Midlands	4,940	3,899	7,315	-3,416	-	1,524	58,334	54,918	3,416	-	1,524

A.4.4 Boundary flow of modified dispatch

Boundary No	Boundary Name	Limit (MW)	Modified Dispatch (MW): Export (MW) Generation	Export Demand	Export Flow	Export Excess	Export Margin	Import (MW) Generation	Import Demand	Import Flow	Import Excess	Import Margin
1	North West Export	1,400	1,245	548	697	-	703	60,988	61,685	-697	-	703
2	North South SHETL	2,900	2,900	1,042	1,858	-	1,042	59,333	61,191	-1,857	-	1,043
3	Sloy Export	460	147	72	75	-	385	62,086	62,161	-75	-	385
4	SHETL-SPT Boundary	3,000	3,859	1,731	2,128	-	872	58,374	60,502	-2,128	-	872
5	North South SPT	3,570	5,937	3,066	2,871	-	699	56,296	59,167	-2,871	-	699
6	SPT-NGET Boundary	3,250	8,121	6,239	1,882	-	1,368	54,113	55,994	-1,881	-	1,369
7	Upper North-North	3,350	9,820	10,082	-262	-	3,088	52,413	52,151	263	-	3,087
8	North to Midlands	6,700	26,046	23,914	2,131	-	4,569	36,188	38,319	-2,131	-	4,569
9	Midlands to South	6,100	36,945	31,827	5,118	-	982	25,288	30,406	-5,118	-	982
10	South Coast	3,180	3,949	6,815	-2,866	-	314	58,284	55,418	2,866	-	314
11	North East & Yorkshire	6,670	19,729	16,199	3,530	-	3,140	42,504	46,034	-3,529	-	3,141
12	South & South West	3,670	11,168	12,396	-1,228	-	2,442	51,065	49,837	1,228	-	2,442
13	South West	2,840	2,299	2,928	-629	-	2,211	59,934	59,305	629	-	2,211
14	London	7,730	2,593	10,075	-7,483	-	247	59,640	52,158	7,483	-	247
15	Thames Estuary	4,800	6,764	1,968	4,796	-	4	55,469	60,265	-4,796	-	4
16	North East, Trent & Yorkshire	12,270	26,729	16,797	9,933	-	2,337	35,504	45,436	-9,932	-	2,338
17	West Midlands	4,940	3,899	7,315	-3,416	-	1,524	58,334	54,918	3,416	-	1,524

A.5 Low Wind, Peak Demand – Medium Scenario

A.5.1 Available capacity

Sum of 2020/21 Capacity (MW)	SYS Study Zone																	
Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	**Total MW**
Biomass	320	0	0	315	0	397	500	500	295	0	11	31	0	0	0	28	500	2,898
CCGT	0	1,524	0	0	0	0	250	3,574	210	3,112	1,355	1,965	5,117	1,408	2,838	1,270	850	23,473
CHP	19	13	0	0	123	120	185	42	750	89	63	151	102	116	254	188	20	2,234
Hydro	704	0	178	371	0	124	0	11	133	0	0	0	16	0	0	0	0	1,536
Interconnector	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,308	0	0	3,308
Medium Unit Coal	0	0	0	0	2,304	0	0	6,233	994	2,947	2,460	0	2,004	0	0	0	0	16,942
Nuclear AGR	0	0	0	0	0	1,200	0	0	1,155	0	0	0	0	0	0	0	0	2,355
Nuclear PWR	0	0	0	0	0	0	0	0	0	0	0	2,406	0	0	0	0	1,261	3,667
OCGT	0	0	0	0	0	0	0	67	0	0	0	0	0	0	0	145	140	352
Offshore Wind	10	0	0	0	0	0	94	7,700	6,000	5,000	0	3,000	1,608	1,800	1,000	0	0	26,212
Oil + AGT	24	0	0	10	0	21	6	185	203	64	98	302	171	243	79	160	128	1,695
Pumped Storage	300	0	0	440	0	0	0	0	2,004	0	0	0	0	0	0	0	0	2,744
Small Unit Coal	0	0	0	0	0	0	420	276	0	30	17	0	0	0	0	0	0	743
Onshore Wind	2,157	898	169	682	52	4,479	219	425	868	479	250	295	316	200	200	250	297	12,235
Gas	0	0	0	0	0	0	124	224	227	0	156	11	0	30	0	179	0	952
Microgen	0	0	0	0	0	0	0	0	0	0	0	0	0	71	0	0	0	71
Other	0	0	0	0	0	0	40	40	0	0	0	0	87	272	0	117	59	614
Supercritical coal	0	0	0	0	0	0	0	0	500	0	0	0	0	0	3,200	0	0	3,700
Waste	0	0	0	0	0	0	10	0	0	38	0	0	0	0	0	0	0	48
Overall Effective Generation	**3,534**	**2,435**	**347**	**1,818**	**2,479**	**6,341**	**1,849**	**19,276**	**13,339**	**11,759**	**4,410**	**8,162**	**9,420**	**4,141**	**10,879**	**2,337**	**3,255**	**105,780**

A.5.2 Modified dispatch

Sum of 2020/21 Capacity (MW)		SYS Study Zone																	
Plant Type	**Load Factor**	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	**Total MW**
Biomass	85.0%	272	0	0	268	0	337	425	425	251	0	9	27	0	0	0	24	425	2,463
CCGT	81.3%	0	1,440	0	0	0	0	203	2,907	171	2,931	1,102	1,598	4,962	1,395	458	1,133	791	19,092
CHP	90.0%	17	12	0	0	111	108	166	37	675	80	57	136	92	104	229	169	18	2,011
Hydro	64.6%	455	0	115	239	0	80	0	7	86	0	0	0	10	0	0	0	0	992
Interconnector	90.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,977	0	0	2,977
Medium Unit Coal	85.0%	0	0	0	0	1,958	0	0	5,298	845	2,505	2,091	0	1,703	0	0	0	0	14,401
Nuclear AGR	80.0%	0	0	0	0	0	960	0	0	924	0	0	0	0	0	0	0	0	1,884
Nuclear PWR	85.0%	0	0	0	0	0	0	0	0	0	0	0	2,045	0	0	0	0	1,072	3,117
OCGT	37.1%	0	0	0	0	0	0	0	25	0	0	0	0	0	0	0	54	52	130
Offshore Wind	25.6%	3	0	0	0	0	0	24	1,972	1,537	1,281	0	768	412	461	256	0	0	6,714
Oil + AGT	8.0%	2	0	0	1	0	2	1	15	16	5	8	24	14	19	6	13	10	136
Pumped Storage	50.0%	150	0	0	220	0	0	0	0	1,002	0	0	0	0	0	0	0	0	1,372
Small Unit Coal	54.2%	0	0	0	0	0	0	228	150	0	16	9	0	0	0	0	0	0	403
Onshore Wind	17.3%	373	155	29	118	9	775	38	74	150	83	43	51	55	35	35	43	51	2,118
Gas	81.3%	0	0	0	0	0	0	101	182	185	0	127	9	0	25	0	146	0	775
Microgen	95.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68
Other	35.0%	0	0	0	0	0	0	14	14	0	0	0	0	30	95	0	41	21	215
Supercritical coal	90.0%	0	0	0	0	0	0	0	0	450	0	0	0	0	0	2,880	0	0	3,330
Waste	73.0%	0	0	0	0	0	0	7	0	0	28	0	0	0	0	0	0	0	35
Overall Effective Generation		**1,271**	**1,607**	**144**	**846**	**2,078**	**2,263**	**1,207**	**11,106**	**6,291**	**6,929**	**3,446**	**4,659**	**7,278**	**2,203**	**6,841**	**1,623**	**2,441**	**62,233**

A.5.3 Boundary flow of original dispatch

Boundary No	Boundary Name	Limit (MW)	Dispatch on average marginal cost (MW): Export (MW) Generation	Export Demand	Export Flow	Export Excess	Export Margin	Import (MW) Generation	Import Demand	Import Flow	Import Excess	Import Margin
1	North West Export	1,400	1,271	548	723	-	677	60,962	61,685	-723	-	677
2	North South SHETL	2,900	2,678	1,042	1,636	-	1,264	59,555	61,191	-1,636	-	1,264
3	Sloy Export	460	144	72	72	-	388	62,089	62,161	-72	-	388
4	SHETL-SPT Boundary	3,000	3,669	1,731	1,938	-	1,062	58,565	60,502	-1,937	-	1,063
5	North South SPT	3,570	5,747	3,066	2,681	-	889	56,487	59,167	-2,681	-	889
6	SPT-NGET Boundary	3,250	8,009	6,239	1,771	-	1,479	54,224	55,994	-1,770	-	1,480
7	Upper North-North	3,350	9,217	10,082	-866	-	2,484	53,016	52,151	866	-	2,484
8	North to Midlands	6,700	26,614	23,914	2,700	-	4,000	35,619	38,319	-2,699	-	4,001
9	Midlands to South	6,100	36,589	31,827	4,763	-	1,337	25,644	30,406	-4,762	-	1,338
10	South Coast	3,180	3,863	6,815	-2,952	-	228	58,370	55,418	2,952	-	228
11	North East & Yorkshire	6,670	20,323	16,199	4,123	-	2,547	41,911	46,034	-4,123	-	2,547
12	South & South West	3,670	10,341	12,396	-2,055	-	1,615	51,892	49,837	2,055	-	1,615
13	South West	2,840	2,341	2,928	-587	-	2,253	59,893	59,305	588	-	2,252
14	London	7,730	1,953	10,075	-8,123	393	0	60,281	52,158	8,123	393	0
15	Thames Estuary	4,800	8,691	1,968	6,723	1,923	0	53,542	60,265	-6,723	1,923	0
16	North East, Trent & Yorkshire	12,270	26,852	16,797	10,055	-	2,215	35,382	45,436	-10,055	-	2,215
17	West Midlands	4,940	3,446	7,315	-3,868	-	1,072	58,787	54,918	3,869	-	1,071

A.5.4 Boundary flow of modified dispatch

Boundary			Modified Dispatch (MW)									
No	Name	Limit (MW)	Export (MW)					Import (MW)				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	1,271	548	723	-	677	60,962	61,685	-723	-	677
2	North South SHETL	2,900	2,878	1,042	1,836	-	1,064	59,355	61,191	-1,836	-	1,064
3	Sloy Export	460	144	72	72	-	388	62,089	62,161	-72	-	388
4	SHETL-SPT Boundary	3,000	3,869	1,731	2,138	-	862	58,365	60,502	-2,137	-	863
5	North South SPT	3,570	5,947	3,066	2,881	-	689	56,287	59,167	-2,881	-	689
6	SPT-NGET Boundary	3,250	8,209	6,239	1,971	-	1,279	54,024	55,994	-1,970	-	1,280
7	Upper North-North	3,350	9,417	10,082	-666	-	2,684	52,816	52,151	666	-	2,684
8	North to Midlands	6,700	26,814	23,914	2,900	-	3,800	35,419	38,319	-2,899	-	3,801
9	Midlands to South	6,100	37,189	31,827	5,363	-	737	25,044	30,406	-5,362	-	738
10	South Coast	3,180	4,063	6,815	-2,752	-	428	58,170	55,418	2,752	-	428
11	North East & Yorkshire	6,670	20,523	16,199	4,323	-	2,347	41,711	46,034	-4,323	-	2,347
12	South & South West	3,670	11,341	12,396	-1,055	-	2,615	50,892	49,837	1,055	-	2,615
13	South West	2,840	2,441	2,928	-487	-	2,353	59,793	59,305	488	-	2,352
14	London	7,730	2,203	10,075	-7,873	143	0	60,031	52,158	7,873	143	0
15	Thames Estuary	4,800	6,841	1,968	4,873	73	0	55,392	60,265	-4,873	73	0
16	North East, Trent & Yorkshire	12,270	27,452	16,797	10,655	-	1,615	34,782	45,436	-10,655	-	1,615
17	West Midlands	4,940	3,446	7,315	-3,868	-	1,072	58,787	54,918	3,869	-	1,071

A.6 Low Wind, Peak Demand – High Scenario

A.6.1 Available capacity

Sum of 2020/21 Capacity (MW)	SYS Study Zone																	
Plant Type	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	320	0	0	315	0	397	600	600	295	0	11	31	0	0	0	28	700	3,298
CCGT	0	1,524	0	0	0	0	50	3,104	210	3,112	1,355	1,965	5,117	1,608	2,838	1,270	850	23,003
CHP	19	13	0	0	123	120	185	42	750	89	63	151	102	116	254	188	20	2,234
Hydro	704	0	178	371	0	124	0	11	133	0	0	0	16	0	0	0	0	1,536
Interconnector	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,308	0	0	3,308
Medium Unit Coal	0	0	0	0	2,304	0	0	6,233	497	2,947	2,460	0	1,218	0	0	0	0	15,659
Nuclear AGR	0	0	0	0	0	1,200	0	0	1,155	0	0	0	0	0	0	0	0	2,355
Nuclear PWR	0	0	0	0	0	0	0	0	0	0	0	2,406	0	0	0	0	1,261	3,667
OCGT	0	0	0	0	0	0	0	67	0	0	0	0	0	0	0	145	140	352
Offshore Wind	10	0	0	0	0	0	94	15,200	6,000	5,000	0	3,000	1,608	1,800	1,000	0	0	33,712
Oil + AGT	24	0	0	10	0	21	6	185	203	64	98	302	171	243	79	160	128	1,695
Pumped Storage	300	0	0	440	0	0	0	0	2,004	0	0	0	0	0	0	0	0	2,744
Small Unit Coal	0	0	0	0	0	0	420	276	0	30	17	0	0	0	0	0	0	743
Onshore Wind	2,157	898	169	682	52	4,479	419	425	868	479	400	445	466	400	500	500	247	13,585
Gas	0	0	0	0	0	0	124	224	227	0	156	11	0	30	0	179	0	952
Microgen	0	0	0	0	0	0	0	0	0	0	0	0	0	71	0	0	0	71
Other	0	0	0	0	0	0	40	40	0	0	0	0	87	272	0	117	59	614
Supercritical coal	0	0	0	0	0	0	0	0	500	0	0	0	0	0	3,200	0	0	3,700
Waste	0	0	0	0	0	0	10	0	0	38	0	0	0	0	0	0	0	48
Overall Effective Generation	**3,534**	**2,435**	**347**	**1,818**	**2,479**	**6,341**	**1,949**	**26,406**	**12,842**	**11,759**	**4,560**	**8,312**	**8,784**	**4,541**	**11,179**	**2,587**	**3,405**	**113,277**

A.6.2 Modified dispatch

Sum of 2020/21 Capacity (MW)		SYS Study Zone																	
Plant Type	Load Factor	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	Z11	Z12	Z13	Z14	Z15	Z16	Z17	Total MW
Biomass	85.0%	272	0	0	268	0	337	510	510	251	0	9	27	0	0	0	24	595	2,803
CCGT	79.7%	0	1,415	0	0	0	0	40	2,475	167	2,782	1,080	1,567	4,980	1,582	363	1,113	778	18,343
CHP	90.0%	17	12	0	0	111	108	166	37	675	80	57	136	92	104	229	169	18	2,011
Hydro	57.2%	403	0	102	212	0	71	0	6	76	0	0	0	9	0	0	0	0	878
Interconnector	89.2%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,952	0	0	2,952
Medium Unit Coal	85.0%	0	0	0	0	1,958	0	0	5,298	422	2,505	2,091	0	1,035	0	0	0	0	13,310
Nuclear AGR	80.0%	0	0	0	0	0	960	0	0	924	0	0	0	0	0	0	0	0	1,884
Nuclear PWR	85.0%	0	0	0	0	0	0	0	0	0	0	0	2,045	0	0	0	0	1,072	3,117
OCGT	5.9%	0	0	0	0	0	0	0	4	0	0	0	0	0	0	0	9	8	21
Offshore Wind	25.8%	3	0	0	0	0	0	24	3,916	1,546	1,288	0	773	414	464	258	0	0	8,686
Oil + AGT	10.0%	2	0	0	1	0	2	1	19	20	6	10	30	17	24	8	16	13	169
Pumped Storage	50.0%	150	0	0	220	0	0	0	0	1,002	0	0	0	0	0	0	0	0	1,372
Small Unit Coal	2.4%	0	0	0	0	0	0	10	7	0	1	0	0	0	0	0	0	0	18
Onshore Wind	17.2%	371	154	29	117	9	770	72	73	149	82	69	76	80	69	86	86	42	2,335
Gas	79.7%	0	0	0	0	0	0	99	179	181	0	124	9	0	24	0	143	0	759
Microgen	95.0%	0	0	0	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68
Other	35.0%	0	0	0	0	0	0	14	14	0	0	0	0	30	95	0	41	21	215
Supercritical coal	88.0%	0	0	0	0	0	0	0	0	440	0	0	0	0	0	2,816	0	0	3,256
Waste	73.0%	0	0	0	0	0	0	7	0	0	28	0	0	0	0	0	0	0	35
Overall Effective Generation		**1,217**	**1,582**	**131**	**818**	**2,078**	**2,248**	**944**	**12,538**	**5,854**	**6,772**	**3,441**	**4,663**	**6,658**	**2,431**	**6,711**	**1,600**	**2,547**	**62,233**

A.6.3 Boundary flow of original dispatch

Boundary			Dispatch on average marginal cost (MW)									
No	Name	Limit (MW)	Export (MW)					Import (MW)				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	1,217	548	669	-	731	61,016	61,685	-668	-	732
2	North South SHETL	2,900	2,599	1,042	1,556	-	1,344	59,635	61,191	-1,556	-	1,344
3	Sloy Export	460	131	72	59	-	401	62,103	62,161	-59	-	401
4	SHETL-SPT Boundary	3,000	3,547	1,731	1,816	-	1,184	58,686	60,502	-1,816	-	1,184
5	North South SPT	3,570	5,625	3,066	2,560	-	1,010	56,608	59,167	-2,559	-	1,011
6	SPT-NGET Boundary	3,250	7,874	6,239	1,635	-	1,615	54,359	55,994	-1,635	-	1,615
7	Upper North-North	3,350	8,818	10,082	-1,265	-	2,085	53,416	52,151	1,265	-	2,085
8	North to Midlands	6,700	27,210	23,914	3,295	-	3,405	35,024	38,319	-3,295	-	3,405
9	Midlands to South	6,100	37,123	31,827	5,296	-	804	25,111	30,406	-5,296	-	804
10	South Coast	3,180	3,947	6,815	-2,868	-	312	58,286	55,418	2,868	-	312
11	North East & Yorkshire	6,670	21,356	16,199	5,156	-	1,514	40,878	46,034	-5,156	-	1,514
12	South & South West	3,670	9,705	12,396	-2,691	-	979	52,528	49,837	2,691	-	979
13	South West	2,840	2,447	2,928	-481	-	2,359	59,786	59,305	481	-	2,359
14	London	7,730	2,131	10,075	-7,945	215	0	60,102	52,158	7,945	215	0
15	Thames Estuary	4,800	8,611	1,968	6,643	1,843	0	53,622	60,265	-6,643	1,843	0
16	North East, Trent & Yorkshire	12,270	27,828	16,797	11,031	-	1,239	34,406	45,436	-11,031	-	1,239
17	West Midlands	4,940	3,441	7,315	-3,874	-	1,066	58,792	54,918	3,874	-	1,066

A.6.4 Boundary flow of modified dispatch

Boundary			Modified Dispatch (MW)									
No	Name	Limit (MW)	Export (MW)					Import (MW)				
			Generation	Demand	Flow	Excess	Margin	Generation	Demand	Flow	Excess	Margin
1	North West Export	1,400	1,217	548	669	-	731	61,016	61,685	-668	-	732
2	North South SHETL	2,900	2,799	1,042	1,756	-	1,144	59,435	61,191	-1,756	-	1,144
3	Sloy Export	460	131	72	59	-	401	62,103	62,161	-59	-	401
4	SHETL-SPT Boundary	3,000	3,747	1,731	2,016	-	984	58,486	60,502	-2,016	-	984
5	North South SPT	3,570	5,825	3,066	2,760	-	810	56,408	59,167	-2,759	-	811
6	SPT-NGET Boundary	3,250	8,074	6,239	1,835	-	1,415	54,159	55,994	-1,835	-	1,415
7	Upper North-North	3,350	9,018	10,082	-1,065	-	2,285	53,216	52,151	1,065	-	2,285
8	North to Midlands	6,700	27,410	23,914	3,495	-	3,205	34,824	38,319	-3,495	-	3,205
9	Midlands to South	6,100	37,623	31,827	5,796	-	304	24,611	30,406	-5,796	-	304
10	South Coast	3,180	4,147	6,815	-2,668	-	512	58,086	55,418	2,668	-	512
11	North East & Yorkshire	6,670	21,556	16,199	5,356	-	1,314	40,678	46,034	-5,356	-	1,314
12	South & South West	3,670	10,805	12,396	-1,591	-	2,079	51,428	49,837	1,591	-	2,079
13	South West	2,840	2,547	2,928	-381	-	2,459	59,686	59,305	381	-	2,459
14	London	7,730	2,431	10,075	-7,645	-	85	59,802	52,158	7,645	-	85
15	Thames Estuary	4,800	6,711	1,968	4,743	-	57	55,522	60,265	-4,743	-	57
16	North East, Trent & Yorkshire	12,270	28,328	16,797	11,531	-	739	33,906	45,436	-11,531	-	739
17	West Midlands	4,940	3,441	7,315	-3,874	-	1,066	58,792	54,918	3,874	-	1,066

Appendix B Offshore connection costings

B.1 Connection Cost Summary – Low Scenario

B.1.1 Installed capacity and connection summary

		Wash	North West	Thames	Wales	Dogger	Others	Total
Capacity	MW	8,000	6,000	2,750	1,500	3,600	212	**22,062**
Offshore distance	km	65	30	50	40	150	25	**360**
Onshore distance	km	43	10	5/ 50	6	60	20	**139**
Total		108	40	155	46	210	45	**604**
Connection		DC	AC	AC/ DC	AC	DC	AC	

B.1.2 Onshore connection with OHL

		Wash	North West	Thames	Wales	Dogger	Others	Total
Inter-array cabling		395	296	136	75	178	11	**1,089**
Offshore platform		440	360	161	95	202	14	**1,271**
Converter		1,785	0	510	0	765	0	**3,060**
Onshore grid interface		0	320	80	80	0	15	**495**
Submarine cable link	AC	0	478	132	169	0	6	**786**
	DC	371	0	82	0	363	0	**816**
Onshore grid connection circuit	AC	0	24	4	5	0	1	**34**
	DC	60	0	20	0	36	0	**116**
Total Connection Cost	**£'m**	**3,050**	**1,478**	**1,125**	**423**	**1,544**	**46**	**7,666**
Average cost per kW	**£/kW**	**381**	**246**	**409**	**282**	**429**	**216**	**347**

B.1.3 Onshore connection with UGC

		Wash	North West	Thames	Wales	Dogger	Others	Total
Inter-array cabling		395	296	136	75	178	11	**1,089**
Offshore platform		440	360	161	95	202	14	**1,271**
Converter		1,785	0	510	0	765	0	**3,060**
Onshore grid interface		0	320	80	80	0	15	**495**
Submarine cable link	AC	0	478	132	169	0	6	**786**
	DC	371	0	82	0	363	0	**816**
Onshore grid connection circuit	AC	0	240	20	36	0	6	**302**
	DC	312	0	105	0	189	0	**606**
Total Connection Cost	**£'m**	**3,303**	**1,694**	**1,226**	**454**	**1,697**	**51**	**8,425**
Average cost per kW	**£/kW**	**413**	**282**	**446**	**303**	**471**	**242**	**382**

B.2 Connection Cost Summary – Medium Scenario

B.2.1 Installed capacity and connection summary

		Wash	North West	Thames	Wales	Dogger	Others	Total
Capacity	MW	8,000	6,000	2,800	1,500	7,700	212	**26,212**
Offshore distance	km	65	30	50	40	150	25	**360**
Onshore distance	km	43	10	5/ 50	6	60	20	**139**
Total		108	40	155	46	210	45	**604**
Connection		DC	AC	AC/ DC	AC	DC	AC	

B.2.2 Onshore connection with OHL

		Wash	North West	Thames	Wales	Dogger	Others	Total
Inter-array cabling		395	296	138	75	380	11	**1,294**
Offshore platform		440	360	161	95	431	14	**1,500**
Converter		1,785	0	510	0	1,785	0	**4,080**
Onshore grid interface		0	320	80	80	0	15	**495**
Submarine cable link	AC	0	478	132	169	0	6	**786**
	DC	371	0	82	0	847	0	**1,300**
Onshore grid connection circuit	AC	0	24	4	5	0	1	**34**
	DC	60	0	20	0	84	0	**164**
Total Connection Cost	**£'m**	**3,050**	**1,478**	**1,127**	**423**	**3,527**	**46**	**9,651**
Average cost per kW	**£/kW**	**381**	**246**	**403**	**282**	**458**	**216**	**368**

B.2.3 Onshore connection with UGC

		Wash	North West	Thames	Wales	Dogger	Others	Total
Inter-array cabling		395	296	138	75	380	11	**1,294**
Offshore platform		440	360	161	95	431	14	**1,500**
Converter		1,785	0	510	0	1,785	0	**4,080**
Onshore grid interface		0	320	80	80	0	15	**495**
Submarine cable link	AC	0	478	132	169	0	6	**786**
	DC	371	0	82	0	847	0	**1,300**
Onshore grid connection circuit	AC	0	240	20	36	0	6	**302**
	DC	312	0	105	0	441	0	**858**
Total Connection Cost	**£'m**	**3,303**	**1,694**	**1,228**	**454**	**3,884**	**51**	**10,615**
Average cost per kW	**£/kW**	**413**	**282**	**439**	**303**	**504**	**242**	**405**

B.3 Connection Cost Summary – High Scenario

B.3.1 Installed capacity and connection summary

		Wash	North West	Thames	Wales	Dogger	Others	Total
Capacity	MW	8,000	6,000	2,800	1,500	15,200	212	**33,712**
Offshore distance	km	65	30	100	40	150/ 180	25	**260**
Onshore distance	km	43	10	5/ 50	6	60/ 65	20	**79**
Total		108	40	155	46	455	45	**849**
Connection		DC	AC	AC/ DC	AC	DC	AC	

B.3.2 Onshore connection with OHL

		Wash	North West	Thames	Wales	Dogger	Others	Total
Inter-array cabling		395	296	138	75	750	11	**1,664**
Offshore platform		440	360	161	95	844	14	**1,913**
Converter		1,785	0	510	0	3,315	0	**5,610**
Onshore grid interface		0	320	80	80	0	15	**495**
Submarine cable link	AC	0	478	132	169	0	6	**786**
	DC	371	0	82	0	1,645	0	**2,098**
Onshore grid connection circuit	AC	0	24	4	5	0	1	**34**
	DC	60	0	20	0	159	0	**239**
Total Connection Cost	**£'m**	**3,050**	**1,478**	**1,127**	**423**	**6,713**	**46**	**12,837**
Average cost per kW	**£/kW**	**381**	**246**	**403**	**282**	**442**	**216**	**381**

B.3.3 Onshore connection with UGC

		Wash	North West	Thames	Wales	Dogger	Others	Total
Inter-array cabling		395	296	138	75	750	11	**1,664**
Offshore platform		440	360	161	95	844	14	**1,913**
Converter		1,785	0	510	0	3,315	0	**5,610**
Onshore grid interface		0	320	80	80	0	15	**495**
Submarine cable link	AC	0	478	132	169	0	6	**786**
	DC	371	0	82	0	1,645	0	**2,098**
Onshore grid connection circuit	AC	0	240	20	36	0	6	**302**
	DC	312	0	105	0	835	0	**1,252**
Total Connection Cost	**£'m**	**3,303**	**1,694**	**1,228**	**454**	**7,388**	**51**	**14,119**
Average cost per kW	**£/kW**	**413**	**282**	**439**	**303**	**486**	**242**	**419**

Appendix C Wind Power Output Series

This appendix presents details about the process undertaken and assumptions made in creating the "synthetic" wind Power output record used for the studies presented in the main body of this report. The wind farm output record is created from the addition of the offshore and onshore wind farms output records which are explained below.

C.1 Offshore wind farms output record

C.1.1 Wind power station output analysis

The following describes the methodology used to quantify the half hourly energy influx into electrical network surrounding due to the installation of wind power installed capacity installed in the waters around the southern part of the UK.

The half hourly output of the main seven wind farm clusters indicated in Figure 4.4 (and also including Isle of Wight) is a function of the following variables:

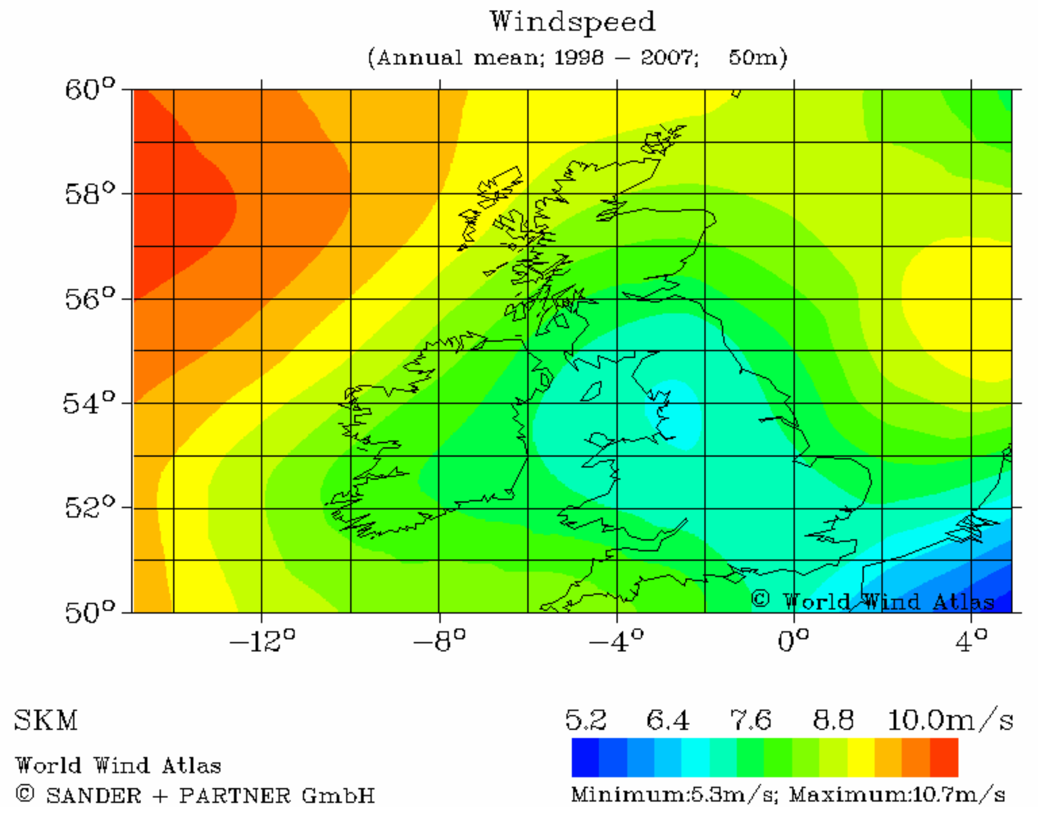
- local wind resource (as seen by these wind farms)
- the characteristics of the turbines installed at each of the wind farms (power curve)
- the efficiency of the wind farms (including wake effects, electrical losses, power curve degradation, availability etc)
- the manner in which the wind farms are operated (including maintenance efficiency)

C.1.2 The local wind resource.

A wind resource for the seven areas has been established based on information evaluated from the following sources:

- World Wind Atlas
- DTI – Atlas of UK Marine Renewable Energy Resources
- BERR – UK Offshore Energy Sea (Dec 2007)

Figure 7.3 long term mean wind speed from the WWA at 50mAMSL



The information from the above sources provides the long term average wind speed for each of the 7 areas as shown below:

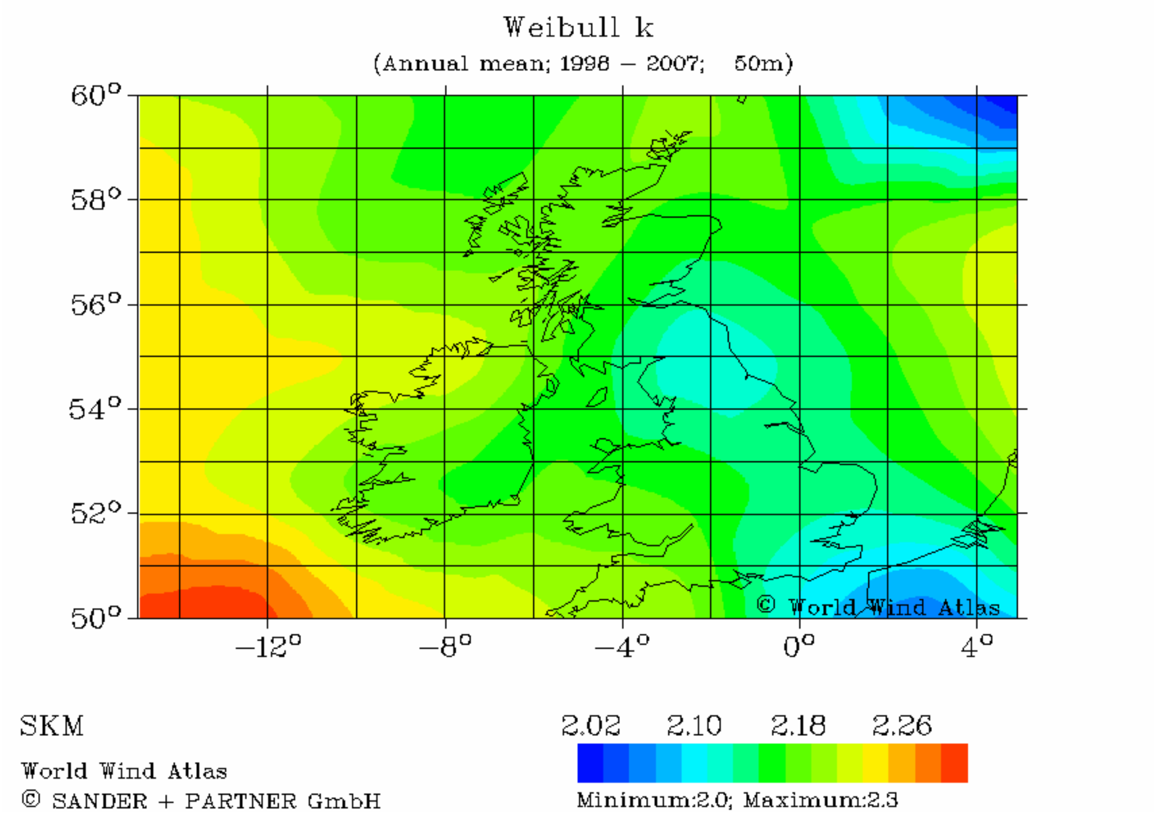
Table 7.20 Mean wind speeds for 7 target areas

	min	max	mean	min	max	mean	min	max	mean	*average*
Dogger Bank	9.58	10.02	9.80	9.34	9.76	9.55	10.03	10.36	10.20	***9.85***
Norfolk	8.71	9.14	8.93	8.32	9.24	8.78	8.91	9.68	9.30	***9.00***
London	7.84	8.27	8.06	8.83	9.24	9.04	8.46	9.31	8.89	***8.66***
Isle of Wight	8.27	8.71	8.49	9.34	9.76	9.55	9.31	9.68	9.50	***9.18***
Severn Estuary	8.27	8.71	8.49	8.32	9.24	8.78	9.31	9.68	9.50	***8.92***
Wales	7.84	8.27	8.06	8.83	9.76	9.29	8.91	9.68	9.30	***8.88***
North West	7.84	8.27	8.06	9.34	9.76	9.55	9.31	9.68	9.50	***9.04***
	WWA data			DTI wind speed data			BERR wind power density data			

The above long term annual mean wind speeds is valid for a height above mean sea level of 100meters, which is assumed to be the hub height of the proposed wind turbines.

The distribution of long term wind speed can be described by Weibull distribution curves using two variables namely a scale factor and a shape-factor (or k-factor). The scale factor is based on the mean wind speed and the k-factor. The k-factor is assumed to be on average k=2.2. This has been derived (extrapolated up to hub height) from the WWA information valid for 50mAMSL as shown below:

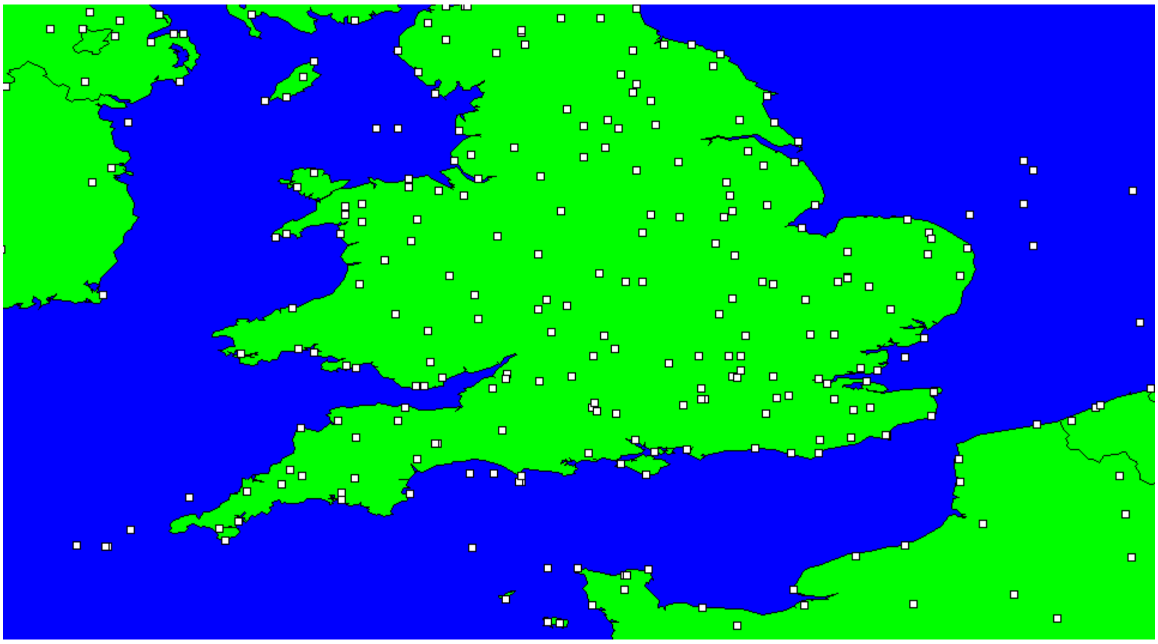
Figure 7.4 long term mean k-factor from the WWA at 50mAMSL



The above long term mean data and k-factor are used to scale time series of wind speed data that is available from met stations in the areas near the offshore wind farm areas. This results in hourly wind speed time series for all the offshore wind farm areas, which in combination is then used to provide time series of power output.

A map with local met stations used to calculate the power time series for the offshore wind farm areas is shown below:

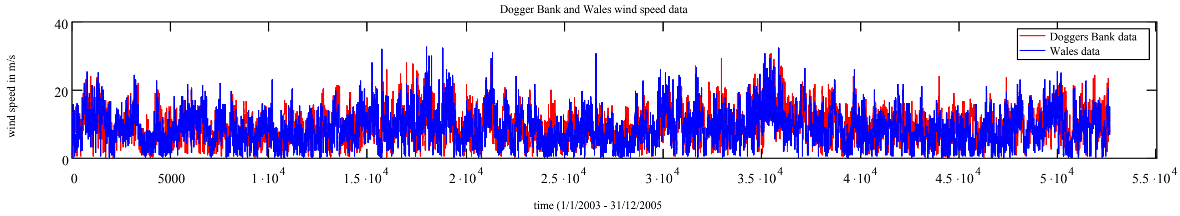
Figure 7.5 Location of NOAA met stations used in this study



- Met station data is based on the NOAA data base of global met stations
- Four met stations have been used for each of the offshore wind farm areas (a total of 27 met station data series has been evaluated). Note that only 3 data series were used for the Wales area. A total 3-year period of hourly time series were used in the analysis
- Met station data included erroneous and missing values which have been excluded from the analysis. Correlation curves and correlation coefficients were determined for all combinations of data series. These correlation curves were used to identify and correct erroneous data in each of the 27 time series. This analysis resulted in producing time series; one 3-year hourly time series for each of the offshore wind farm areas
- Hourly data was interpolated to provide half hourly data.
- Data sets were further processed to remove non-linearities due to measurements and by converting the data sets to time series valid for the chosen locations and chosen hub heights. This was done using standard Weibull distribution curves with shape factor k=2.2 and scale factors based on the expected long term average wind speeds as shown above; this includes the extrapolation from monitored data to hub height data

The resulting data contains half hourly data from 1 Jan 2003 00:00 up to 31 Dec 2005 23:30. The data is based on the NOAA data bank utilising measurements taken at the UK met station sites in accordance with the WMO standards. The data shows long term Weibull distribution curve characteristics while keeping its time characteristics, thus allowing it to be synchronised with time dependent demand data for the same time period. Indeed all offshore wind farm traces are synchronised in time, all are a true representation of the long term wind speed characteristics and all are true in regards to the measured interdependency in time.

Figure 7.6 Dogger Bank and Wales half hourly wind speed data

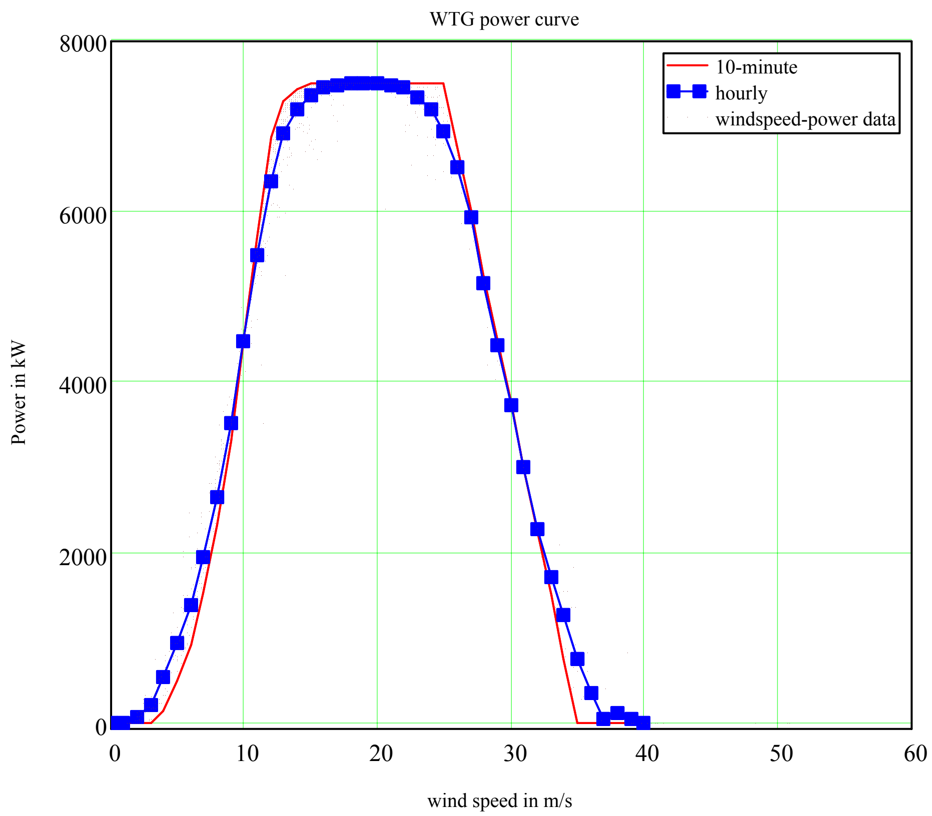


C.1.3 Wind Turbine characteristics

The above wind speed will have to be converted in power data. This is done by combining the wind farm power curves with the wind speed time traces.

In the analysis a 7.5 MW wind turbine power curve has been used. Its power curve is based on the extrapolation of existing large scale off shore wind turbine power curves. The power curve as shown in Figure 7.7 includes a sloped trailing edge, thus gradually reducing the power output above ‘normal’ 25 m/s cut out wind speeds. It is noted that this control feature has already been implemented in several turbine manufacturers, notably the Enercon series of turbines specifically designed for high wind speed regimes. Normal power curves are based on 10-minute values. The power curve shown below is based on hourly average wind speeds in order to account for inter-hour wind speed variations and slight geographic spread within the individual 500 MW wind farms and 7 clusters.

Figure 7.7 Generic 7.5 MW wind turbine power curve



C.1.4 Power output data series

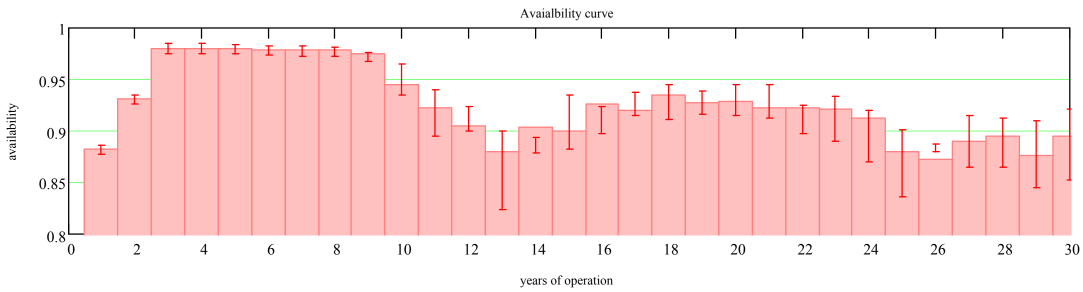
The half-hourly power output data series is based on a gross output of the individual wind farms. The following system inefficiencies have been taken into account.

- Availability of the turbines
- Array and wake losses
- Columnar losses (if any)
- Electrical losses within wind farm
- Sub station losses
- Electrical losses to metering point
- Hysteresis losses
- Power curve variation and degradation
- Air density changes

The assumption has been made that the turbines installed are of a mature design, i.e. no prototypes.

A special note is given in regards to turbine availability. The turbine availability is important in regards to the calculation of expected annual energy production. A mature off shore turbine will likely follow the following 'availability' curve for the 1st 20 years of operation. This curve is based on failure rates of main turbine components as well as mean time to repair (taking the offshore conditions into account). The mean availability is for the 1st 20-years about 93.7% (long term availability might be slightly lower at 90.9%).

Figure 7.8 Availability curve for a mature 500MW offshore wind power station



The half hourly power output data series for each of the offshore wind farm sites are time and date stamped to allow synchronisation with demand data.

C.2 Onshore wind farms output record

The onshore wind speed record has been developed in a similar manner as the wind speed record produced for a recent Sinclair Knight Merz's report for the Scottish Executive[38] and was produced by aggregation of independent records produced for Scotland and England and Wales from analysis of long actual meteorological wind speed records.

C.2.1 Scotland

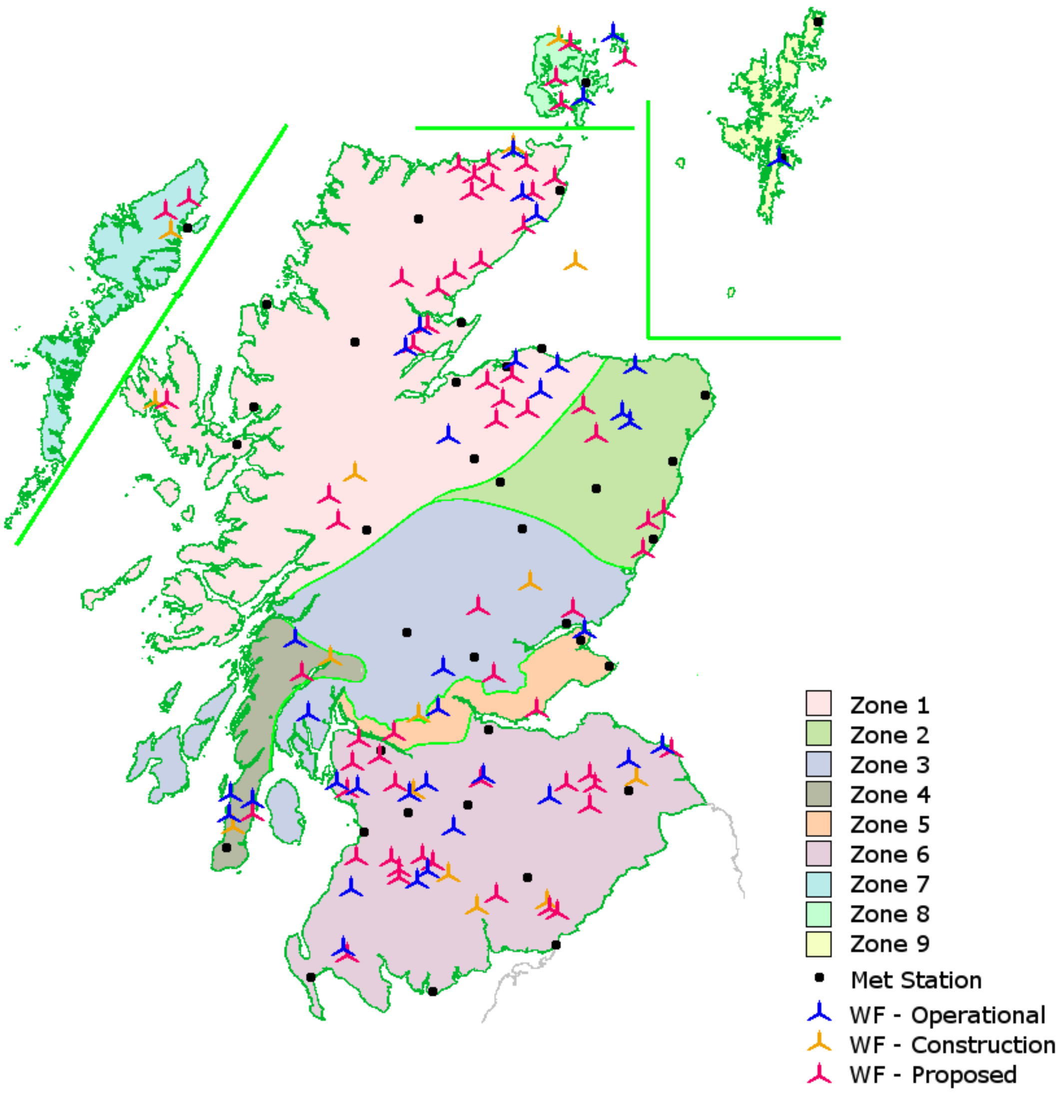
Scotland was split into nine different zones, six zones for mainland Scotland and three for the Western Islands, Orkney and Shetland. For the six zones in mainland Scotland the wind resource will not be the same for each zone. Therefore, in order to develop an overall wind output profile for each zone, several sub-zones (or groups of wind farms in similar locations) have been adopted. These groups have been estimated based on the location of the wind resource, environmental factors and grid infrastructure. The wind resource data has been obtained from the British Wind Energy Association (BWEA), which identifies all the wind farms in various stages of development (i.e. operational, in construction, and planned) within the UK. It is assumed that future wind farms will be located close to the existing and planned new wind farms.

Figure 9 shows the distribution of wind farm locations recorded in the BWEA data plus the existing Metrological Stations (Met. Stations) within the nine different Scottish zones.

---

[38] Sinclair Knight Merz "Grid Issues Arising From Changes to the Generation Background in Scotland", Scottish Executive, May 2008.

Figure 9 Map of Scotland showing selected study zones and BWEA identified wind farms and met stations



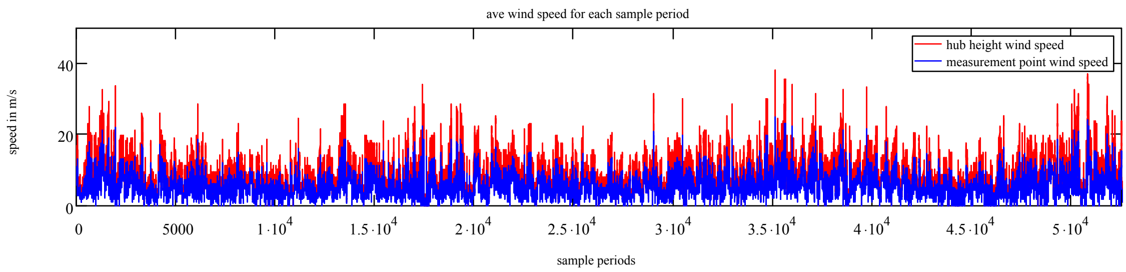
A composite wind resource for each of the nine zones in Scotland has been established based on information evaluated from the most representative Met. Stations within each zone. Depending on geographical size of each zone and the number of currently operational wind farms, a different number of Met. Stations were used in developing each overall zone wind profile. Zones 1 and 6 have been split up into 6 groups, Zone 2 into 3 groups, and Zones 3, 4 and 5 into 2 groups. The wind resource data for Met. Stations in each group have been obtained from the National Climatic

Data Centre (NCDC) database. This data is recorded once every hour at 10 meters above ground level (AGL).

For each of the nine zones a data file containing half hourly wind speed data has been established based on the measured meteorological data. The Met. Station data contained hourly data from 2003 to 2005. This hourly data set has been converted to half hourly values by interpolation, ensuring that the Weibull wind speed distribution characteristics remained unchanged. The data, which was measured at the World Meteorological Organisation (WMO) standard 10m Above Ground Level (AGL) measurement height, has been extrapolated to hub height of the generic turbines using the mean wind speeds at hub height from the UK Numerical Objective Analysis of Boundary Layer (NOABL) database. A standard hub height of 80m AGL is used.

A 3-year wind speed trace for group 1 of Zone 1 is shown in Figure 10. Wind speed traces have been established for each of the wind farm groups within each zone. The wind speed recorded at 10m AGL has been extrapolated to hub height using the relation with the mean wind speed at 80m AGL from the NOABL database.

Figure 10 Sample of Wind Speed Trace for Group 1 within Zone 1

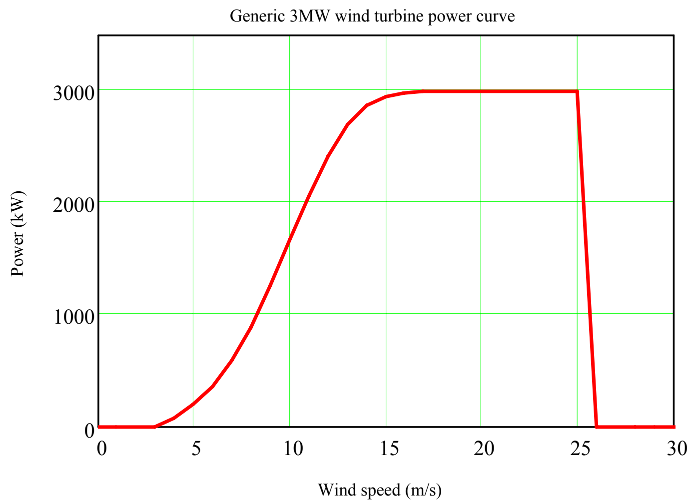


The half hourly output of each zone is a function of the following variables:

- The characteristics (power curve) of the turbines installed at each of the wind farms .
- The efficiency of the wind farms, including wake effects, electrical losses, power curve degradation, availability etc.
- The manner in which the wind farms are operated, including maintenance efficiency.
- Local wind resource, as seen by these wind farms.

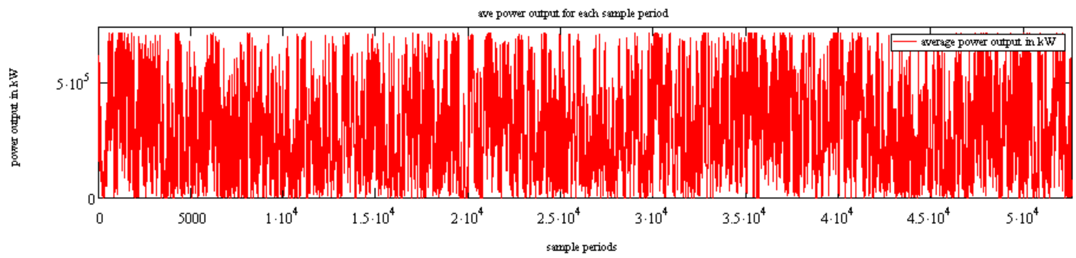
In developing the wind power output profiles for each zone a generic 3 MW wind turbine was adopted, with the typical power curve shown in Figure 11, and a generic wind power station efficiency of 85.3% was assumed. This efficiency value is due to effects which lower the overall efficiency of a wind farm or group or turbines, and includes: wake effects; electrical losses (including switchyard & substation efficiencies); power curve degradation; and losses due to unavailability of wind turbines through maintenance.

Figure 11 Generic 3 MW Wind Turbine Power Curve



Using the group output profiles developed, an overall synthesised wind power output profile was developed for each zone. The half hourly power output data for Zone 1, based on the six groups, is shown in Figure 12.

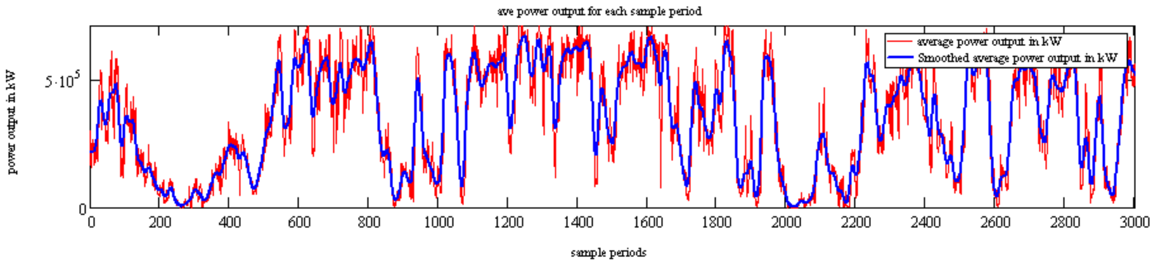
Figure 12 Sample of Wind Power Output Profile for Zone 1



It is important to note that each of the individual group power output profiles have been created from a single Met. Station which have then been combined to create the overall zone profile. While multiple groups have been adopted for zones in the Scottish mainland and would introduce some diversity and smoothing to the overall Scotland power output profile, the resultant profile is still not as smooth as one would expect if the actual outputs from dozens of individual wind farms were summated. To this end we have smoothed the power output profile for each zone by applying a low pass filter, adjusted for each zone based on the existing and likely future geographical spread of wind farms. This process is especially important for the development of the wind output profile for England and Wales, which uses fewer Met. Station sites.

Figure 13 shows the original wind power output profile for Zone 1 and the version with the smoothed power output profile.

Figure 13 Example of Smoothed Wind Power Output for Zone 1



The smoothed power output profiles for each zone were then summated to develop the overall Scottish wind power output profile for the period 2003 to 2005. This process was performed three times, once for each of the three installed wind generation capacities in Scotland.

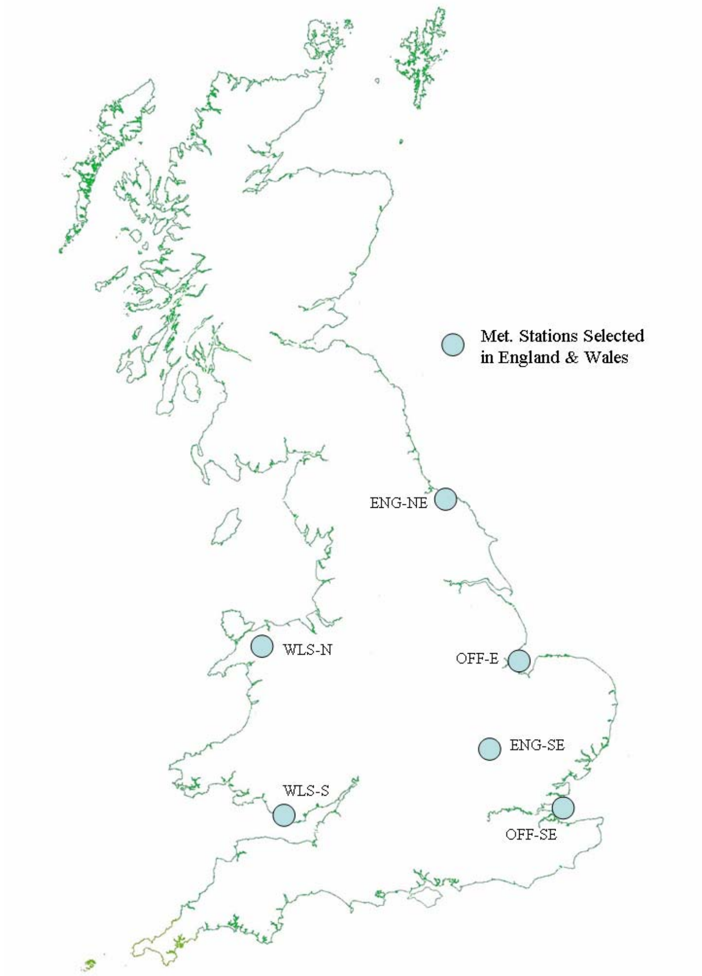
C.2.2 England & Wales

In order to perform aspects of the wind resource correlation analysis and also provide a key input to the system cost studies it was necessary to develop a power output profile for future levels of wind generation to be installed in England and Wales. In developing this profile, six broad areas were considered, as follows:

1. North-East England.
2. South-East England.
3. East England Offshore.
4. South-East England Offshore.
5. Wales North.
6. Wales South.

For each of these six areas a Met. Station site was selected. The locations selected for the six sites are shown in Figure 14.

Figure 14 Met. Stations Selected for England & Wales



For each of the six selected sites the wind speed profile was obtained for the period 2003 to 2005. The six wind speed profiles were then developed into individual power output profiles on a per unit basis, using the same approach as outlined for the Scottish power output profile. Each of the six power output profiles were then smoothed in the same manner as the Scottish zone power outputs, recognising however the significantly larger geographical areas involved.

To enable an overall power output profile to be developed it was necessary to determine an installed wind generation capacity value for England and Wales to accompany the developed Scottish wind output profiles. The per unit smoothed power output profiles for each of the six considered areas were converted to power output profiles commensurate with the installed capacities and summated to yield an overall England & Wales power output profile.