Appendix 3

Resource/Cost Estimates : Onshore Wind to 2010 & 2020

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1. Resource Estimates for Renewable Energy in Ireland to 2020

1.1 Introduction

This appendix sets out the methodology used for estimating renewable energy resources in Ireland to 2010 and 2020. It focuses on the onshore wind energy resources. The resource has been identified in terms of:

- Theoretical Resource
- Technical Resource
- Practicable Resource
- Accessible Resource
- Viable Resource

A subset of the accessible resource identifies the potential for utilizing the resource in terms of what technologies are likely to be implemented with and without Government assistance or intervention. The following section provides the definitions for each resource estimate which have been applied in quantifying each resource to 2010 and 2020. The development of these definitions is discussed in Appendix 7. (Landfill gas and solar thermal resources are dealt with in a similar way in later appendices).

1.2 Resource Definitions

1.2.1 Theoretical Resource

This is the gross energy content of the particular form of renewable energy that occurs within a given space over a given time thereby having the potential to replace fossil energy.

1.2.2 Technical Resource (Subset of Theoretical Resource)

The technical resource is the theoretical resource as above but constrained by the efficiency of the currently available technology to respectively extract renewable energy from the resource or inject it into an electricity or heat using system.

1.2.3 Practicable Resource (Subset of Technical Resource)

This is the technical resource as above, constrained by practical physical or other incompatibilities. E.g. where the resource capture or injection systems simply cannot meaningfully be located due to physical interference or other practical reason.

1.2.4 Accessible Resource (Subset of Practicable Resource)

The accessible resource is the practical resource as above but constrained by man made institutional/regulatory deletions that limit energy extraction e.g. environmental, health and safety, energy policy, planning zonation, by-product management criteria etc. In general all of the accessible resource may not be commercially viable

1.2.5 Viable Resource (Subset of Accessible Resource)

1.2.5.1. Viable Managed Market Resource

Accessible resource as above, constrained by what is considered to be commercially viable at a particular time in the managed or supported market in terms of development cost, scale, resource distribution, market reward level, timing or other risk.

1.2.5.2. Viable Open Market Resource

Accessible resource as above constrained by what is considered to be commercially viable without market support in terms of development cost, resource distribution, market reward level, timing or other risk (Variable over time).

2. Onshore Wind

2.1 Resource Summary

The onshore wind resource for Ireland in 2010 and 2020 is summarised below. The methodology for estimating the resource is provided in the following section in detail.

Table A3.1

Summary of Wind Resource in Ireland to 2020 GWh

GWh	2010	2020
Technical	1,015,900	2,040,801
Practicable	947,969	1,902,023
Accessible	26,202	36,701

2.1.1 Theoretical Resource

The gross annual energy content of the wind resource in Ireland was calculated at 75 meters above ground level using the power production curve from a typical Wind Turbine Generator (WTG). The wind distribution throughout the country is that developed for the Irish Wind Atlas 2003 (Ref. 12).

The Atlas maps the mean wind speed among other variables at heights of 50m, 75m and 100m above ground level throughout the country on a digital database. The national database can be subdivided into counties or other geographical regions. In this instance it was agreed with the client that a suitable representative height for computing the wind resource would be 75m.

A typical wind turbine generator (WTG) is assumed to be 3MW for 2010 and 7MW for 2020. The generators will be geographically placed on a regular grid determined by the minimum practical spacing of the machines. This spacing is determined by using a multiple of five times the blade diameter.

2.1.2 Technical Resource

Theoretical resource calculated as above but constrained by the efficiency of WTG technology to extract energy from wind. The constraint used was to neglect all energy content nationally with a long-term annual hourly mean wind speed of less than 7.5m/s.

2.1.3 Practicable Resource

Technical resource as above, constrained further by practical physical incompatibilities. These physical incompatibilities include airports, roads, lakes, canals, railways, electrical infrastructure, and urban settlements. The physical features are removed from the technical resource using the following additional criteria:

- 400m buffer zone around urban settlements
- 6000m buffer zone along airports (Pending agreement from Irish Aviation Authority)
- 100m buffer zone around the electricity transmission (110kV, 220kV and 400kV) and distribution (38kV) lines.
- Lakes as they exist. Not buffered

2.1.4 Accessible Resource

Accessible resource is defined as the practicable resource but constrained further by social acceptability of installed wind generating capacity in Ireland. This constraint has been estimated to be in the range 5,000 to 10,000MW of wind installed in Ireland.

2.2 Resource Assumptions

The wind resource for Ireland for 2010 and 2020 is detailed in Table A3.2 below which provides a summary of the national accessible wind resource as a function of turbine size utilised.

Table A3.2

National Accessible Wind Resource

Speed Metres/Second	MWh 2010	MWh 2020
7.75	11,961,842	17,350,138
8.25	6,753,267	9,454,744
8.75	3,434,721	4,661,358
9.25	1,941,621	2,561,574
9.75	1,007,317	1,296,814
10.25	545,473	688,054
10.75	299,686	373,173
11.25	152,652	187,855
11.75	68,221	82,784
12.25	27,037	32,716
12.75	7,895	9,447
13.25	2,205	2,590
13.75	593	691
Total	**26,202,530**	**36,701,938**

2.3 Wind Turbine Technology

Resource cost curves have been constructed based on the use of 3MW wind turbines in 2010 and 7 MW wind Turbines in 2020. Note that the capacity factor varies throughout reflecting the usual increase with mean wind speed.

2.4 Cost Assumptions

Table A3.3 below provides the capital and operating cost structures for a 10MW, 7MW and 3MW wind Turbine in 2004 prices.

- The capital costs provided in Table A3.3 have been adjusted for real cost decreases for the year 2010 and 2020.
- The capital costs in 2010 are forecast to decrease (15%) to €4.6 Million (excluding interest during construction) for a 3MW Wind Turbine resulting in a unit cost of €1,546 per kW at 2004 prices.
- The capital costs in 2020 are forecast to decrease (35%) to €6.3 Million for a 7MW Wind Turbine resulting in a unit cost of €902 per kW at 2004 prices.

Table A3.3

Cost Structures for 10, 3 and 7MW Wind Farms

Project Capacity	MW	10	7	3
		10	78%	43%
Site Procurement	000€	20	16	9
Pre Financial Close Costs	000€	40	31	17
EIA	000€	40	31	17
Engineering	000€	40	31	17
Financial and Legal costs	000€	80	62	34
Post Financial Close Costs	000€			
EPC Contract	000€			
Plant	000€	8,200	6,388	3,530
Civil Works	000€	1,100	857	474
Engineering	000€	600	467	258
Contingency	000€	495	386	300
Interconnections	000€			
Electrical Intercomnnection	000€	1,000	779	431
Other Costs	000€			
Owner Engineering, Project mgt	000€	250	195	108
O&M Mobilisation	000€	5	4	2
Contingencies	000€	594	462	256
Spares	000€	10	8	4
Total Investment Costs Excl IDC	000€	**12,474**	**9,718**	**5,457**
	000€			
Unit Cost	Euro/MW	1,247	1,388	1,819
Total Investment Costs	000€	**12,474**	**9,718**	**5,457**
O&M				
	Cents/therm & Euros per GJ			
Land Lease Payments	000€	50	39	22
Salaries and Owner Maintenance Costs	000€	120	93	52
Insurance	000€	62	49	27
Rates	000€	87	68	38
Owners General and Administrative Costs	000€	10	8	4
TUOS Maintenance Charge	000€	16	12	7
TUOS Charge	000€	88	69	38
Annual O&M Costs	000€	**434**	**338**	**187**
		2004	**2020**	**2010**
Capital Cost as proportion of 10 MW		12,474	9,718	5,457
Capital Cost Reduction Time over 2004 prices			35%	15%
Forecast Capital Cost		12,474	6,316	4,638
Forecast Unit Cost (Euro/MW)		1,247	902	1,546

2.5 Outputs

Outputs in MWh for the accessible resource and the number of wind turbines have been generated using the Wind Atlas for Ireland (2003) for each of the thirteen mean wind speed levels. The outputs for each level are shown in Table A3.8 and A3.9 below for 2010 and 2020 respectively.

Table A3.4
Forecast Levelised Cost Analysis by Wind Speed Level 2010

LEVELISED COST ANALYSIS 2010 7.75	Units		11.25	Units	
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	10,585	NPV 20 years	M€	70
Annual Plant Output	MWH		Annual Plant Output	GWh	
PV of Total Output	MWH	117,443,131	PV of Total Output	GWh	1,498,761
Levelised Cost 20 years	Cents KWh	9.01	Levelised Cost 20 years	Cents KWh	4.70
Discount Rate (WACC)	%	**8.00%**	**Discount Rate (WACC)**	**%**	**8.00%**
8.25			**11.75**		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	5,178	NPV 20 years	M€	30
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	66,304,576	PV of Total Output	GWh	669,808
Levelised Cost 20 years	Cents KWh	7.81	Levelised Cost 20 years	Cents KWh	4.49
Discount Rate (WACC)	%	**8.00%**	**Discount Rate (WACC)**	**%**	**8.00%**
8.75			**12.25**		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	2,338	NPV 20 years	M€	12
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	33,722,601	PV of Total Output	GWh	265,448
Levelised Cost 20 years	Cents KWh	6.93	Levelised Cost 20 years	Cents KWh	4.35
Discount Rate (WACC)	%	**8.00%**	**Discount Rate (WACC)**	**%**	**8.00%**
9.25			**12.75**		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	1,196	NPV 20 years	M€	3
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	19,063,123	PV of Total Output	GWh	77,516
Levelised Cost 20 years	Cents KWh	6.28	Levelised Cost 20 years	Cents KWh	4.23
Discount Rate (WACC)	%	**8.00%**	**Discount Rate (WACC)**	**%**	**8.00%**
9.75			**13.25**		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	572	NPV 20 years	M€	1
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	9,889,983	PV of Total Output	GWh	21,649
Levelised Cost 20 years	Cents KWh	5.79	Levelised Cost 20 years	Cents KWh	4.14
Discount Rate (WACC)	%	**8.00%**	**Discount Rate (WACC)**	**%**	**8.00%**
10.25			**13.75**		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	290	NPV 20 years	M€	0.2
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	5,355,530	PV of Total Output	GWh	5,822
Levelised Cost 20 years	Cents KWh	5.41	Levelised Cost 20 years	Cents KWh	4.06
Discount Rate (WACC)	%	**8.00%**	**Discount Rate (WACC)**	**%**	**8.00%**
10.75					
Project Life					
Number of Units					
Capital Costs	M€				
O&M Costs	M€				
Sub Total	M€				
NPV 20 years	M€	148			
Annual Plant Output	GWh				
PV of Total Output	GWh	2,942,361			
Levelised Cost 20 years	Cents KWh	5.03			
Discount Rate (WACC)	%	**8.00%**			

Table A3.5
Forecast Levelised Cost Analysis by Wind Speed Level 2020

LEVELISED COST ANALYSIS 2020					
7.75	Units		11.25		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	6,783.2	NPV 20 years	M€	45.2
Annual Plant Output	MWH		Annual Plant Output	GWh	
PV of Total Output	MWH	170,346,217	PV of Total Output	GWh	1,844,386
Levelised Cost 20 years	Cents KWh	3.98	Levelised Cost 20 years	Cents KWh	2.45
Discount Rate (WACC)	%	**8.00%**	Discount Rate (WACC)	%	**8.00%**
8.25			11.75		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	3,318.3	NPV 20 years	M€	19.3
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	92,828,067	PV of Total Output	GWh	812,787
Levelised Cost 20 years	Cents KWh	3.57	Levelised Cost 20 years	Cents KWh	2.37
Discount Rate (WACC)	%	**8.00%**	Discount Rate (WACC)	%	**8.00%**
8.75			12.25		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	1,498.4	NPV 20 years	M€	7.4
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	45,765,902	PV of Total Output	GWh	321,211
Levelised Cost 20 years	Cents KWh	3.27	Levelised Cost 20 years	Cents KWh	2.30
Discount Rate (WACC)	%	**8.00%**	Discount Rate (WACC)	%	**8.00%**
9.25			12.75		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	766.6	NPV 20 years	M€	2.1
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	25,149,912	PV of Total Output	GWh	92,753
Levelised Cost 20 years	Cents KWh	3.05	Levelised Cost 20 years	Cents KWh	2.27
Discount Rate (WACC)	%	**8.00%**	Discount Rate (WACC)	%	**8.00%**
9.75			13.25		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	366.8	NPV 20 years	M€	0.6
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	12,732,308	PV of Total Output	GWh	25,427
Levelised Cost 20 years	Cents KWh	2.88	Levelised Cost 20 years	Cents KWh	2.26
Discount Rate (WACC)	%	**8.00%**	Discount Rate (WACC)	%	**8.00%**
10.25			13.75		
Project Life			Project Life		
Number of Units			Number of Units		
Capital Costs	M€		Capital Costs	M€	
O&M Costs	M€		O&M Costs	M€	
Sub Total	M€		Sub Total	M€	
NPV 20 years	M€	185.8	NPV 20 years	M€	0.2
Annual Plant Output	GWh		Annual Plant Output	GWh	
PV of Total Output	GWh	6,755,417	PV of Total Output	GWh	6,780
Levelised Cost 20 years	Cents KWh	2.75	Levelised Cost 20 years	Cents KWh	2.23
Discount Rate (WACC)	%	**8.00%**	Discount Rate (WACC)	%	**8.00%**
10.75					
Project Life					
Number of Units					
Capital Costs	M€				
O&M Costs	M€				
Sub Total	M€				
NPV 20 years	M€	94.8			
Annual Plant Output	GWh				
PV of Total Output	GWh	3,663,869			
Levelised Cost 20 years	Cents KWh	2.59			
Discount Rate (WACC)	%	**8.00%**			

2.6 Social Acceptability of Wind Farms

2.6.1 Introduction

There are physical constraints on wind farm siting (free space, ground conditions etc) and the economic (wind speed, ground conditions, access, land ownership) which are estimated using geographically based approaches to producing the 'practical' cost resource curves. In addition to this the other major constraints wind farms face are connection to the electricity network and obtaining planning permission. It is necessary to estimate the effect of both of these in order to get a feel for the accessible resource – the resource that may get built. This section indicates an approach to estimating the effect of planning permission, which depends on the public acceptability of wind farms.

2.6.2 Public Attitudes to Wind Farms in Ireland and other European Countries

Information on attitudes towards the development of wind farms in Ireland is available from a survey recently published by Sustainable Energy Ireland. (Ref. 3)

Key findings include:

1. There is a high degree of support for more wind farms in Ireland
2. The degree of support for wind farms is stronger amongst those who already live near wind farms.
3. Where there is already a wind farm, most local people would view further development favourably
4. If there is further development most people would prefer a new wind farm to an extension of the current one.
5. The public prefer fewer, larger turbines to more smaller ones.
6. The public prefer more smaller farms to fewer bigger ones.
7. Large wind farms (25 turbines or more) were not favoured

The most general of these findings (points 1-3) are similar to those from surveys undertaken in the UK of which the most recent is (Ref. 4)

Studies in Germany and Denmark where levels of installed wind capacity are much higher are of interest. According to a survey of surveys, (Ref. 5), they also show the same pattern – the general population supports wind farms, and support is stronger where people live near existing wind farms. This paper warns that the general support always drops when a specific wind farm is proposed but that this generally recovers once the wind farm is built. The degree of openness, consultation and local involvement in a wind farm is key in securing local support.

The most striking of the surveys quoted is of an area of Denmark, the municipality of Sydthy conducted in 1997. Sydthy has 12,000 inhabitants and more than 98 per cent of the total electricity consumption is covered by wind power. This means that Sydthy is one of the places in the world with the highest concentration of wind turbines. However, the level of support for further wind farm development was still high.

It should be born in mind that in Denmark there is a tradition for wind co-operatives, where groups of people share a wind power plant. In that respect Sydthy municipality is quite unique with 58 % of the households having one or more shares in a co-operatively owned wind turbine. Regarding the general attitude towards wind turbines, the picture is clear. People who own shares in a turbine are significantly more positive about wind power than people having no economic interest in the subject. Members of wind co-operatives are more willing to accept erection of a turbine near them.

The evidence from Sydthy suggests that support for wind farms in Ireland will not fall away even if the number of wind farms increases significantly from current levels, provided that they are consulted and given an opportunity to be involved.

2.6.3 Wind Capacity Density in other EU Countries

It is difficult to compare the pattern of wind development between countries. There are differences in the physical resource; the electricity infrastructure; the electricity market; Government policy and incentives for development and the wider economy as well as public acceptability. It is not simple therefore to separate out the effect of public acceptability from these other factors.

The table below (A3.2) illustrates this: it shows the physical size, population, population density, and onshore wind capacity of four European countries: Denmark (with the longest tradition of wind development), Germany (with the most installed capacity), the UK and Ireland.

Clearly the size of the country and the population affect the accessible resource, so two other columns show the 'density' of wind capacity expressed per 1000 people of the population and also per square kilometre.

Table A3.6

Wind Capacity Density

Country	Area (in sq km)	Population in 1997 (in 1000s)	Population density (inhabitants per km^2)	Onshore Wind capacity at end of 2003 (MW)	Onshore wind capacity per population (MW/1000 people)	Onshore wind capacity density (MW/sq km)
Denmark	43094	5236	122	3046.2	0.582	0.0707
Germany	356974	80567	226	14609	0.181	0.0409
UK	241752	57854	239	649	0.011	0.0027
Ireland	70285	3605	51	186	0.052	0.0026
				max	**0.582**	**0.0707**
				min	**0.011**	**0.0026**

There is a considerable range in these values. Expressed as capacity per head of population, Denmark (the highest) has over 50 times the capacity of the UK (the lowest). In wind capacity density Denmark (again the highest) has nearly 30 times that of the UK. This in spite of a much better physical wind resource in the UK, although Denmark has roughly half the population density of the UK, which may be a contributing factor.

One way of estimating the 'acceptable' wind capacity therefore is to take the density values for Denmark and apply them to Ireland. These would give two figures:

- Onshore wind capacity based on head of population: **2000MW** approx.
- Onshore wind capacity based on land area: **4700MW** approx.

There are several factors that would suggest that the figures should be considerably higher than this:

- Ireland has only half the population density of Denmark
- Ireland has considerably higher wind speeds than Denmark
- Although Denmark has the longest history of wind energy within Europe and increasing attention is being paid to offshore wind, the onshore wind market does not appear to be saturated with over 100MW installed in 2003 (more than twice the Irish onshore total for the same year). So these density values should not be seen as an upper limit.
- Many of the turbines in Denmark are older and smaller than currently available machines – so the density of the installed capacity is lower.

2.6.4 Variation of Wind Capacity Density within Germany

Information on area, population and wind capacity is available for Germany by region. Although Germany is ruled federally, by and large the policy and economic drivers for wind energy are common across the country, so one variable is removed. Looking at individual regions demonstrates the wide variation, due largely to the nature of the physical resource. Wind capacity has concentrated in the regions with higher wind speeds, as shown in Table A3.7.

Again there is a considerable range in the density values. Excluding Berlin (with no turbines installed), Schleswig-Holstein (the highest) has nearly 50 times the capacity of the Bavaria (the lowest) expressed both as capacity per head of population and density. This is despite almost identical population densities.

This variation suggests that a regional approach should be taken to estimating the 'acceptable wind capacity' in Ireland.

The maximum wind capacity density figures, per head of population and per km^2 are considerably higher for the highest region (Schleswig-Holstein) than for Denmark. This is despite a higher population density in this region than in Denmark.

Using the density figures from Schleswig-Holstein and applying them to Ireland gives estimates as follows:

- Onshore wind capacity based on head of population: 2800MW approx.
- Onshore wind capacity based on land area: 9000MW approx.

Again there are several factors which would suggest that the figures should be considerably higher than this:

- Ireland has only a third the population density of Schleswig-Holstein.
- Ireland has considerably higher wind speeds than Schleswig-Holstein, so the physical resource will be larger.

- the onshore wind market does not appear to be saturated with 230MW installed in Schleswig-Holstein in 2003 (more than four times the Irish onshore total in the same year). So these density values should not be seen as an upper limit.

Table A3.7

Wind Capacity Density Distribution – Germany

Region	Area (in sq km)	Population in 1994 (in 1000s)	Population density (inhabitants per sq km)	Onshore Wind capacity at end of 2003 (MW)	Onshore wind capacity per population (MW/1000 person)	Onshore wind capacity density (MW/sq km)
Berlin	883	3475.0	3935	0.0	0.000	0.0000
Hamburg	746	1702.9	2283	32.2	0.019	0.0432
Bremen	500	551.6	1103	35.1	0.064	0.0702
Saarland	2567	1080.0	421	35.2	0.033	0.0137
Bavaria	70549	11600.0	164	189.2	0.016	0.0027
Baden-Wurttemberg	35750	10000.0	280	209.3	0.021	0.0059
Hesse	24604	5800.0	236	348.3	0.060	0.0142
Thuringia	16251	2533.0	156	426.6	0.168	0.0263
Rhineland-Palatinate	19834	3926.0	198	601.8	0.153	0.0303
Saxony	18337	4901.0	267	614.9	0.125	0.0335
Mecklenburg-West Pomerania	23838	1890.0	79	927.2	0.491	0.0389
Saxony-Anhalt	20445	2965.0	145	1631.8	0.550	0.0798
Brandenburg	26940	2540.0	94	1806.6	0.711	0.0671
North Rhine-Westphalia	33957	17759.0	523	1822.2	0.103	0.0537
Schleswig-Holstein	15670	2595.0	166	2007.0	0.773	0.1281
Lower Saxony	47384	7480.0	158	3921.6	0.524	0.0828
Totals	**358255**	**80798.5**	225.53349	**14609**	0.181	0.0408
			Max*		**0.773**	**0.1281**
			Min*		**0.016**	**0.0027**

City regions

* Excluding Berlin

2.6.5 Summary and Conclusions

Comparison of the SEI Public Attitude survey with results of those from other European countries suggests that the Irish population is at least as positive about wind farms as that of other countries. Also, importantly, experience of wind farms increases enthusiasm. There is evidence from Denmark that this is true even in areas with an existing high density of wind farms. Acceptability of specific schemes is increased if the public is consulted and involved.

It is difficult to separate out public acceptability from the many different factors affecting the development of wind resource in a given area. Two figures have been calculated to eliminate two possible variables: the area and population of a region. Thus, the onshore wind installed capacity is expressed in MW/head of population and per $km^{2.}$

- These 'wind densities' have been calculated for four Northern European countries. They vary greatly. The highest values were for Denmark. Applying these figures to Ireland give 'publicly acceptable' onshore wind capacities of between 2000 and 4700MW.
- These figures have also been calculated for German regions. Again they vary greatly. This suggests that taking a regional approach for Ireland is preferable.
- The highest density values were for Schleswig–Holstein. Applying these figures to Ireland give 'publicly acceptable' onshore wind capacities of between 2800 and 9000MW.
- Onshore wind development in both Denmark and Schleswig-Holstein is ongoing so these should not be regarded as upper limits
- There are good reasons (amongst them higher wind speeds and lower population densities) for the acceptable capacity being significantly higher in Ireland than either of these areas.

Taking national figures for area and population density into account this analysis suggests that the publicly acceptable onshore wind capacity in Ireland is likely to be in the range 5,000 to 10,000MW, provided the public are consulted and involved in developments.

Both Denmark and Germany have robust wind turbine manufacturing industries whereas Ireland has not. It is possible that the positive attitude expressed in Ireland would be even stronger if there was a sense that home manufacturing industry was being supported by wind farm investment.

2.7 Electricity System and Wind Power

The capability of the electricity system in Ireland, North and South, to accommodate wind power development is dictated by

- the technical and economic characteristics of the thermal plant on the system.
- the ability of the electricity market trading arrangements put in place to handle intermittent and unpredictable generation.

In theory the development of interconnection capacity with Britain should facilitate the development of wind power in Ireland but two issues act as a very significant barrier to developing wind power in Ireland for export to Britain:

1. The present manner in which the Moyle HVDC link is controlled, on the Scottish side

2. The U.K. market arrangements under NETA, which put very high penalties on intermittent power sources.

Thus with present system and market arrangements and an ongoing commitment to use of combined cycle gas turbines as the potential to develop wind power in the Republic is limited to approximately

- 1000MW by 2010 (1300MW on a whole island basis)
- 1250MW by 2020 (1600W on a whole island basis)

assuming very good geographical dispersion.

The relatively modest increase in capacity over the period 2010-2020 is due to ESRI's assumption that economic growth in Ireland will be significantly lower in that period, due to demographic factors. As a result electricity demand growth is projected to slow considerably post 2010, thus limiting the scope for further wind power development.

Because of these factors it must be recognised that the cost of wind power will increase very sharply with increasing levels of wind power penetration unless appropriate strategies are put in place.

The first of these is that the mix of non wind plant on the system is adjusted to complement increasing levels of wind power generation. In the absence of the ability to connect to a network with considerable hydro power capacity and large hydro storage capability the best that can be done is to increase the proportion of thermal peaking capacity and reduce the base load component. Such a strategy would be aided by the recent development of high efficiency open cycle gas turbines, designed for frequent starts.

The tools or means to implement such a strategy and to address these issues require further regulatory measures.

2.8 Accessible Resource Cost Curves

The accessible resource cost curves for wind are shown in Figures A3-1, 2 and Tables A3-8, 9 below. The accessible resources for 2010 and 2020 reflect the turbine sizes utilised and the cost curves have been generated using levelised cost analysis for each of the mean wind speed levels detailed above.

The costs curves below are based on the accessible resource before system and market constraints are taken into account. The existing system and market constraints (1000 and 1250 MW) in 2010 and 2020 respectively significantly reduce the amount of wind resource that could be exploited. A revised plant type could increase this to 3725MW by 2020.

It should be noted that the implied capacity factors used in relating MW and MWh (Table A3-8, 9) vary in line with the wind statistical distribution of Wind Atlas 2003 and the characteristic output curve of the 3MW and 7MW wind turbines selected. Thus the capacity factor used for 2010 varies from 0.26 at 7.75m/sec. wind speed to 0.45 at 12.75m/sec. For 2020 the respective figures are 0.27(7.75) and 0.54(12.75).

This reflects the improved performance of a larger wind turbine in a higher wind speed environment. Discount rates of both 6.88% and 8% are used in the tables but the resource cost curves plotted are those for 8%.

The resource cost tables clearly show that under the forecast cost reduction in the analysis wind power can be more competitive than the BNE in 2020. In 2010 this occurs only at the best wind sites. The highest cost region having a mean wind speed of 7.75m/s as shown in Tables A3-8, 9 below is 8.46 and 3.8 Cents/kWh in 2010 and 2020 respectively compared to the BNE level of 4.72 Cents kWh.

Table A3.8 Resource Costs by Wind Speed Category (2010)

Resource Cost Curve Data - 2010 (3MW)				
Wind Speed	Cents		MW	MWh
	6.88%	8%		
7.75	8.46	9.01	5,182	11961,842
8.25	7.33	7.81	2,535	6,753,267
8.75	6.51	6.93	1,145	3,434,721
9.25	5.89	6.28	586	1,941,621
9.75	5.43	5.79	280	1,007,317
10.25	5.08	5.41	142	545,473
10.75	4.72	5.03	72	299,686
11.25	4.41	4.70	34	152,652
11.75	4.21	4.49	15	68,221
12.25	4.08	4.35	6	27,037
12.75	3.98	4.23	2	7,895
13.25	3.88	4.14	0	2,205
13.75	3.81	4.06	0	593
TOTAL				**26,202,530**

Table A3.9 Resource Costs by Wind Speed Category (2020)

Resource Cost Curve Data - 2020 (7MW)				
Wind Speed	Cents		MW	MWh
	6.88%	8%		
7.75	3.8	4.0	7,401	17,350,138
8.25	3.4	3.6	3,620	9,454,744
8.75	3.1	3.3	1,635	4,661,358
9.25	2.9	3.0	836	2,561,574
9.75	2.7	2.9	400	1,296,814
10.25	2.6	2.8	203	688,054
10.75	2.5	2.6	103	373,173
11.25	2.3	2.4	49	187,855
11.75	2.3	2.4	21	82,784
12.25	2.2	2.3	8	32,716
12.75	2.2	2.3	2	9,447
13.25	2.2	2.3	1	2,590
13.75	2.1	2.2	0	691
TOTAL				**36,701,938**

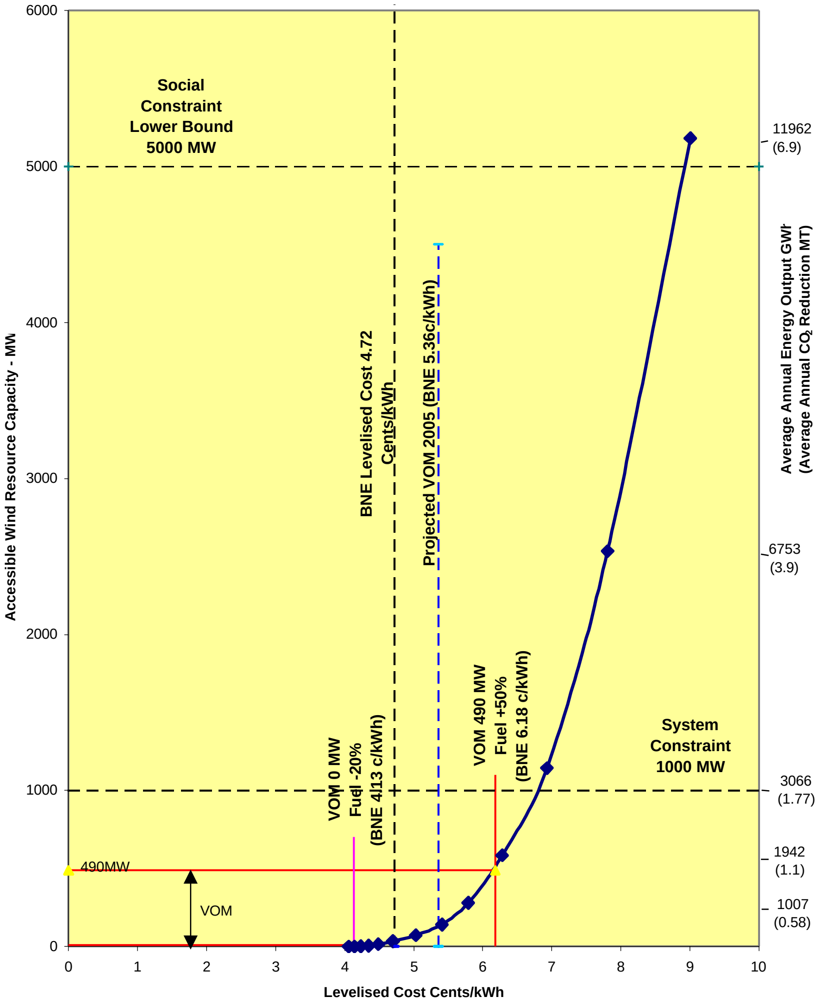
The resource cost curve for 2020 shows a significant shift downwards compared to the resource cost curve for 2010. The accessible resource however after system and market constraints increases by only 250 MW by 2020 to 1250MW.

Figure A3.1

Resource Cost Curve

Wind Generation 2010 at 2004 Prices

(8% Discount Rate)



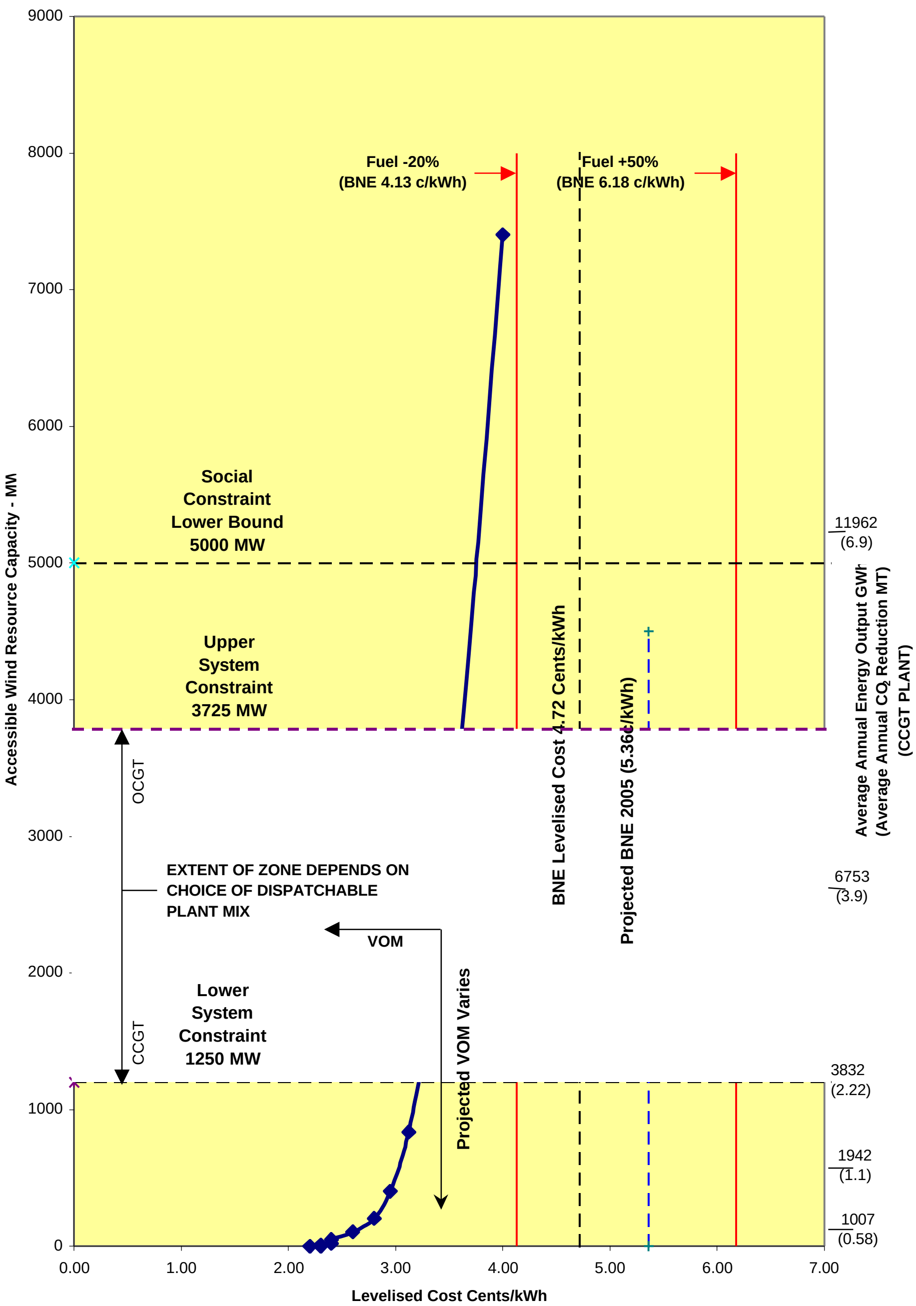
The 1997 study (Ref. 6) suggested that the wind resource would be system limited by 2020. Depending on the load factor achieved for the machines the constrained limit could vary between 550MW (LF 45%) and 820MW (29%). No account was taken of the cross border inter-link. The figures may now be viewed as conservative in the light of experience but the current study suggests that system constraints will still exist and form a serious hurdle to development of the full potential of wind power unless significant reconfiguration of existing and planned thermal plant takes place. Levelised costs for 2020 implied by the current study are well below these projected by the 1997 study reflecting the increase in turbine scale and efficiency that has taken place since then.

Figure A3.2

Resource Cost Curve

Wind Generation 2020 at 2004 Prices

(8% Discount Rate)



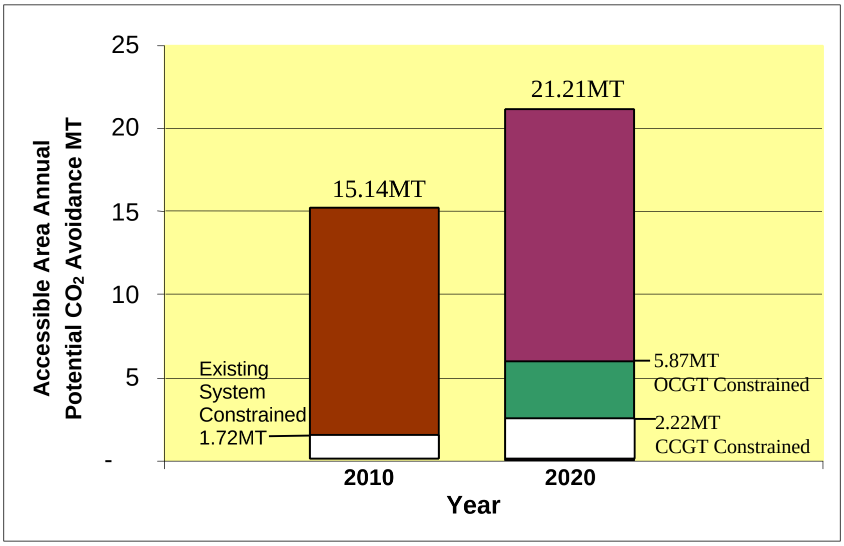
2.9 CO_2 Avoidance from Wind Generation

Based on a forecast mix of generation in 2010, each MWh generated from renewable energy will result in a reduction of 0.578 tons of CO_2. Applying this CO_2 avoidance rate to the accessible wind resource as shown in Figures A3.2, 3 (assuming a capacity factor of 0.35) there are potentials to reduce CO_2 emissions by the following tonnages, based on Table A3.8,9,10, 11.

2010 : Unconstrained (26,202,530 x 0.578)	= 15,145,062T*
Constrained = (1000 x 8760 x 0.35 x 0.578)	= 1,772,148T
2020 : Unconstrained (36,701,938 x 0.578)	= 21,213,720T*
CCGT Constrained (1250 x 8760 x 0.35 x 0.578)	= 2,215,185T
OCGT Constrained (3725 x 8760 x 0.35 x 0.51)	= 5.87MT as per later calculation

Figure A3.3

Potential CO_2 Avoidance from Wind Generation



*Note that capacity factors vary with mean wind speed and are taken account of in MWh totals of Tables A3.8 & A3.9.

The effect of the projected new plant mix (OCGT) would be to reduce CO_2 output from that which would prevail if aging fossil fuelled plant had been retained. However the open cycle machines have a higher CO_2 output per unit of generation than do combined cycle units.

Thus by 2020 the substitution of 1MWhr of wind energy would lead to a lower reduction of CO_2 than would have occurred if it was possible to operate CCGT systems in the mid and peak load ranges.

The plant position for 2016, utilising OCGT machines, has been summarised as follows. (40):

Table A3-10

Plant in Service 2016 – MW

	Base	Mid	Peak	Total
Existing	2395	710	292	3397
Additions	675	910	1208	2793
Subtotal	3070	1620	1500	6190
Wind	3500	-	-	3500

The wind/thermal hydro capacity ratio for 2016 above is 3500/6190 = 0.565. It is projected that electricity output will rise by 3780GWh or 10% between 2016 and 2020 (Table 3.1). Assuming that the projected 2016 plant mix can be prorated upwards to cater for this incremental output it would yield (assuming capacity factors of 0.9 thermal and 0.35 wind):

(0.9 x 8760 x Firm Capacity + 0.35 x 8760 x Wind Capacity) = 3780GWh

or 0.9 x Firm Capacity + 0.35 x Wind Capacity) = 431.5MW

substituting Wind = 0.565 Firm Capacity yields

Firm Capacity = 392.9MW (395MW)

Intermittent/Wind Capacity = 222.6MW (225MW) for 2020.

Again prorating the Firm Capacity into its components yields

Base Load Plant 3070 x 395 ÷6190 = 195.9MW (196)

Mid Load Plant 1620 x 395 ÷ 6190 = 103.3MW (103)

Peak Load Plant 1500 x 395 ÷ 6190 = 95.7MW (96)

Thus the new firm plant totals and possible composition for 2020 are:

Table A3-11

Projected Firm Plant Composition (2020)MW

	Base	Mid	Peak	
	3070	1620	1500	
	196	103	96	
Comprising	3266	1723	1596	
Coal	900	-	-	
Peat	325	-	-	
CCGT	204	-	-	
OCGT	-	1723	1596	
	3266	1723	1596	

Table A3-12

Projected Plant Emissions (2020)

Emission	MW hrs CF	MWh	TCO_2
Coal	900 x 8760 x 0.9 =	7,095,600 @ 900kg/MWh	= 6,386,040
Peat	325 x 8760 x 0.85 =	2,419,950 @ 1150kg/MWh	= 2,782,942
CCGT	2041 x 8760 x 0.9 =	16,091,244 @ 375kg/MWh	= 6,034,216
OCGT	1726 x 8760 x 0.65 =	9,810,762 @ 375kg/MWh	= 3,679,035
OCGT	1596 x 8760 x 0.41 =	5,772,444 @ 400kg/MWh	= 2,308,977
		41,190,000	21,191,210

(It should be appreciated that the above figures can only be crude approximations and that in reality each generating unit has its own curve of CO_2 production versus load level).

Thus the projected mean system fossil CO_2 production per MWh is (21,191,210 ÷ 41,190,000) = 0.514T CO_2/MWh and the CO_2 displaced by (3500 + 225)MW of wind in 2020 would be:

(3725 x 0.35 x 8760 x 0.51) = 5.870MT

This would exceed the 30% CO2 displacement target of 4.9Mt considered in the Government Consultation document (16).

This figure varies depending on the merit order rating of different elements of fossil fuel plant. It would have a lower value if coal or peat plant was only being used for intermediate or peak operation by 2020. The view taken here is that, because of its value in terms of fuel diversification and the investment made in flue gas desulphurisation there and gas price trends, Moneypoint would remain a base load installation but changing circumstances could dictate otherwise.

3. System Integration Issues arising from Wind Power Expansion in Ireland

3.1 Introduction

The extent to which wind power can be accommodated on electricity systems is determined by

- The scale of wind power development in relation to system size.
- The extent to which wind power output is correlated with peak demand or periods of otherwise high loss of load probability.
- The mix of other plant on the system i.e. nuclear, hydro, conventional thermal, combined cycle, open cycle gas turbine.
- The ability to modulate demand.
- The degree of interconnection with other systems and the characteristics of those systems.

These issues are examined in the following sections.

3.2 Scale of Wind Power Developent in Relation to System Size

This is at present a key issue in relation to wind power development in Ireland. The issues involved were clearly identified by ESBNG staff at the Forum on Wind Energy Development on Dec. 17th, 2003 (18).

In the presentation the size of the various independent synchronous networks in Europe was identified as follows.

System	Coverage	Generation Capacity MW
Ireland	Island of Ireland	7,000
G.B.	England, Scotland, Wales	76,000
NORDEL	Norway, Sweden, Finland & Zealand (DK)	83,000
UCTE	Remainder of EU 25 excl. Baltic States & Greece	550,000

From this it is clear that the Irish system is less than one tenth the size of the GB and NORDEL systems and totally insignificant in relation to the UCTE system.

Thus while Ireland has undoubtedly one of the best wind regimes in N. Europe with the potential to generate in excess of 75,000MW at sites with mean wind speeds in excess of 7.0m/s. The ability to exploit that capacity is clearly limited by system size and the overriding need to ensure continuity of supply in periods of low wind output.

3.3 The extent to which Wind Power Output is correlated with Peak Demand or Other Periods of High Loss of Load Probability

In some locations wind power output is closely correlated with periods of high electricity demand. This is particularly true where wind speeds reflect high daily temperature variations and periods of maximum wind speed in specific locations correlate with high electricity demand in the region, particularly air conditioning demand. These conditions are found in areas of California, the Panhandle States in the US and Crete.

Such conditions may also arise in N. West Europe where wind chill unquestionably affects space heating requirements. But the contribution of electric heating to space heating needs has declined very substantially in many countries, with the widespread installation of fossil fuel based central heating systems. Thus electricity demand is now more closely correlated with sunlight than wind speed.

Nonetheless wind speeds in N.W. Europe are generally higher in winter than in summer and thus partially correlated with periods of peak demand. Thus there would appear to be good grounds for accepting the argument put forward by Milborrow (19) that capacity credits for wind power should be based on the mean capacity available during periods of peak demand i.e. the winter months in N.W. Europe. This argument is valid for larger systems where the loss of load probability is highest during periods of peak demand and as a result, on those systems, generation planning is wholly focussed on the ability to meet demand at peak demand periods.

However the combination of a comparatively very small system size in Ireland, coupled with the fact that the unit size for new CCGT plant is the same as used elsewhere, for economic reasons, gives rise to the situation that the LOLP is as high in Ireland during the summer as during the winter, as the tripping of a large unit can coincide with unavailability of other large units, due to forced or maintenance outages.

Thus in Ireland at present the capacity credit for wind power should be based on the annual capacity factor rather the winter capacity factor. This situation could change with the development of HVDC interconnection to Great Britain provided the interconnector is operated with that in mind.

3.4 The Mix of Other Plant on the System

The need to meet the day to day and minute to minute requirement to match production with demand is unique to the electricity sector.

Over the years the electricity sector has developed various approaches to satisfying this need. These include:

- Demand Management
- Pumped storage systems
- Turbine control systems

But there is still a requirement to match the mix of plant on the system to the need to provide the responsiveness to daily, weekly and seasonal demand changes and to provide the necessary spinning reserve capacity to cover for the loss of the largest infeed to the system.

The wind turbines now in service make no contribution to meeting spinning reserve requirements. Thus the ability to cover spinning reserve needs at periods of high wind speeds is particularly problematic. This problem is exacerbated by the fact that although CCGT's have a very good capacity to increase output rapidly, in time periods in excess of 10 seconds, their ability to provide primary spinning reserve in the short term i.e. 5-10 sec. is quite limited and may thus impose limits on wind power output in certain conditions.

This problem could be eliminated if the existing and planned HVDC links were operated in a manner which allowed their technical capacity to increase power flows in very short time frames to be exploited. But this is not the case at present in relation to the Moyle interconnector, for commercial reasons.

The introduction of proportionately large amounts of wind power generation whose output is both intermittent and unpredictable, in the medium term i.e. one day to one week, creates particular problems as wind power is essentially free when available and should thus displace other sources of generation.

In the case of hydro plant this is generally relatively straightforward as hydro output can generally be reduced to minimum levels in the medium term, provided storage facilities are adequate to cater for the inflow in the period. In general ESB's hydro output could readily be reduced to very low levels to accommodate wind output but the installed capacity of ESB's conventional hydro plants in Ireland is only 220MW. Thus if wind power generation were to reach 1350MW on the island there would be a need to displace substantial additional generation at times.

Most pumped storage hydro schemes are designed to facilitate load following, but many schemes such as Turlough Hill are designed to even out daily peaks and troughs and thus their storage capacity is only equivalent to eight hours operation at full output. Thus pumped storage schemes such as Turlough Hill can help even out hourly wind power fluctuations but they are of little use in smoothing medium term wind power output variations.

Thermal plants have differing load following capability, depending on their design.

ESB's conventional thermal plants were generally optimised at 80% of rated output i.e. they achieved their optimum efficiency at that power level. As a result they can be turned down to 50% of rated output with relatively little loss in efficiency and in some cases could be operated at as low as 25% of rated output, although difficulties with NO_x emissions may limit such operation.

In contrast natural gas fired CCGT plants are off the shelf units optimised at 100% rated output and as a result their efficiency falls off relatively sharply as their output is reduced. Furthermore the NO_x emission rate/m^3 rises with declining output and these units are generally unsuitable for operation below 60% of rated output.

The performance of open cycle gas turbines depends on their design. Industrial type units have similar characteristics to large scale CCGT's, aero derived units are more suited to load following.

Nuclear units are generally relatively inflexible as operators generally wish to run these units at base load to minimise the risk of tripping.

The significance of the above in relation to the ability of the electricity system in Ireland to accommodate high levels of wind power output is that post 2005 our projections indicate that natural gas fired CCGT plants will be the marginal generating plant for most of the year.

Thus wind powered generation will have to displace plant with relatively poor turndown capability. As a result in periods of high wind power generation it would be necessary to take CCGT plant off the system if the level of wind power generation exceeding the turn down capability of the hydro and CCGT plant.

Thus ESBNG in its analysis of Feb. 2004 indicate that for the ROI system alone up to 5% wind energy penetration could be accommodated without any adverse impact on the number of starts required p.a. for either base load, mid load or peaking plant. But for higher levels of wind power penetration the number of starts of mid load plant, i.e. the plant at the margin for most of the year expands considerably. This is both costly, as the total cost of starting an F Class CCGT is estimated at in excess of €30,000 and damaging for the plant, in terms of availability and lifespan.

ESBI while agreeing with the modelling approach adopted by ESB NG has concluded that up to 1000MW of wind power could be accommodated on the RoI system by 2010 without seriously increasing the number of starts required of mid load plant.

This divergence of views is believed to be due to a difference in the assumptions made in relation to

- Interconnectors
- The turn down capability of coal fired plant.

3.5 Gas Dependence

It is outside the scope of this report to predict how gas prices may change in the future, rather a mechanism is provided to show how the impact of price changes under stated conditions will be reflected in the price of electricity derived from the Best New Entrant when the price of gas varies. Nevertheless it is sobering to reflect that the dependence on imported gas has now reached a level of over 90%.

A generation ago the prospect of such a dependence on imported oil caused ESB to examine nuclear power as a potential option before the discovery of the Kinsale gas field and the development of the international coal trade eased the position.

There may be a lack of public perception about the relative proportions of natural gas that come from home and oversea sources. The recently approved Corrib field is projected to meet less than 20% of peak day requirements by 2010. (It has been pointed out that the Corrib field has less long term resources than the County Mayo Wind Resource). Based on a number of projections the indications are that future Irish gas trading will be a fraught business where the country

- Lies at the tail end of a sequence of users all of whom will be increasingly dependent on natural gas to fulfil their own requirements.
- Presently lacks a suitable terminal for marine imports, most of which would have to come from relatively unstable regions of the world.
- Depends on a single UK pumping station for its piped imports.
- Is dealing in a commodity whose two way price movement can be extremely volatile on a short term trading basis. Storage of NG is possible in depleted fields as a hedge against wilder short term price movements but this of course implies an inventory cost which will tend to track open market movements (i.e. probably upwards).

As noted elsewhere the CCGT plant is essentially projected to become the base load unit on the Irish system, a role for which it is reasonably well fitted because of its high efficiency but relatively inflexible, mode of operation. This creates a suboptimal situation where mid load and load following plant are concerned.

It is therefore essential that attention should focus on the options that would permit an increased fraction of intermittent energy to be accepted onto the system where it interfaces with such plant.

A range of possible levels of wind penetration can be identified depending on the mix of non wind plant envisaged for the system in the future. The actual decisions to be made on the choice of this plant mix are outside the scope of this report but it is helpful to consider the constraints that arise from these decisions where wind power is concerned, as decisions governing choice of plant post 2010 have to be faced relatively soon due to planning and construction lead times.

Combined Cycle Gas Turbines

The lower boundaries of wind penetration at 1000/1250MW discussed below pre suppose a continued policy of CCGT installation and a reliance largely on the existing portfolio of other fossil fuelled plant.

It has however been pointed out (40) that continued installation of CCGT plant, in addition to increasing the commitment to imported natural gas gives rise to an unbalanced system whose cost effective intermediate and peak load following capacity is limited by the inefficient operation of modern large CCGT plant at levels below about 60% of full load. (This type of ‘off the shelf’ plant is now optimised for operation at about 100% of its capacity. This is evident in the reference case for 2015 considered by a recent ESB National Grid Report (18) where for a peak system demand (Republic) of 6500MW the mid and peak load plant capacity would fall to 16% and 15% respectively, militating against their ability to cope economically or efficiently with intermittent generation sources.

Open Cycle Gas Turbines

The development of large open cycle aero derivative gas turbines is reaching the stage where these can demonstrate rapid start-up and shut down capability with lower costs than previously, efficiencies of up to 45% and potential for installation on existing ESB station sites at about 50% of the cost of BNE CCGT cost. Having regard to the likely doubling of capacity in the Northern Ireland interlink and development of two 500MW interlinks with Britain the successful introduction of these open cycle gas turbines could allow capacities of 1620MW of mid load and 1500MW of peak load plant onto the system for a total capacity of 7345MW on the RoI system in 2016. (This would be sufficient to meet the projected peak of 6500MW and would include 3070MW base load and 3500MW installed wind capacity to yield a wind capacity credit of 1155MW). (40)

This is contingent upon the new open cycle gas turbines meeting their projected performance criteria.

The financial impact of increased commitment to gas fuel is likely to be moderated by the introduction of reinjected storage capacity in one of the depleted gas fields to provide a hedge against the penal cost of short term changes in gas prices.

Biomass and MSW Combustion

These are usually treated as intermediate or base load input particularly where cocombustion, CHP or ‘must take’ considerations apply unless the costs involved place the plant very low in merit order terms.

Pumped Storage

The projected fall in wind generated cost/kW for 2020 suggests that measures other than open cycle gas turbines and gas storage may be warranted to maximise the generation possible from wind (and possibly ocean energy by then). The use of hydro or air storage on a larger scale than hitherto envisaged is an option that merits consideration but is outside the scope of the present report. The challenge of large scale storage is to break through into an area where low incremental cost/kW becomes possible. From a system perspective distributed storage is preferable but in the final analysis this may result in incremental costs that are unsustainable, bearing in mind that storage implies double handling of the storage medium with consequential loss of overall efficiency and economy of scale. An important feature of storage is that it permits decoupling of intermittent energy production from utilisation and also permits arbitrage trading (buying in at a low rate, storing and selling on at premium rates). A case can be made that such

facilities should be for the benefit of all power producers and users and financed by corresponding levies. An area that requires clarification is the apparent anomaly that energy from pumped storage is not treated as a renewable even where renewable power has been used to produce that energy in the first instance.

Assuming therefore that the new OCGT plant fulfils expectations in terms of cost and performance, that interconnection is expanded and that gas storage is adopted as part of an overall energy management strategy and with convergence toward an all island market, it is projected that an upper bound on wind capacity penetration of circa 3500MW would become possible by about circa 2016 at the earliest. It is projected (Table 3.1) that electricity output will increase from 37400GWh to 41200GWh to meet demand between 2016 and 2020, an increase of 3780GWh or 10%.

Thus a feasible upper boundary of about 3725MW of installed capacity for intermittent energy plant can be projected for 2020 and is shown on Figure A3.2.

Clearly the number of variables that influence the achievement of this level of penetration will require the conduct of ongoing well informed and integrated sensitivity studies to determine realistic interim solutions that may exist at different stages en route to the objective of achieving an optimal level of renewable participation in the overall resource mix on the supply side.

3.6 The Ability to Modulate Demand

Electrical utilities have traditionally sought to discourage demand at peak periods and encourage off peak demand by means of pricing incentives.

The peaking penalties were targeted at larger customers who had the capacity to reduce demand at peak periods. However the development of a competitive market for these customers and the introduction, by CER, of a “top up and spill” pricing regimes which did not reflect peak generation costs resulted in the break down of the peak penalty pricing regime and resulted in a significant decline in system load factor in 2002/03.

Since then ESB NG, at the request of CER has introduced an incentive system designed to restore the incentive to reduce demand at peak periods. However the capacity to modulate demand has declined significantly in recent years as many of the larger, price sensitive electricity customers have ceased operations.

3.7 The Degree of Interconnection with Other Systems and the Characteristics of Those Systems

As indicated earlier the size of the synchronous system to which wind power generation is connected is a critical factor in relation to the ability of the system to accommodate that generation. But asynchronous connection with other systems helps as is clear from the experience in W. Denmark, which is asynchronously connected with the NORDEL system as well as being synchronously connected to the UCTE system.

An important point in this regard is that the NORDEL system, which has a total capacity of 85,000MW includes 47,000MW of hydro powered generation.

As indicated earlier hydro generation is an ideal complement to wind power generation as, for systems with a considerable proportion of hydro power, the key problem is meeting the annual MWh demand rather than the peak demand.

Thus the incorporation of intermittent wind power generation in such a system generally presents no system issues.

In contrast the electricity system in England, Scotland and Wales has proportionately very little hydro. Thus were wind power in Great Britain to be developed as now proposed by the U.K. Government the system problems would be similar to those in Ireland, except that the provision of spinning reserve is not a significant problem in a system of that size.

Thus interconnection with Great Britain could eliminate spinning reserve difficulties in Ireland and would reduce any within day problems of accommodating wind, due to improved geographic dispersion. But the medium term problems of accommodating wind, including its impact on daily gas demand and requirements, particularly in summer months, would not be resolved by interconnection, as wind output in Great Britain is likely to mirror that in Ireland in the medium term. (39)

3.8 Constraints on Inter System Electricity Trading

There is sometimes a perception that interconnection is the solution to all system constraints on wind power development in Ireland.

However to date there appears to have been little analysis of how the output from wind farms in Ireland would be treated in an All Islands System.

One view in the wind industry appears to be that Britain would provide

- A potentially very large outlet for Irish wind power generation
- A highly lucrative market for Irish wind power generation, given the Renewables Obligation.

Both these views could be valid provided that

- The output from some wind farms is designated as being hypothecated to the British market.
- The U.K. authorities accept that wind power output in Ireland is treated as satisfying the renewable obligation in British markets.

While the former could clearly be arranged, to date the U.K. Government has refused to accept that renewable output from any jurisdiction which does not have a Renewable Obligation, similar to that originally in place in England and Wales, would qualify under the Renewable Obligation regime. Indeed the original Statutory Instrument setting down the Renewable Obligation rules specifically excluded renewable generation from N. Ireland as it did not then have a similar regime in place. Thus access to the G.B. market is conditional on the Irish authories introducing an effectively identical scheme.

In addition the operation of the New Electricity Trading Arrangements in England and Wales has created significant cost barriers for individual generators, or those unable to accurately forecast their hour by hour output before gate closure.

Thus while the provision of an East-West interconnector may technically facilitate the development of wind farms in Ireland to supply the demand for renewables in Britain, it is clear that there are significant institutional and commercial barriers encountered in converting the potential to reality.

An alternative approach is to assume that the provision of an East-West link would permit the level of wind power generation to be increased beyond the turn down capability of the thermal plant on the system and that electricity could then be imported from Great Britain in periods of low wind output.

This approach would be feasible if the level of wind power penetration in Great Britain, was low but would not apply if the U.K. Government’s current targets for wind power development in Great Britain were achieved, as the problems of turning down thermal plant output, to accommodate wind power generation, would be the same in that market as in Ireland.

4. Conclusions

(1) Results of public attitude surveys in Ireland and other north European countries have indicated a generally high degree of support for wind farm development particularly among those who already live near them.

(2) Extending the public attitude surveys to examine possible limiting scenarios on public tolerance of wind farm capacity based on experience elsewhere suggests that a range as high as 5-10 GW of capacity might be socially possible provided that the public are consulted and involved in the developments.

(3) Wind energy has barely the potential to compete in terms of viable open market levelised cost with fossil fuel electricity generation in 2010. Its cost competitiveness is projected to increase rapidly over the period to 2020 depending on the rate of capital cost reductions and possible fuel price increase.

(4) In theory, on an intermittent basis, the potential electricity that could be generated from wind is sufficient to provide all of Ireland's generation requirements. However this is not feasible because of the additional costs associated with standby generation facilities and the additional operation and maintenance costs of the total electrical generation and transmission system.

(5) On the other hand a set of real issues associated with the capability of the total Irish electrical systems ability to accept input from intermittent sources (such as wind) would raise the real likelihood of enforced limitations on permissible wind power capacity to 1,000MW in 2010 and 1,250MW in 2020.

(6) However the introduction of open cycle gas turbines instead of combined cycle gas turbines as intermediate and peak load plant provides a basis for allowing larger penetration by wind power in the years following 2010. If the OCGT plant performs as projected this could allow about 3725MW of wind capacity onto the system by 2020.

(7) The importance of developing an economically optimal solution to the issue of wind/fossil/hydro plant mix and interconnection requires immediate continued attention.