WIND ENERGY - THE FACTS

PART III

THE ECONOMICS OF WIND POWER

Acknowledgements

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PART III INTRODUCTION

Wind power is developing rapidly at both European and global levels. Over the past 15 years, the global installed capacity of wind power increased from around 2.5 GW in 1992 to just over 94 GW at the end of 2007, an average annual growth of more than 25 per cent. Owing to ongoing improvements in turbine efficiency and higher fuel prices, wind power is becoming economically competitive with conventional power production, and at sites with high wind speeds on land, wind power is considered to be fully commercial.

Part III of this volume focuses on the economics of wind power. The investment and cost structures of land-based and offshore turbines are discussed. The cost of electricity produced is also addressed, which takes into account the lifetime of turbines and O&M costs, and the past and future development of the costs of wind-generated power is analysed. In subsequent chapters, the importance of finance, support schemes and employment issues are discussed. Finally, the cost of wind-generated electricity is compared to the cost of conventional fossil fuel-fired power plants.

Wind power is used in a number of different applications, including grid-connected and stand-alone electricity production and water pumping. Part III analyses the economics of wind energy, primarily in relation to grid-connected turbines, which account for the vast bulk of the market value of installed turbines.

III.1 COST OF ON-LAND WIND POWER

Cost and Investment Structures

The main parameters governing wind power economics include:

- investment costs, such as auxiliary costs for foundation and grid connection;
- operation and maintenance costs;
- electricity production/average wind speed;
- turbine lifetime; and
- discount rate.

The most important parameters are turbine electricity production and investment costs. As electricity production depends to a large extent on wind conditions, choosing the right turbine site is critical to achieving economic viability.

INVESTMENT COSTS

The capital costs of wind energy projects are dominated by the cost of the wind turbine itself (ex-works).[1] Table III.1.1 shows the typical cost structure for a 2 MW turbine erected in Europe. An average turbine installed in Europe has a total investment cost of around €1.23 million/MW. The turbine's share of the total cost is, on average, around 76 per cent, while grid connection accounts for around 9 per cent and foundations for around 7 per cent. The cost of acquiring a turbine site (on land) varies significantly between projects, so the figures in Table III.1.1 are only to be taken as examples. Other cost components, such as control systems and land, account for only a minor share of total costs.

Table III.1.1: Cost structure of a typical 2 MW wind turbine installed in Europe (2006-€)

	Investment (€1000/MW)	Share (%)
Turbine (ex-works)	928	75.6
Foundations	80	6.5
Electric installation	18	1.5
Grid connection	109	8.9
Control systems	4	0.3
Consultancy	15	1.2
Land	48	3.9
Financial costs	15	1.2
Road	11	0.9
Total	1227	100

Note: Calculations by the author based on selected data for European wind turbine installations.

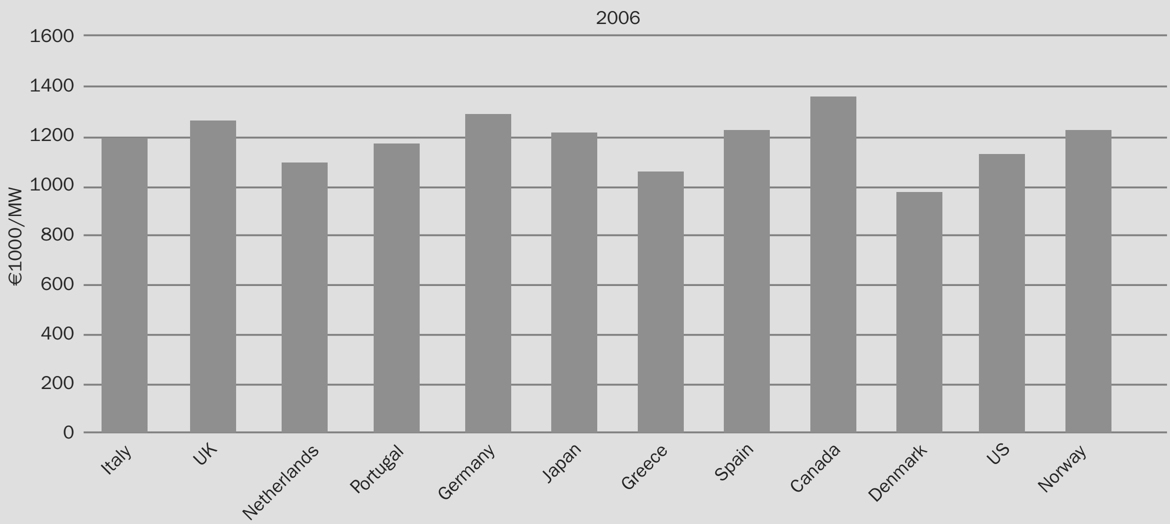
Source: Risø DTU

The total cost per kW of installed wind power capacity differs significantly between countries, as shown in Figure III.1.1. The cost per kW typically varies from around €1000/kW to €1350/kW. As shown in Figure III.1.1, the investment costs per kW were found to be lowest in Denmark, and slightly higher in Greece and The Netherlands. For the UK, Spain and Germany, the costs in the data selection were found to be around 20–30 per cent higher than in Denmark. However, it should be observed that Figure III.1.1 is based on limited data, so the results might not be entirely representative for the countries involved.

Also, for 'other costs', such as foundations and grid connection, there is considerable variation between countries, ranging from around 32 per cent of total turbine costs in Portugal to 24 per cent in Germany, 21 per cent in Italy and only 16 per cent in Denmark. However, costs vary depending on turbine size as well as the country of installation.

The typical ranges of these other cost components as a share of total additional costs are shown in Table III.1.2. In terms of variation, the single most important additional component is the cost of grid connection, which, in some cases, can account for almost half of the auxiliary costs, followed by typically lower shares for foundation cost and the cost of the electrical installation. Thus these auxiliary costs may add significant amounts to the total cost of the turbine. Cost components such as consultancy and land usually only account for a minor share of the additional costs.

Figure III.1.1: Total investment cost, including turbine, foundations and grid connection, shown for different turbine sizes and countries of installation



Source: Risø DTU; based on data from the IEA

For a number of selected countries, the turbine and auxiliary costs (foundations and grid connection) are shown in Figure III.1.2.

Table III.1.2: Cost structure for a medium-sized wind turbine

	Share of total cost (%)	Typical share of other costs (%)
Turbine (ex-works)	68–84	n/a
Foundation	1–9	20–25
Electric installation	1–9	10–15
Grid connection	2–10	35–45
Consultancy	1–3	5–10
Land	1–5	5–10
Financial costs	1–5	5–10
Road construction	1–5	5–10

Note: Based on a limited data selection from Germany, Denmark, Spain and the UK, adjusted and updated by the author.

Source: Risø DTU

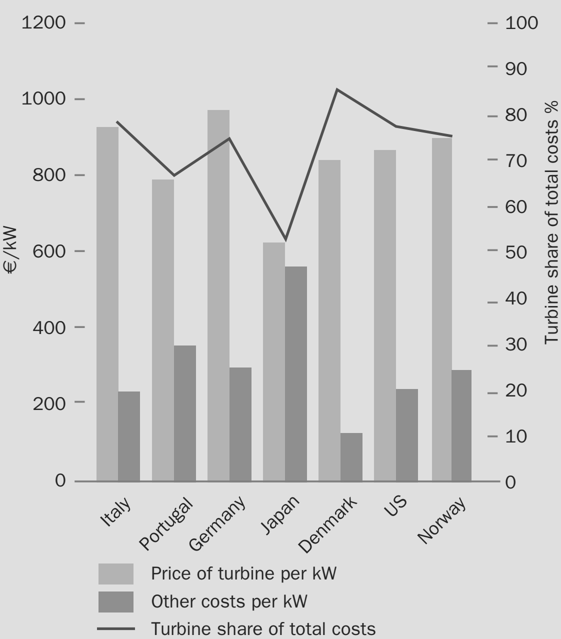
TRENDS INFLUENCING THE COSTS OF WIND POWER

In recent years, three major trends have dominated the development of grid-connected wind turbines:

1. Turbines have become larger and taller – the average size of turbines sold on the market has increased substantially.
2. The efficiency of turbine production has increased steadily.
3. In general, the investment costs per kW have decreased, although there has been a deviation from this trend in recent years.

Figure III.1.3 shows the development of the average-sized wind turbine for a number of the most important wind power countries. It can be observed that the annual average size has increased significantly over the last 10–15 years, from approximately 200 kW in 1990 to

Figure III.1.2: Price of turbine and additional costs for foundation and grid connection, calculated per kW for selected countries (left axis), including turbine share of total costs (right axis)



Note: The result for Japan may be caused by a different split of turbine investment costs and other costs, as the total adds up to almost the same level as seen for the other countries.

Source: Risø DTU

2 MW in 2007 in the UK, with Germany, Spain and the US not far behind.

As shown, there is a significant difference between some countries: in India, the average installed size in 2007 was around 1 MW, considerably lower than levels in the UK and Germany (2049 kW and 1879 kW respectively). The unstable picture for Denmark in recent years is due to the low level of turbine installations.

In 2007, turbines of the MW class (with a capacity of over 1 MW) had a market share of more than 95 per cent, leaving less than 5 per cent for the smaller machines. Within the MW segment, turbines with capacities of 2.5 MW and upwards are becoming increasingly important, even for on-land sites. In 2007, the market share of these large turbines was 6 per cent, compared to only 0.3 per cent at the end of 2003.

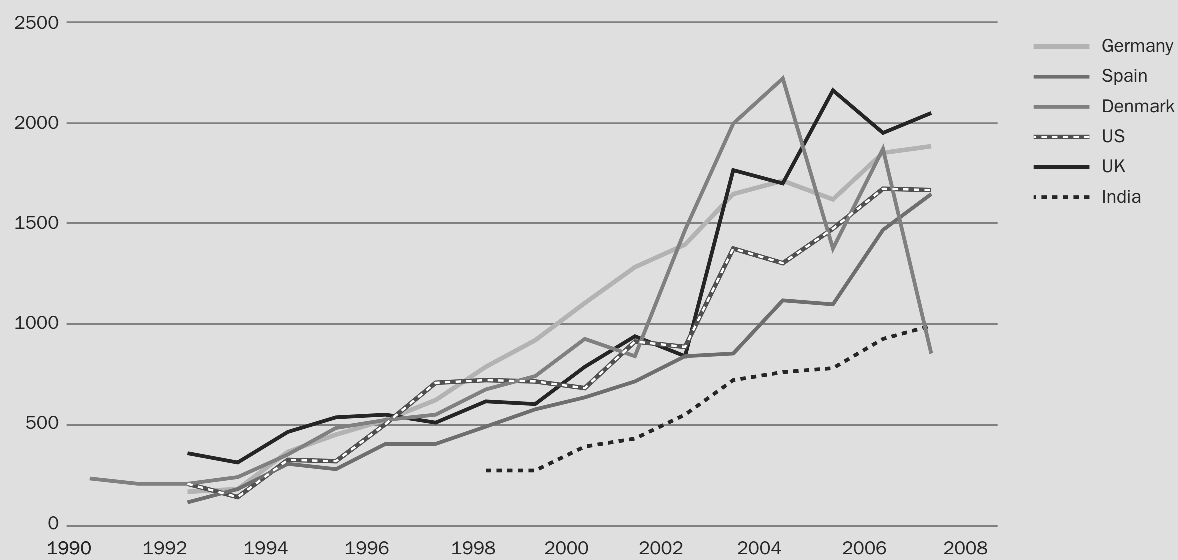
The wind regime at the chosen site, the turbine hub height and the efficiency of production determine power production from the turbines. So just increasing the height of turbines has resulted in higher power production. Similarly, the methods for measuring and evaluating the wind speed at a given site have improved substantially in recent years and thus improved the site selection for new turbines. However, the fast development of wind power capacity in countries such as Germany and Denmark implies that the best wind sites in these countries have already been taken and that new on-land turbine capacity will have to be erected at sites with a marginally lower average wind speed. The replacement of older and smaller turbines with modern versions is also becoming increasingly important, especially in countries which have been involved in wind power development for a long time, as is the case for Germany and Denmark.

The development of electricity production efficiency, owing to better equipment design, measured as annual energy production per square metre of swept rotor area (kWh/m^2) at a specific reference site, has correspondingly improved significantly in recent years. With improved equipment efficiency, improved turbine siting and higher hub height, the overall production efficiency has increased by 2–3 per cent annually over the last 15 years.

Figure III.1.4 shows how these trends have affected investment costs, exemplified by the case of Denmark, from 1989 to 2006. The data reflects turbines installed in the particular year shown (all costs are converted to 2006 prices); all costs on the right axis are calculated per square metre of swept rotor area, while those on the left axis are calculated per kW of rated capacity.

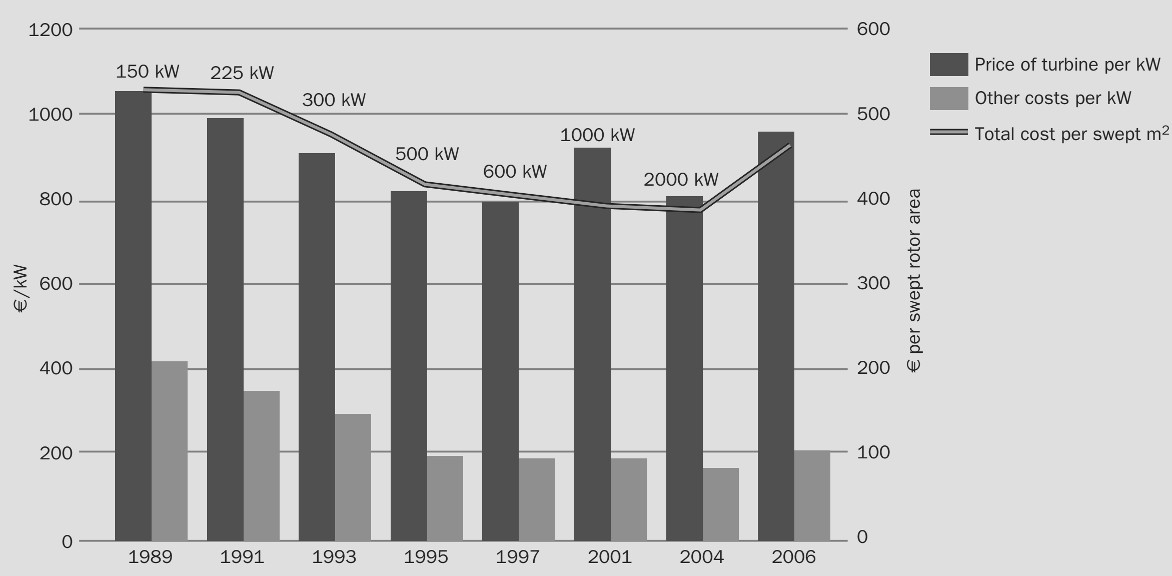
The number of square metres covered by the turbine's rotor – the swept rotor area – is a good indicator of the turbine's power production, so this measure is a relevant index for the development in costs per kWh. As shown in Figure III.1.4, there was a substantial

Figure III.1.3: Development of the average wind turbine size sold in different countries



Source: BTM-Consult

Figure III.1.4: The development of investment costs from 1989 to 2006, illustrated by the case of Denmark



Note: Right axis – investment costs divided by swept rotor area (€/m² in constant 2006-€); Left axis – wind turbine capital costs (ex-works) and other costs per kW rated power (€/kW in constant 2006-€).

decline in costs per unit of swept rotor area in the period under consideration, except during 2006. From the late 1980s until 2004, overall investments per unit of swept rotor area declined by more than 2 per cent per annum, corresponding to a total reduction in cost of almost 30 per cent over these 15 years. But this trend was broken in 2006, when total investment costs rose by approximately 20 per cent compared to 2004, mainly due to a significant increase in demand for wind turbines, combined with rising commodity prices and supply constraints.

Looking at the cost per rated capacity (per kW), the same decline is found in the period 1989 to 2004, with the exception of the 1000 kW machine in 2001. The reason for this exception is related to the size of this particular turbine: with a higher hub height and larger rotor diameter, the turbine is equipped with a slightly smaller generator, although it produces more electricity. This fact is particularly important when analysing turbines built specifically for low and medium wind areas, where the rotor diameter is considerably larger in comparison to the rated capacity. As shown in Figure III.1.4, the cost per kW installed also rose by 20 per cent in 2006 compared to 2004.

In addition, the share of other costs as a percentage of total costs has generally decreased. In 1989, almost 29 per cent of total investment costs were related to costs other than the turbine itself. By 1997, this share had declined to approximately 20 per cent. This trend towards lower auxiliary costs continues for the last turbine model shown (2000 kW), where other costs amount to approximately 18 per cent of total costs. But from 2004 to 2006 other costs rose almost in parallel with the cost of the turbine itself.

The recent increase in turbine prices is a global phenomenon which stems mainly from a strong and increasing demand for wind power in many countries, along with constraints on the supply side (not only related to turbine manufacturers, but also resulting from a deficit in sub-supplier production capacity of wind turbine components). The general price increases for newly installed wind turbines in a number of selected countries are shown in Figure III.1.5. There are significant differences between individual countries, with price increases ranging from almost none to a rise of more than 40 per cent in the US and Canada.

Operation and Maintenance Costs of Wind-Generated Power

Operation and maintenance (O&M) costs constitute a sizeable share of the total annual costs of a wind turbine. For a new turbine, O&M costs may easily make up 20–25 per cent of the total levelised cost per kWh produced over the lifetime of the turbine. If the turbine is fairly new, the share may only be 10–15 per cent, but this may increase to at least 20–35 per cent by the end of the turbine's lifetime. As a result, O&M costs are attracting greater attention, as manufacturers attempt to lower these costs significantly by developing new turbine designs that require fewer regular service visits and less turbine downtime.

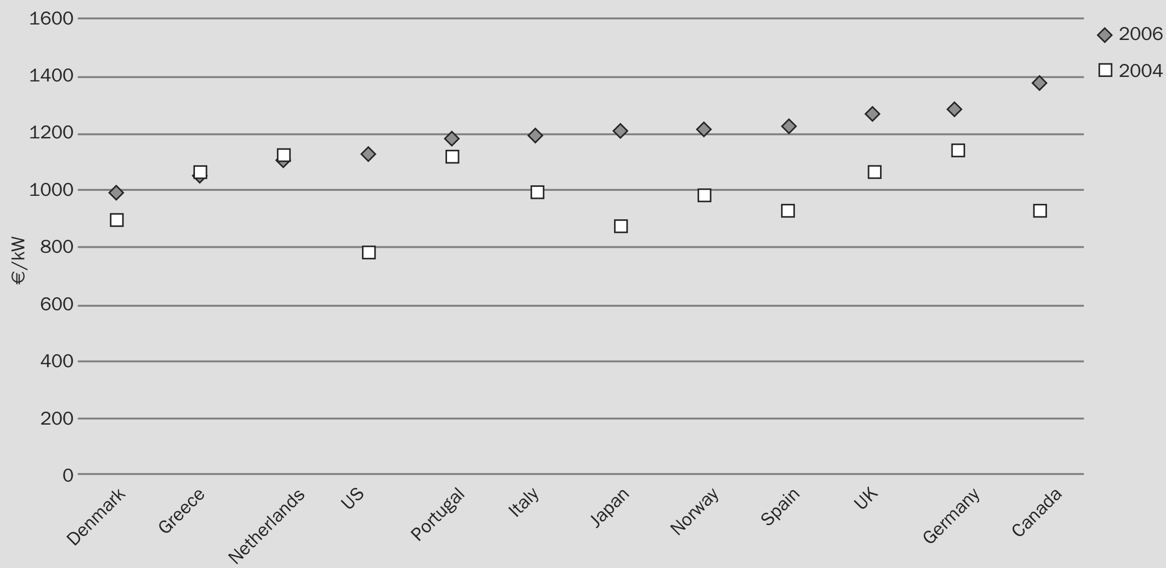
O&M costs are related to a limited number of cost components, including:

- insurance;
- regular maintenance;
- repair;
- spare parts; and
- administration.

Some of these cost components can be estimated relatively easily. For insurance and regular maintenance, it is possible to obtain standard contracts covering a considerable share of the wind turbine's total lifetime. Conversely, costs for repairs and related spare parts are much more difficult to predict. And although all cost components tend to increase as the turbine gets older, costs for repair and spare parts are particularly influenced by turbine age, starting low and increasing over time.

Due to the relative infancy of the wind energy industry, there are only a few turbines that have reached

Figure III.1.5: The increase in turbine prices from 2004 to 2006 for selected countries



Note: Preliminary data shows that prices for new turbines might continue to rise during 2007.

Source: IEA (2007b)

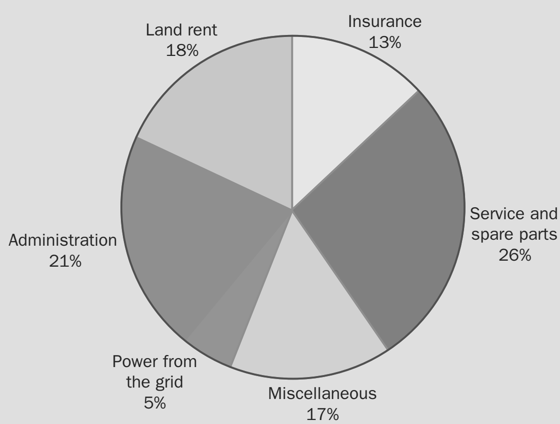
their life expectancy of 20 years. These turbines are much smaller than those currently available on the market. Estimates of O&M costs are still highly unpredictable, especially around the end of a turbine's lifetime; nevertheless a certain amount of experience can be drawn from existing older turbines.

Based on experiences in Germany, Spain, the UK and Denmark, O&M costs are generally estimated to be around 1.2 to 1.5 euro cents (c€) per kWh of wind power produced over the total lifetime of a turbine. Spanish data indicates that less than 60 per cent of this amount goes strictly to the O&M of the turbine and installations, with the rest equally distributed between labour costs and spare parts. The remaining 40 per cent is split equally between insurance, land rental[2] and overheads.

Figure III.1.6 shows how total O&M costs for the period between 1997 and 2001 were split into six different categories, based on German data from DEWI. Expenses pertaining to buying power from the grid and land rental (as in Spain) are included in the O&M costs calculated for Germany. For the first two years of its lifetime, a turbine is usually covered by the manufacturer's warranty, so in the German study O&M costs made up a small percentage (2–3 per cent) of total investment costs for these two years, corresponding to approximately 0.3–0.4c€/kWh. After six years, the total O&M costs increased, constituting slightly less than 5 per cent of total investment costs, which is equivalent to around 0.6–0.7c€/kWh. These figures are fairly similar to the O&M costs calculated for newer Danish turbines (see below).

Figure III.1.7 shows the total O&M costs resulting from a Danish study and how these are distributed between the different O&M categories, depending on the type, size and age of the turbine. For a three-year-old 600 kW machine, which was fairly well represented in the study,[3] approximately 35 per cent of total O&M costs

Figure III.1.6: Different categories of O&M costs for German turbines, averaged for 1997–2001

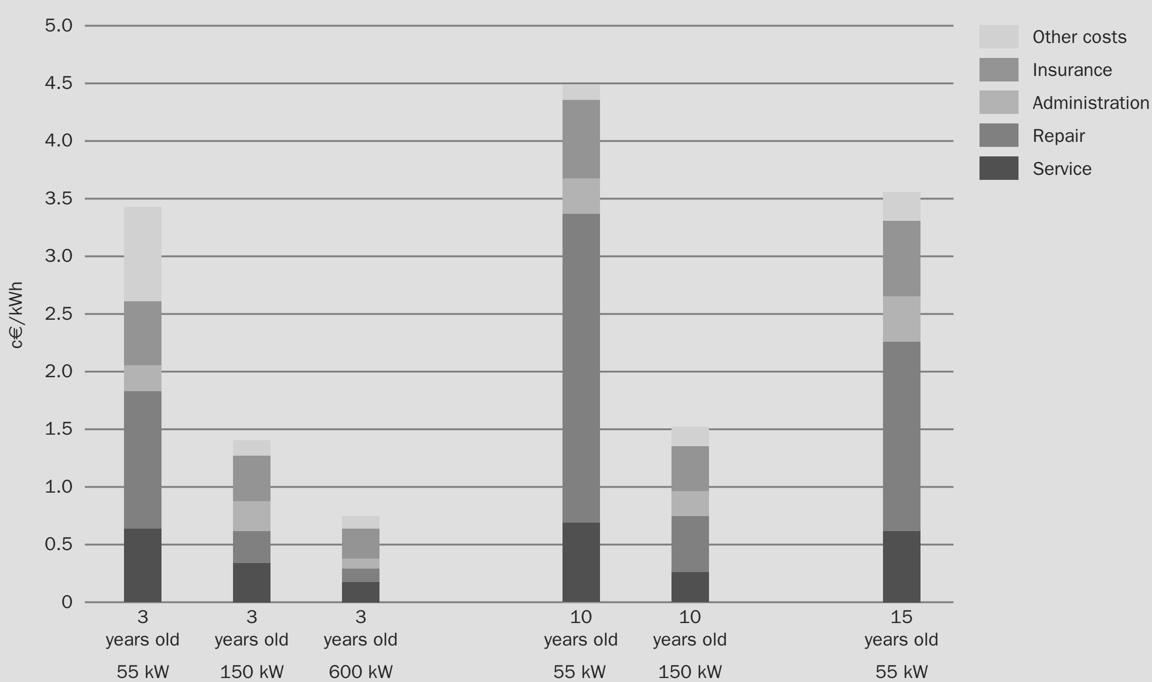


Source: DEWI

covered insurance, 28 per cent regular servicing, 11 per cent administration, 12 per cent repairs and spare parts, and 14 per cent other purposes. In general, the study revealed that expenses for insurance, regular servicing and administration were fairly stable over time, while the costs for repairs and spare parts fluctuated considerably. In most cases, other costs were of minor importance.

Figure III.1.7 also shows the trend towards lower O&M costs for new and larger machines. So for a three-year-old turbine, the O&M costs decreased from around 3.5c€/kWh for the old 55 kW turbines to less than 1c€/kWh for the newer 600 kW machines. The figures for the 150 kW turbines are similar to the O&M costs identified in the three countries mentioned above. Moreover, Figure III.1.7 shows clearly that O&M costs increase with the age of the turbine.

Figure III.1.7: O&M costs as reported for selected types and ages of turbines



Source: Jensen et al. (2002)

With regard to the future development of O&M costs, care must be taken in interpreting the results of Figure III.1.7. First, as wind turbines exhibit economies of scale in terms of declining investment costs per kW with increasing turbine capacity, similar economies of scale may exist for O&M costs. This means that a decrease in O&M costs will be related, to a certain extent, to turbine up-scaling. And second, the newer and larger turbines are better aligned with dimensioning criteria than older models, implying reduced lifetime O&M requirements. However, this may also have the adverse effect that these newer turbines will not stand up as effectively to unexpected events.

The Cost of Energy Generated by Wind Power

The total cost per kWh produced (unit cost) is calculated by discounting and levelising investment and O&M costs over the lifetime of the turbine and then dividing them by the annual electricity production. The unit cost of generation is thus calculated as an average cost over the turbine's lifetime. In reality, actual costs will be lower than the calculated average at the beginning of the turbine's life, due to low O&M costs, and will increase over the period of turbine use.

The turbine's power production is the single most important factor for the cost per unit of power generated. The profitability of a turbine depends largely on whether it is sited at a good wind location. In this section, the cost of energy produced by wind power will be calculated according to a number of basic assumptions. Due to the importance of the turbine's power production, the sensitivity analysis will be applied to this parameter. Other assumptions include the following:

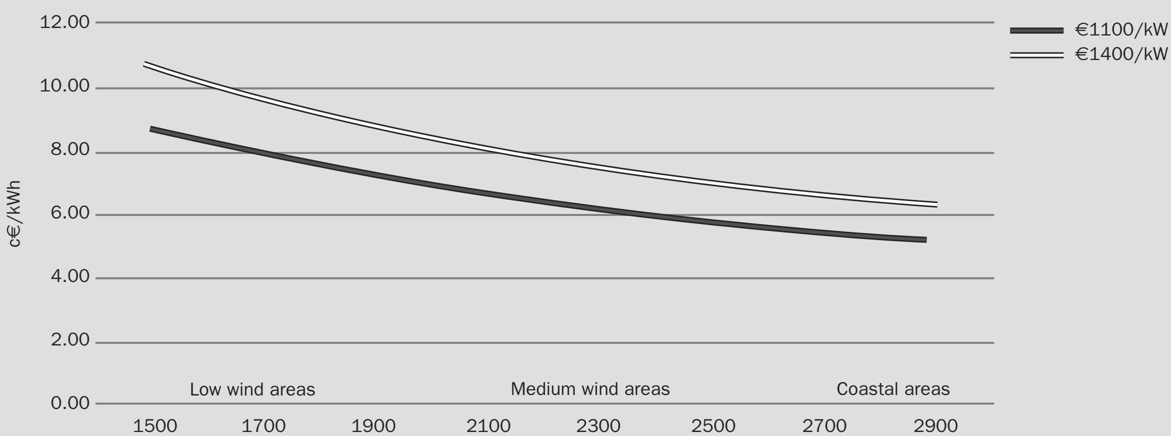
- Calculations relate to new land-based, medium-sized turbines (1.5–2 MW) that could be erected today.
- Investment costs reflect the range given in Chapter III.2 – that is, a cost of €1100–1400/kW, with an average of €1225/kW. These costs are based on data from IEA and stated in 2006 prices.
- O&M costs are assumed to be 1.45c€/kWh as an average over the lifetime of the turbine.
- The lifetime of the turbine is set at 20 years, in accordance with most technical design criteria.
- The discount rate is assumed to range from 5 to 10 per cent per annum. In the basic calculations, a discount rate of 7.5 per cent per annum is used, although a sensitivity analysis of the importance of this interest range is also performed.
- Economic analyses are carried out on a simple national economic basis. Taxes, depreciation and risk premiums are not taken into account and all calculations are based on fixed 2006 prices.

The calculated costs per kWh of wind-generated power, as a function of the wind regime at the chosen sites, are shown in Figure III.1.8. As illustrated, the costs range from approximately 7–10c€/kWh at sites with low average wind speeds to approximately 5–6.5c€/kWh at windy coastal sites, with an average of approximately 7c€/kWh at a wind site with average wind speeds.

In Europe, the good coastal positions are located mainly in the UK, Ireland, France, Denmark and Norway. Medium wind areas are mostly found inland in mid and southern Europe – in Germany, France, Spain, The Netherlands and Italy – and also in northern Europe – in Sweden, Finland and Denmark. In many cases, local conditions significantly influence the average wind speeds at a specific site, so significant fluctuations in the wind regime are to be expected even for neighbouring areas.

Approximately 75–80 per cent of total power production costs for a wind turbine are related to capital costs – that is, the costs of the turbine, foundations, electrical equipment and grid connection. Thus a wind turbine is capital-intensive compared with

Figure III.1.8: Calculated costs per kWh of wind-generated power as a function of the wind regime at the chosen site (number of full load hours)



Note: In this figure, the number of full load hours is used to represent the wind regime. Full load hours are calculated as the turbine's average annual production divided by its rated power. The higher the number of full load hours, the higher the wind turbine's production at the chosen site.

Source: Risø DTU

conventional fossil fuel-fired technologies, such as natural gas power plants, where as much as 40–60 per cent of total costs are related to fuel and O&M costs. For this reason, the costs of capital (discount or interest rate) are an important factor for the cost of wind-generated power, a factor which varies considerably between the EU member countries.

In Figure III.1.9, the costs per kWh of wind-produced power are shown as a function of the wind regime and the discount rate (which varies between 5 and 10 per cent per annum).

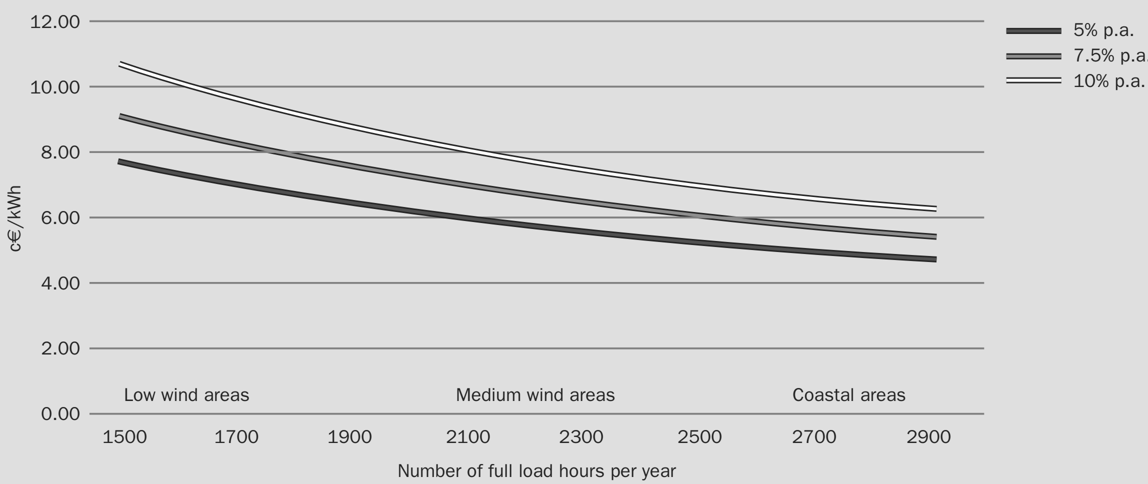
As illustrated in Figure III.1.9, the costs range between around 6 and 8c€/kWh at medium wind positions, indicating that a doubling of the interest rate induces an increase in production costs of 2c€/kWh. In low wind areas, the costs are significantly higher, at around 8–11c€/kWh, while the production costs range between 5 and 7c€/kWh in coastal areas.

Development of the Cost of Wind-Generated Power

The rapid European and global development of wind power capacity has had a strong influence on the cost of wind power over the last 20 years. To illustrate the trend towards lower production costs of wind-generated power, a case that shows the production costs for different sizes and models of turbines is presented in Figure III.1.10.

Figure III.1.10 shows the calculated unit cost for different sizes of turbine, based on the same assumptions used in the previous section: a 20-year lifetime is assumed for all turbines in the analysis and a real discount rate of 7.5 per cent per annum is used. All costs are converted into constant 2006 prices. Turbine electricity production is estimated for two wind regimes – a coastal and an inland medium wind position.

Figure III.1.9: The costs of wind-produced power as a function of wind speed (number of full load hours) and discount rate; the installed cost of wind turbines is assumed to be €1225/kW



Source: Risø DTU

The starting point for the analysis is the 95 kW machine, which was installed mainly in Denmark during the mid-1980s. This is followed by successively newer turbines (150 kW and 225 kW), ending with the 2000 kW turbine, which was typically installed from around 2003 onwards. It should be noted that wind turbine manufacturers generally expect the production cost of wind power to decline by 3–5 per cent for each new turbine generation they add to their product portfolio. The calculations are performed for the total lifetime (20 years) of the turbines; calculations for the old turbines are based on track records of more than 15 years (average figures), while newer turbines may have a track record of only a few years, so the newer the turbine, the less accurate the calculations.

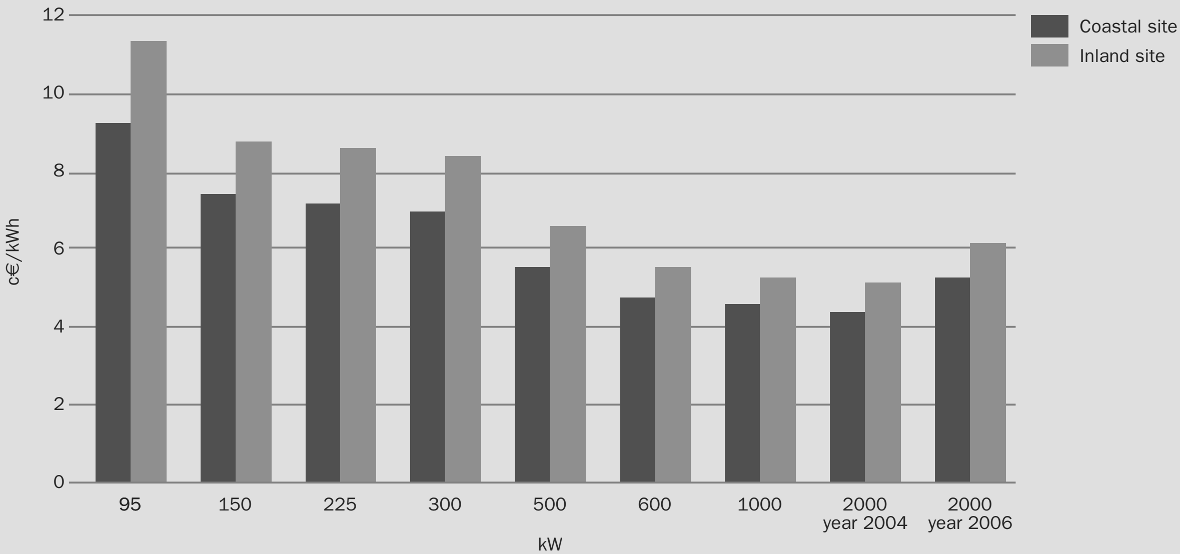
The economic consequences of the trend towards larger turbines and improved cost-effectiveness are clearly shown in Figure III.1.10. For a coastal position, for example, the average cost has decreased from around 9.2c€/kWh for the 95 kW turbine (mainly installed in the mid-1980s) to around 5.3c€/kWh for a fairly new 2000 kW machine, an improvement of more than 40 per cent over 20 years (constant 2006 prices).

Future Evolution of the Costs of Wind-Generated Power

In this section, the future development of the economics of wind power is illustrated by the use of the experience curve methodology. The experience curve approach was developed in the 1970s by the Boston Consulting Group; it relates the cumulative quantitative development of a product to the development of the specific costs (Johnson, 1984). Thus, if the cumulative sale of a product doubles, the estimated learning rate gives the achieved reduction in specific product costs.

The experience curve is not a forecasting tool based on estimated relationships. It merely shows the development as it would be if existing trends continue.

Figure III.1.10: Total wind energy costs per unit of electricity produced, by turbine size (c€/kWh, constant 2006 prices)



Source: Risø DTU

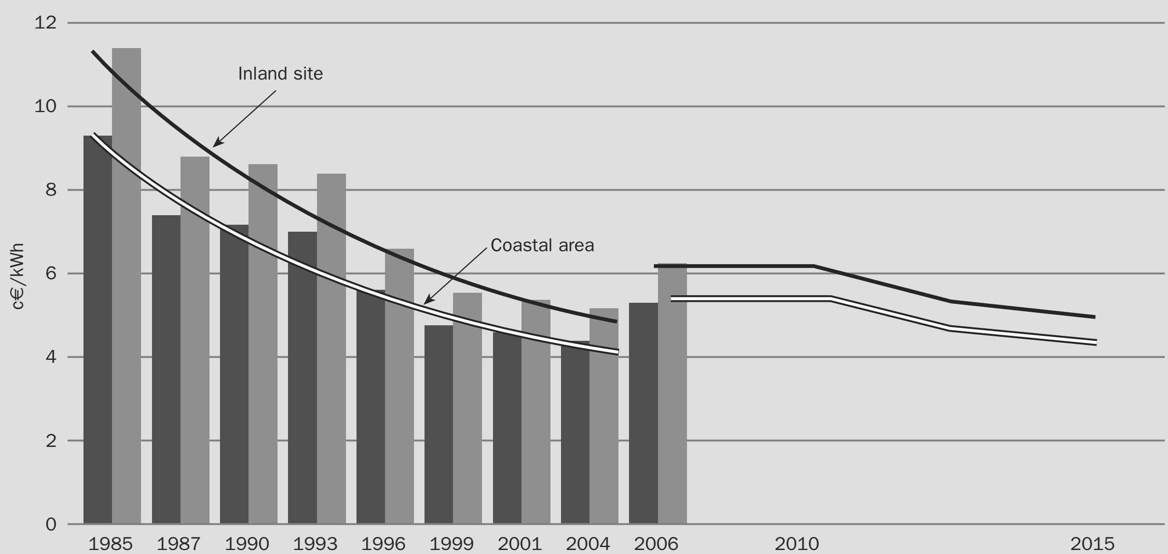
It converts the effect of mass production into an effect upon production costs, without taking other causal relationships into account. Thus changes in market development and/or technological breakthroughs within the field may change the picture considerably, as would fluctuations in commodity prices such as those for steel and copper.

Different experience curves have been estimated[4] for a number of projects. Unfortunately, different specifications were used, which means that not all of these projects can be directly compared. To obtain the full value of the experiences gained, the reduction in price of the turbine (€/kW) should be taken into account, as well as improvements in the efficiency of the turbine's production (which requires the use of an energy specification (€/kWh); see Neij et al., 2003). Thus, using the specific costs of energy as a basis (costs per kWh produced), the estimated progress ratios range from 0.83 to 0.91, corresponding to learning rates of 0.17 to 0.09. So when the total installed capacity of wind power doubles, the costs per kWh produced for new turbines goes down by between 9 and 17 per cent. In this way, both the efficiency improvements and embodied and disembodied cost reductions are taken into account in the analysis.

Wind power capacity has developed very rapidly in recent years, on average by 25 to 30 per cent per year over the last ten years. At present, the total wind power capacity doubles approximately every three to four years. Figure III.1.11 shows the consequences for wind power production costs, based on the following assumptions:

- The present price-relation should be retained until 2010. The reason why no price reductions are foreseen in this period is due to a persistently high demand for new wind turbine capacity and sub-supplier constraints in the delivery of turbine components.

Figure III.1.11: Using experience curves to illustrate the future development of wind turbine economics until 2015



Note: Costs are illustrated for an average 2 MW turbine installed at either an inland site or a coastal site.

Source: Risø DTU

- From 2010 until 2015, a learning rate of 10 per cent is assumed, implying that each time the total installed capacity doubles, the costs per kWh of wind generated power decrease by 10 per cent.
- The growth rate of installed capacity is assumed to double cumulative installations every three years.

The curve illustrates cost development in Denmark, which is a fairly cheap wind power country. Thus the starting point for the development is a cost of wind power of around 6.1c€/kWh for an average 2 MW turbine sited at a medium wind regime area (average wind speed of 6.3 m/s at a hub height of 50 m). The development for a coastal position is also shown.

At present, the production costs for a 2 MW wind turbine installed in an area with a medium wind speed (inland position) are around 6.1c€/kWh of wind-produced power. If sited in a coastal location, the current costs are around 5.3c€/kWh. If a doubling time of total installed capacity of three years is assumed, in 2015 the cost interval would be approximately 4.3 to 5.0c€/kWh for a coastal and inland site respectively. A doubling time of five years would imply a cost interval, in 2015, of 4.8 to 5.5c€/kWh. As mentioned, Denmark is a fairly cheap wind power country; for more expensive countries, the cost of wind power produced would increase by 1–2c€/kWh.

III.2 OFFSHORE DEVELOPMENTS

Development and Investment Costs of Offshore Wind Power

Offshore wind only accounts for a small amount of the total installed wind power capacity in the world – approximately 1 per cent. The development of offshore wind has mainly been in northern European countries, around the North Sea and the Baltic Sea, where about 20 projects have been implemented. At the end of 2007, almost 1100 MW of capacity was located offshore.

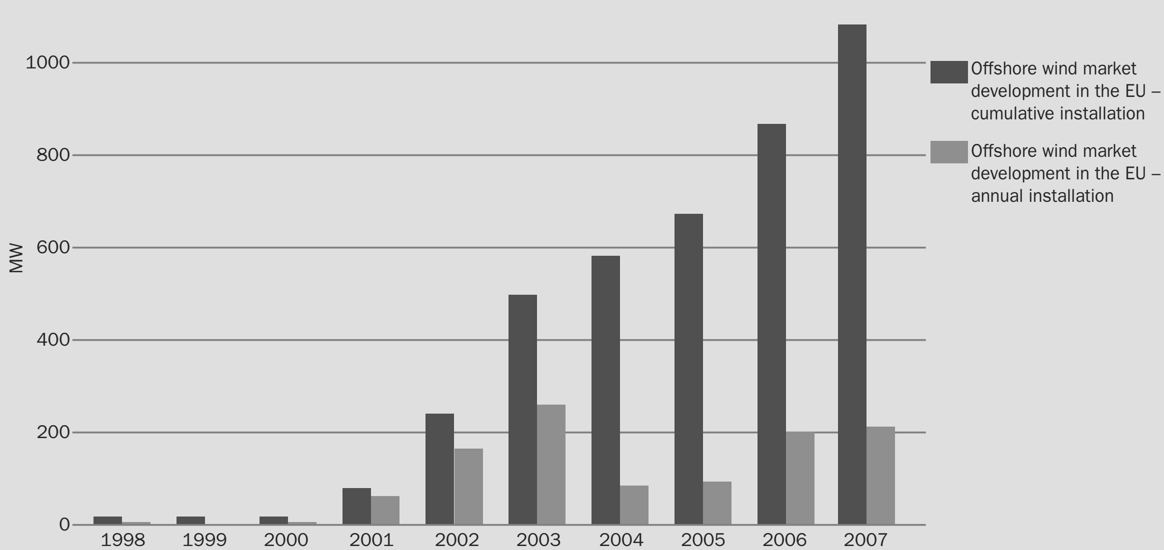
Five countries have operating offshore wind farms: Denmark, Ireland, The Netherlands, Sweden and the UK, as shown in Table III.2.1. In 2007, the Swedish offshore wind farm Lillgrunden, with a rated capacity of 110 MW, was installed. Most of the capacity has been installed in relatively shallow waters (under 20 m deep) no more than 20 km from the coast in order to minimise the extra costs of foundations and sea cables.

Offshore wind is still around 50 per cent more expensive than onshore wind. However, due to the expected benefits of more wind and the lower visual impact of the larger turbines, several countries now have very ambitious goals concerning offshore wind.

The total capacity is still limited, but growth rates are high. Offshore wind farms are installed in large units – often 100–200 MW – and two new installed wind farms per year will result in future growth rates of between 20 and 40 per cent. Presently, higher costs and temporary capacity problems in the manufacturing stages, as well as difficulties with the availability of installation vessels, cause some delays, but even so, several projects in the UK and Denmark will be finished within the next three years, as can be seen in Tables III.2.2–III.2.6.

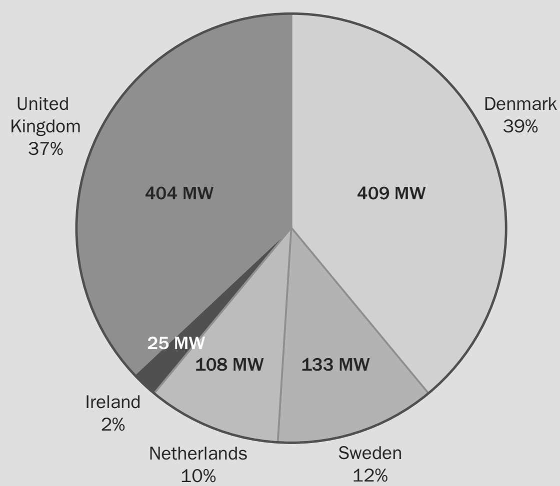
Offshore costs depend largely on weather and wave conditions, water depth and distance from the coast. The most detailed cost information on recent offshore installations comes from the UK, where 90 MW in

Figure III.2.1: Development of offshore wind power in the EU, 1998–2007



Source: EWEA

Figure III.2.2: Total offshore wind power installed by the end of 2007



Source: EWEA

2006 and 100 MW in 2007 were added, and from Sweden with the installation of Lillgrunden in 2007.

Table III.2.7 gives information on some of the recently established offshore wind farms. As shown, the chosen turbine size for offshore wind farms ranges from 2 to 3.6 MW, with the newer wind farms being equipped with the larger turbines. The size of the wind farms also vary substantially, from the fairly small Samsø wind farm of 23 MW to Robin Rigg, the world's largest offshore wind farm, with a rated capacity of 180 MW. Investment costs per MW range from a low of €1.2 million/MW (Middelgrunden) to €2.7 million/MW (Robin Rigg) (Figure III.2.3).

The higher offshore capital costs are due to the larger structures and the complex logistics of installing the towers. The costs of offshore foundations, construction, installations and grid connection are significantly higher than for onshore. For example, offshore turbines are generally 20 per cent more expensive and towers and foundations cost more than 2.5 times the price of those for a similar onshore project.

In general, the costs of offshore capacity have increased in recent years, as is the case for land-based turbines, and these increases are only partly reflected in the costs shown in Figure III.2.3. As a result, the average costs of future offshore farms are expected to be higher. On average, investment costs for a new offshore wind farm are expected be in the range of €2.0–2.2 million/MW for a near-shore, shallow-water facility.

To illustrate the economics of offshore wind turbines in more detail, the two largest Danish offshore wind farms can be taken as examples. The Horns Rev project, located approximately 15 km off the west coast of Jutland (west of Esbjerg), was finished in 2002. It is equipped with 80 machines of 2 MW, with a total capacity of 160 MW. The Nysted offshore wind farm is located south of the isle of Lolland. It consists of 72 turbines of 2.3 MW and has a total capacity of 165 MW. Both wind farms have their own on-site transformer stations,

Table III.2.1: Installed offshore capacity in offshore wind countries

Country	MW installed in 2006	Accumulated MW, end 2006	MW installed in 2007	Accumulated MW, end 2007
Denmark	0	409	0	409
Ireland	0	25	0	25
The Netherlands	108	108	0	108
Sweden	0	23	110	133
UK	90	304	100	404
Total global	198	869	210	1079

Source: EWEA

Table III.2.2: Operating and planned offshore wind farms in the UK

Project	Location	Region	Capacity (MW)	No of turbines	Water depth (m)	Distance to shore (km)	Online
In operation							
Barrow	7 km from Walney Island	Off England	90	30	>15	7	2006
Beatrice	Beatrice Oilfield, Moray Firth	Off Scotland	10	2	>40	unknown	2007
Blyth Offshore	1 km from Blyth Harbour	Off England	3.8	2	6	1	2000
Burbo Bank	5.2 km from Crosby	Off England	90	25	10	5.2	2007
Inner Dowsing	5.2 km from Ingoldmells	Off England	90	30	10	5.2	2008
Kentish Flats	8.5 km from Whitstable	Off England	90	30	5	8.5	2005
Lynn	5.2 km from Skegness	Off England	97	30	10	5.2	2008
North Hoyle	7.5 km from Prestatyn and Rhyl	Off Wales/England	60	30	5–12	7.5	2003
Scroby Sands	3 km NE of Great Yarmouth	Off England	60	30	2–10	3	2004
			403.8				
Under construction							
Greater Gabbard phase 1	Off Felixstowe/Clacton-on-Sea	Off England	300	-	-	-	2010
Greater Gabbard phase 2	Off Felixstowe/Clacton-on-Sea	Off England	200	-	-	-	2011
Ormonde	Off Walney Island	Off England	150	30	20	11	2010
Rhyl Flats	8 km from Abergele	Off Wales	90	25	8	8	2009
Solway Firth/ Robin Rigg A	9.5 km from Maryport/8.5 km off Rock Cliffe	Off England/ Scotland	90	30	>5	9.5	2010
Solway Firth/ Robin Rigg B	9.5 km from Maryport/8.5 km off Rock Cliffe	Off England/ Scotland	90	30	>5	9.5	2010
Thanet	Foreness Point, Margate	Off England	300	100	20–25	7–8.5	2010

Source: EWEA

Table III.2.3: Operating and planned offshore wind farms in The Netherlands

Project	Location	Capacity (MW)	No of turbines	Water depth (m)	Distance to shore (km)	Online
In operation						
Offshore Wind Farm Egmond aan Zee (OWEZ)	Egmond aan Zee	108	36	17–23	8–12	2006
Lely	Medemblik, Ijsselmeer (inland lake)	2	4	7.5	0.75	1994
Irene Vorrink (Dronten)	Dronten, Ijsselmeer (inland freshwater lake), to the outside of the dyke	16.8	28	2	0.03	1996
Princess Amalia	Ijmuiden	120	60	19–24	> 23	2008

Source: EWEA

Table III.2.4: Operating and planned offshore wind farms in Denmark

Project	Location	Capacity (MW)	No of turbines	Water depth (m)	Distance to shore (km)	Online
In operation						
Vindeby	Blæsenborg Odde, NW off Vindeby, Lolland	4.95	11	2.5–5	2.5	1991
TunøKnob	off Aarhus, Kattegat Sea	5	10	0.8–4	6	1995
Middelgrunden	Oresund, east of Copenhagen harbour	40	20	5–10	2–3	2001
Horns Rev I	Blåvandshuk, Baltic Sea	160	80	6–14	14–17	2002
Nysted Havmøllepark	Rødsand, Lolland	165.6	72	6–10	6–10	2003
Samsø	Paludans Flak, South of Samsø	23	4	11–18	3.5	2003
Frederikshavn	Frederikshavn Harbour	10.6	4	3	0.8	2003
Rønland I	Lim fjord, off Rønland peninsula, in the Nissum Bredning, off NW Jutland	17.2	8	3		2003
		426.35				
Under construction						
Avedøre	Off Avedøre	7.2	2	2	0.025	2009
Frederikshavn (test site)	Frederikshavn Harbour	12	2	15–20	4.5	2010
Rødsand 2	Off Rødsand, Lolland	200	89	5–15	23	2010
Sprøgø	North of Sprøgø	21	7	6–16	0.5	2009
Horns Rev II	Blåvandshuk, Baltic Sea (10 km west of Horns Rev)	209	91	9–17	30	2010

Source: EWEA

Table III.2.5: Operating and planned offshore wind farms in Sweden

Project	Location	Capacity (MW)	No of turbines	Water depth (m)	Distance to shore (km)	Online
In operation						
Bockstigen	Gotland	2.8	5	6–8	3	1998
Utgrunden I	Kalmarsund	10.5	7	4–10	7	2001
Yttre Stengrund	Kalmarsund	10.0	5	8–12	4	2002
Lillgrund	Malmö	110.0	48	2.5–9	10	2007
		133.25				
Under construction						
Gässlingegrund	Vänern	30	10	4–10	4	2009

Source: EWEA

Table III.2.6: Operating offshore wind farms in Ireland

Project	Location	Capacity (MW)	No of turbines	Water depth (m)	Distance to shore (km)	Online
Arklow Bank	Off Arklow, Co Wicklow	25.2	7	15	10	2004

Source: EWEA

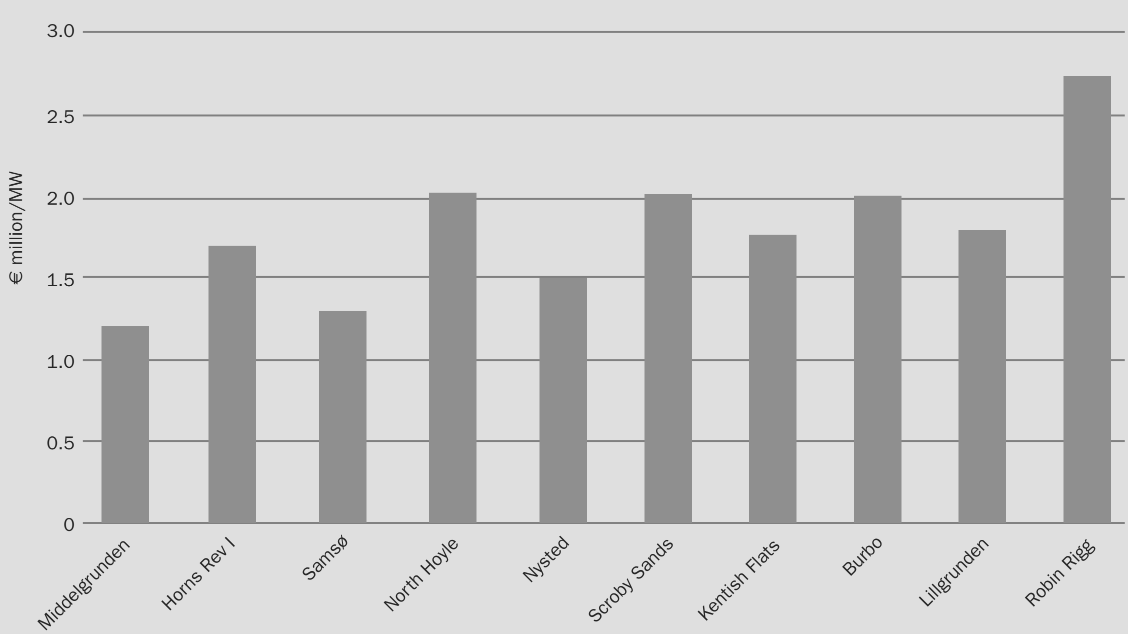
Table III.2.7: Key information on recent offshore wind farms

	In operation	No of turbines	Turbine size (MW)	Total capacity (MW)	Investment costs (€ million)
Middelgrunden (DK)	2001	20	2	40	47
Horns Rev I (DK)	2002	80	2	160	272
Samsø (DK)	2003	10	2.3	23	30
North Hoyle (UK)	2003	30	2	60	121
Nysted (DK)	2004	72	2.3	165	248
Scroby Sands (UK)	2004	30	2	60	121
Kentish Flats (UK)	2005	30	3	90	159
Barrows (UK)	2006	30	3	90	–
Burbo Bank (UK)	2007	24	3.6	90	181
Lillgrunden (S)	2007	48	2.3	110	197
Robin Rigg (UK)		60	3	180	492

Note: Robin Rigg is under construction.

Source: Risø DTU

Figure III.2.3: Investments in offshore wind farms, €million/MW (current prices)



Source: Risø DTU

Table III.2.8: Average investment costs per MW related to offshore wind farms in Horns Rev and Nysted

	Investments (€1000/MW)	Share (%)
Turbines ex-works, including transport and erection	815	49
Transformer station and main cable to coast	270	16
Internal grid between turbines	85	5
Foundations	350	21
Design and project management	100	6
Environmental analysis	50	3
Miscellaneous	10	<1
Total	1680	~100

Note: Exchange rate EUR1 = DKK7.45.

Source: Risø DTU

which are connected to the high voltage grid at the coast via transmission cables. The farms are operated from onshore control stations, so staff are not required at the sites. The average investment costs related to these two farms are shown in Table III.2.8.

In Denmark, all of the cost components above are covered by the investors, except for the costs of the transformer station and the main transmission cable to the coast, which are covered by TSOs in the respective areas. The total costs of each of the two offshore farms are around €260 million.

In comparison to land-based turbines, the main differences in the cost structure are related to two issues:

1. Foundations are considerably more expensive for offshore turbines. The costs depend on both the sea depth and the type of foundation being built (at Horns Rev monopiles were used, while the turbines at Nysted are erected on concrete gravity foundations). For a conventional turbine situated on land, the foundations' share of the total cost is normally around 5–9 per cent, while the average of the two projects mentioned above is 21 per cent (see Table III.2.8), and thus considerably more expensive. However, since considerable experience will be gained through these two wind farms, a further optimisation of foundations can be expected in future projects.
2. Transformer stations and sea transmission cables increase costs. Connections between turbines and the centrally located transformer station, and from there to the coast, generate additional costs. For the Horns Rev and Nysted wind farms, the average cost share for the transformer station and sea transmission cables is 21 per cent (see Table III.2.8), of which a small proportion (5 per cent) goes on the internal grid between turbines.

Finally, a number of environmental analyses, including an environmental impact investigation (EIA) and graphic visualising of the wind farms, as well as additional research and development, were carried out. The average cost share for these analyses accounted for approximately 6 per cent of total costs, but part of these costs are related to the pilot character of these projects and are not expected to be repeated for future offshore wind farm installations.

The Cost of Energy Generated by Offshore Wind Power

Although the costs are higher for offshore wind farms, they are somewhat offset by a higher total electricity production from the turbines, due to higher offshore wind speeds. An on-land installation normally has around 2000–2300 full load hours per year, while for a typical offshore installation this figure reaches more

Table III.2.9: Assumptions used for economic calculations

	In operation	Capacity (MW)	€million/MW	Full load hours per year
Middelgrunden	2001	40	1.2	2500
Horns Rev I	2002	160	1.7	4200
Samsø	2003	23	1.3	3100
North Hoyle	2003	60	2.0	3600
Nysted	2004	165	1.5	3700
Scroby Sands	2004	60	2.0	3500
Kentish Flats	2005	90	1.8	3100
Burbo	2007	90	2.0	3550
Lillgrunden	2007	110	1.8	3000
Robin Rigg		180	2.7	3600

Note: Robin Rigg is under construction.

Source: Risø DTU

than 3000 full load hours per year. The investment and production assumptions used to calculate the costs per kWh are given in Table III.2.9.

In addition, the following economic assumptions are made:

- Over the lifetime of the wind farm, annual O&M costs are assumed to be €16 /MWh, except for Middelgrunden, where these costs based on existing accounts are assumed to be €12 /MWh for the entire lifetime.
- The number of full load hours is given for a normal wind year and corrected for shadow effects in the farm, as well as unavailability and losses in transmission to the coast.
- The balancing of the power production from the turbines is normally the responsibility of the farm owner. According to previous Danish experience, balancing requires an equivalent cost of around €3/MWh.[5] However, balancing costs are also uncertain and may differ substantially between countries.
- The economic analyses are carried out on a simple national economic basis, using a discount rate of 7.5 per cent per annum, over the assumed lifetime of 20 years. Taxes, depreciation, profit and risk premiums are not taken into account.

Figure III.2.4 shows the total calculated costs per MWh for the wind farms listed in Table III.2.9.

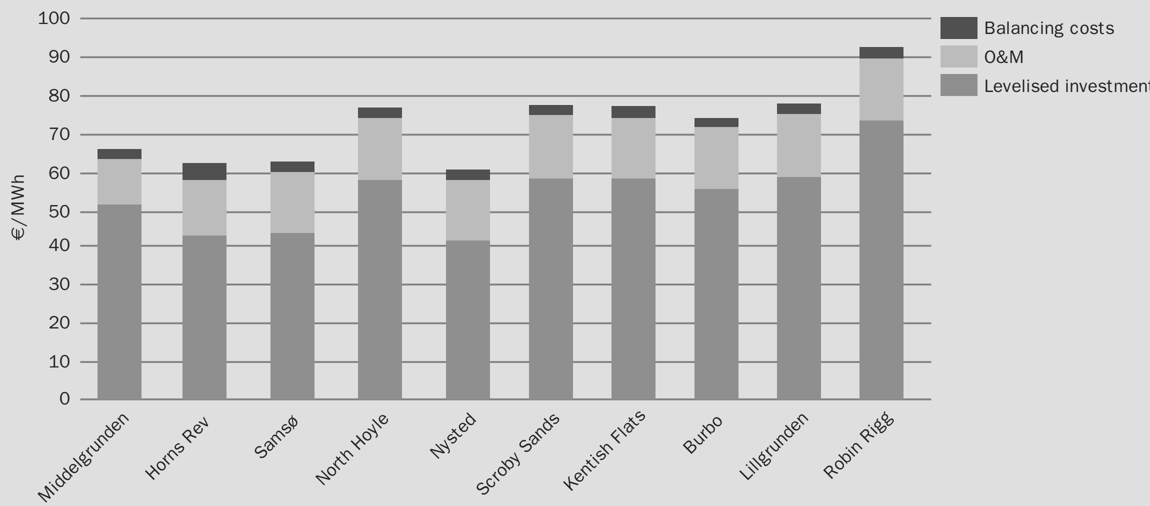
It can be seen that total production costs differ significantly between the illustrated wind farms, with Horns Rev, Samsø and Nysted being among the cheapest and Robin Rigg in the UK the most expensive. Differences can be related partly to the depth of the sea and distance to the shore and partly to increased investment costs in recent years. O&M costs are assumed to be at the same level for all wind farms (except Middelgrunden) and are subject to considerable uncertainty.

Costs are calculated on a simple national economic basis, and are not those of a private investor. Private investors have higher financial costs and require a risk premium and profit. So the amount a private investor would add on top of the simple costs would depend, to a large extent, on the perceived technological and political risks of establishing the offshore farm and on the competition between manufacturers and developers.

Development of the Cost of Offshore Wind Power up to 2015

Until 2004, the cost of wind turbines generally followed the development of a medium-term cost

Figure III.2.4: Calculated production cost for selected offshore wind farms, including balancing costs (2006 prices)



Source: Risø DTU

reduction curve (learning curve), showing a learning rate of approximately 10 per cent – in other words, each time wind power capacity doubled, the cost went down by approximately 10 per cent per MW installed. This decreasing cost trend changed in 2004–2006, when the price of wind power in general increased by approximately 20–25 per cent. This was caused mainly by the increasing costs of materials and a strong demand for wind capacity, which implied the scarcity of wind power manufacturing capacity and sub-supplier capacity for manufacturing turbine components.

A similar price increase can be observed for offshore wind power, although the fairly small number of finished projects, as well as a large spread in investment costs, make it difficult to identify the price level for offshore turbines accurately. On average, the expected investment costs for a new offshore wind farm are currently in the range of €2.0–2.2 million/MW.

In the following section, the medium-term cost development of offshore wind power is estimated using the learning curve methodology. However, it should be noted that considerable uncertainty is related to the use of learning curves, even for the medium term, and results should be used with caution.

The medium-term cost predictions for offshore wind power are shown in Table III.2.10 under the following conditions:

- The existing manufacturing capacity constraints for wind turbines will continue until 2010. Although there will be a gradual expansion of industrial capacity for wind power, a prolonged increase in demand will continue to strain the manufacturing capacity. Increasing competition among wind turbine manufacturers and sub-suppliers, resulting in unit reduction costs in the industry, will not occur before 2011.
- The total capacity development of wind power is assumed to be the main driving factor for the cost

Table III.2.10: Estimates for cost development of offshore wind turbines until 2015 (constant 2006 euros)

	Investment costs, €million/MW			O&M	Capacity factor
	Min	Average	Max	€/MWh	%
2006	1.8	2.1	2.4	16	37.5
2015	1.55	1.81	2.06	13	37.5

development of offshore turbines, since most of the turbine costs are related to the general wind power industry development. The growth rate of installed capacity is assumed to double cumulative installations every three years.

- For the period between 1985 and 2004, a learning rate of approximately 10 per cent was estimated (Neij et al., 2003). In 2011, this learning rate is again expected to be achieved by the industry and remain until at least 2015.

Given these assumptions, minimum, average and maximum cost scenarios are reported in Table III.2.10.

As shown in Table III.2.10, the average cost of offshore wind capacity is expected to decrease from €2.1 million/MW in 2006 to €1.81 million/MW in 2015, or by approximately 15 per cent. There will still be a considerable spread of costs, from €1.55 million/MW to €2.06 million/MW. A capacity factor of a constant 37.5 per cent (corresponding to an approximate number of full load hours of 3300) is expected for the whole period. This covers increased production from newer and larger turbines, moderated by sites with lower wind regimes and a greater distance to shore, which increase losses in transmission of power.

A study carried out in the UK (IEA, 2006) has estimated the future costs of offshore wind generation and the potential for cost reductions. The cost of raw materials, especially steel, which accounts for about 90 per cent of the turbine, was identified as the primary cost driver. The report emphasised that major savings can be achieved if turbines are made of lighter, more reliable materials and if major components are developed to be more fatigue-resistant. A model based on 2006 costs predicted that costs would rise from approximately £1.6 million/MW to approximately £1.75 million/MW (€2.37 to 2.6 million/MW) in 2011 before falling by around 20 per cent of the total cost by 2020.

III.3 PROJECT FINANCING

Over the last couple of decades, the vast majority of commercial wind farms have been funded through project finance. Project finance is essentially a project loan, backed by the cash flow of the specific project. The predictable nature of cash flows from a wind farm means they are highly suited to this type of investment mechanism.

Recently, as an increasing number of large companies have become involved in the sector, there has been a move towards balance sheet funding, mainly for construction. This means that the owner of the project provides all the necessary financing for the project, and the project's assets and liabilities are all directly accounted for at company level. At a later date, these larger companies will sometimes group multiple balance sheet projects in a single portfolio and arrange for a loan to cover the entire portfolio, as it is easier to raise a loan for the portfolio than for each individual project.

The structured finance markets (such as bond markets) in Europe and North America have also been used, but to a more limited extent than traditional project finance transactions. Such deals are like a loan transaction insomuch as they provide the project with an investment, in return for capital repayment and interest. However, the way in which transactions are set up is quite different to a traditional loan. Different types of funding for renewable energy have emerged in recent years in the structured debt market, which has significantly increased the liquidity in the sector.

Typical structures and transaction terms are discussed in more detail in this chapter.

Traditional Methods

WHAT IS PROJECT FINANCE?

Project finance is the term used to describe a structure in which the only security for a loan is the project itself. In other words, the owner of the project company is not personally, or corporately, liable for the loan. In a project finance deal, no guarantee is given that the loan will be repaid; however, if the loan is not repaid, the investor can seize the project and run or sell it in order to extract cash.

This process as rather like a giant property mortgage, since if a homeowner does not repay the mortgage on time, the house may be repossessed and sold by the lender. Therefore, the financing of a project requires careful consideration of all the different aspects, as well as the associated legal and commercial arrangements. Before investment, any project finance lender will want to know if there is any risk that repayment will not be made over the loan term.

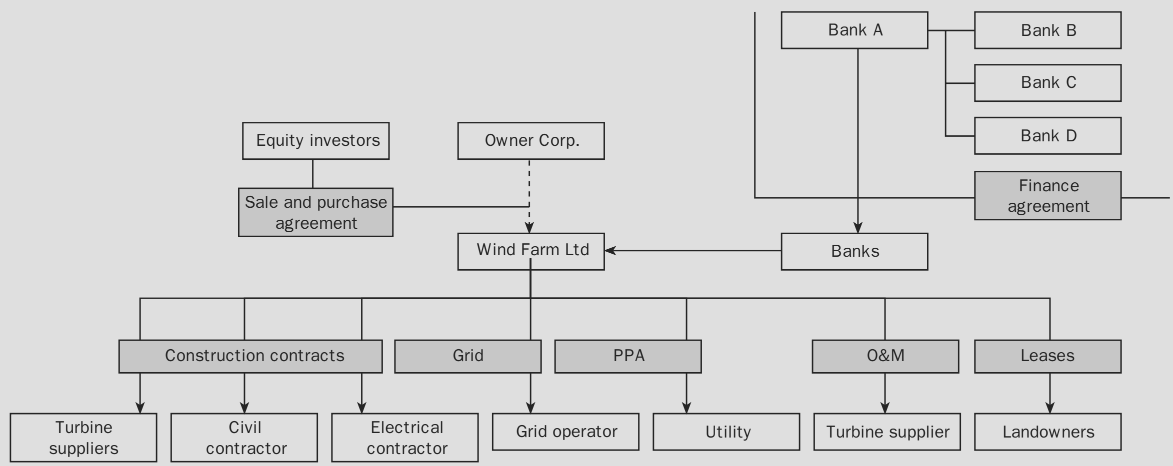
DEAL STRUCTURE

A typical simple project finance deal will be arranged through a special purpose vehicle (SPV) company. The SPV is called 'Wind Farm Ltd' in Figure III.3.1. This would be a separate legal entity which may be owned by one company, consisting of several separate entities or a joint venture.

One bank may act alone if the project is very small, but will usually arrange a lending syndicate – this means that a group of banks will join together to provide the finance, usually with one bank as the 'lead arranger' of the deal. This is shown in Figure III.3.1, where Bank A syndicates the loan to Banks B, C and D.

A considerable amount of work is carried out before the loan is agreed, to check that the project is well planned and that it can actually make the necessary repayments by the required date. This process is called 'due diligence', and there is usually separate commercial, technical and legal due diligence carried out on behalf of the bank. The investors will make careful consideration of technical, financial and political risks, as well as considering how investment in a project fits in with the bank's own investment strategy.

Figure III.3.1: Typical wind farm finance structure



Source: Garrard Hassan

TYPICAL DEAL PARAMETERS

Generally, a bank will not lend 100 per cent of the project value and will expect to see a cash contribution from the borrower – this is usually referred to as 'equity'. It is typical to see 25–30 per cent equity and 70–75 per cent loan (money provided by the bank as their investment). Occasionally, a loan of 80 per cent is possible.

The size of the loan depends on the expected project revenue, although it is typical for investors to take a cautious approach and to assume that the long-term income will be lower than assumed for normal operation. This ensures that the loan does not immediately run into problems in a year with poor wind conditions or other technical problems, and also takes into account the uncertainty associated with income prediction.

Typically, a bank will base the financial model on the 'exceedance cases' provided within the energy assessment for the project. The mean estimated production of the project (P50) may be used to decide on the size of the loan, or in some cases a value lower than the mean (for example P75 or P90). This depends on the level of additional cash cushioning that is available to cover costs and production variation over and above the money that is needed to make the debt payments. This is called the debt service cover ratio (DSCR) and is the ratio of cash available at the payment date to the debt service costs at that date. For example, if €1.4 million is available to make a debt payment (repayment and interest) of €1 million, the DSCR is 1.4:1.

The energy assumptions used for the financial model and associated DSCR are always a matter of negotiation with the bank as part of the loan agreement. Some banks will take a very cautious approach to the assumed energy production, with a low DCSR, and some will assume a more uncertain energy case, but with a high DSCR and sufficient cash cushioning to cover potential production variation.

The loan is often divided into two parts: a construction loan and a term loan. The construction loan provides funds for the construction of the project and becomes a term loan after completion. At the 'conversion' from a construction to a term loan, the terms and conditions associated with the loan change, as does the pricing of the debt. The term loan is usually less expensive than the construction loan, as the risks are lower during operation.

Typically, the length of a loan is between 10 and 15 years, but loan terms have become longer as banks have become more experienced in the wind industry.

The interest rate is often 1–1.5 per cent above the base rate at which the bank borrows their own funds (referred to as the interbank offer rate). In addition, banks usually charge a loan set-up fee of around 1 per cent of the loan cost, and they can make extra money by offering administrative and account services associated with the loan. Products to fix interest rates or foreign exchange rates are often sold to the project owner.

It is also typical for investors to have a series of requirements over the loan period; these are referred to as 'financial covenants'. These requirements are often the result of the due diligence and are listed within the 'financing agreement'. Typical covenants include the regular provision of information about operational and financial reporting, insurance coverage, and management of project bank accounts.

EXPERIENCE

In the last two decades, no wind industry project has ever had to be repossessed, although industry and project events have triggered some restructuring to adjust financing in difficult circumstances. The project finance mechanism has therefore served the industry and the banking community well. A decade ago, developers might have struggled to find a bank ready to loan to a project, whereas today banks often pursue developers to solicit their loan requirements. Clearly, this has improved the deals available to wind farm owners.

THE US

The description above covers most of the project-financed loans arranged outside the US. Inside the US there are some very particular structures that are rather more complicated, as the US market is driven by tax considerations.

The renewable energy incentive in the US is the Production Tax Credit (PTC), and hence tax is of primary rather than secondary importance. Since this publication focuses on the European market, it is not appropriate to describe the US approach in any detail, but basically it includes another layer of ownership – the tax investors – who own the vast majority of the project, but only for a limited period of time (say ten years), during which they can extract the tax advantage. After that period there is an ownership 'flip', and the project usually returns to its original owner. Many sophisticated tax structures have been developed for this purpose, and this characteristic has had a major effect on the way in which the US industry has developed. The owners of US wind farms tend to be large companies with a heavy tax burden. Another group of passive tax investors has also been created that does not exist in the wind industry outside the US.

Recent Developments

STRUCTURED FINANCE

The last five years has seen the emergence of a number of new forms of transaction for wind financing, including public and private bond or share issues. Much of the interest in such structures has come from renewable energy funds, long-term investors, such as pension funds, and even high net worth individuals seeking efficient investment vehicles. The principle behind a structured finance product is similar to that of a loan, being the investment of cash in return for interest payment; however, the structures are generally more varied than project finance loans. As a result, there have been a number of relatively short-term investments offered in the market, which have been useful products for project owners considering project refinancing after a few years of operation. Structured finance investors have had a considerable appetite for cross-border deals and have had a significant effect on liquidity for wind (and other renewable energy) projects.

BALANCE SHEET FINANCING

The wind industry is becoming a utility industry in which the major utilities are increasingly playing a big role. As a result, while there are still many small projects being developed and financed, an increasing number are being built 'on balance sheet' (in other words with the utility's cash). Such an approach removes the need for a construction loan and the financing consists of a term loan only.

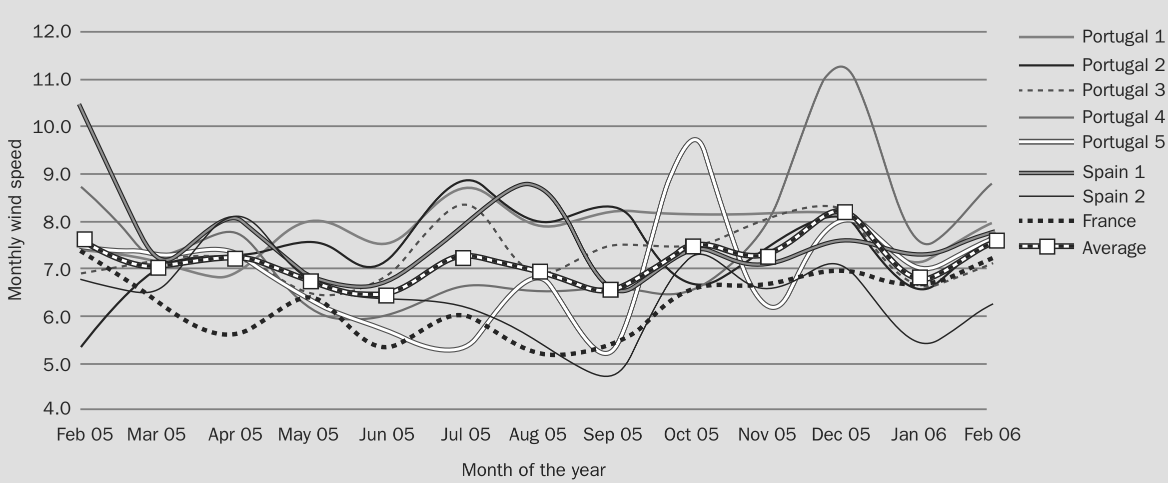
PORTFOLIO FINANCING

The arrival of balance sheet financing by the utilities naturally creates 'portfolio financing', in which banks are asked to finance a portfolio of wind farms rather than a single one. These farms are often operational and so data is available to allow for a far more accurate projection of production. The portfolio will usually include a range of projects separated by significant physical distances, with a range of turbine types. The use of different turbine types reduces the risk of widespread, or at least simultaneous, design faults, and the geographical spread 'evens out the wind'. It is possible to undertake a rigorous estimation of the way in which the geographical spread reduces fluctuations (Marco et al., 2007). Figure III.3.2 shows the averaging effect of a portfolio of eight wind power plants in three countries.

Finally, if the wind farms are in different countries, then the portfolio also reduces regulatory risks.

The risk associated with such portfolio financing is significantly lower than that of financing a single wind farm before construction and attracts more favourable terms. As a result, the interest in such financing is growing. Portfolio financing can be adopted even after the initial financing has been in place for some time. It is now quite common to see an owner collecting together a number of individually financed projects and refinancing them as a portfolio.

Figure III.3.2: The geographical portfolio effect



Source: Marco et al. (2007)

TECHNOLOGY RISK

The present 'sellers' market', characterised by the shortage in supply of wind turbines, has introduced a number of new turbine manufacturers, many of which are not financially strong and none of which has a substantial track record. Therefore, technology risk remains a concern for the banks, and the old-fashioned way of mitigating these risks, through extended warranties, is resisted forcefully by both new and experienced manufacturers. So technology risk has increased recently, rather than diminishing over time. However, some banks still show significant interest in lending to projects that use technology with relatively little operational experience.

OFFSHORE WIND

Offshore wind farms are now more common in Europe. The first few projects were financed in the way described above – by large companies with substantial financial clout, using their own funds. The initial involvement of banks was in the portfolio financing of a collection of assets, one of which was an offshore wind farm. Banks were concerned about the additional risks associated with an offshore development, and this approach allowed the risks to be diluted somewhat.

Although there are still relatively few offshore wind farms, banks are clearly interested in both term loans, associated with the operational phase of offshore wind farms, and the provision of construction finance. This clearly demonstrates the banks' appetite for wind energy lending. It is too early to define typical offshore financing, but it is likely to be more expensive than that for the equivalent onshore farm, at least until the banks gain greater confidence in the technology. The risk of poor availability as a result of poor accessibility is a particular concern.

BIG PROJECTS

Banks like big projects. The cost of the banks' own efforts and due diligence does not change significantly with the project (loan) size, so big projects are more attractive to them than smaller ones. Wind projects are only now starting to be big enough to interest some banks, so as project size increases, the banking community available to support the projects will grow. Furthermore, increasing project size brings more substantial sponsors, which is also reassuring for banks.

CONCLUSIONS

The nature of wind energy deals is changing. Although many small, privately owned projects remain, there has been a substantial shift towards bigger, utility-owned projects. This change brings new money to the industry, reduces dependence on banks for initial funding and brings strong sponsors.

Projects are growing and large-scale offshore activity is increasing. Since banks favour larger projects, this is a very positive change. If the general economic picture deteriorates, this may give rise to certain misgivings concerning project finance, in comparison to the last few years, but political and environmental support for renewable energy means that the funding of wind energy remains a very attractive proposition. Obtaining financing for the large-scale expansion of the industry will not be a problem.

III.4 PRICES AND SUPPORT MECHANISMS

Introduction: Types of RES-E Support Mechanism

When clustering the different types of support mechanisms available to electricity from renewable energy sources (RES-E), a fundamental distinction can be made between direct and indirect policy instruments. Direct policy measures aim to stimulate the installation of RES-E technologies immediately, whereas indirect instruments focus on improving long-term framework conditions. Besides regulatory instruments, voluntary approaches for the promotion of RES-E technologies also exist, mainly based on consumers' willingness to pay premium rates for green electricity. Further important classification criteria are whether policy instruments address price or quantity, and whether they support investments or generation.

Table III.4.1 provides a classification of the existing promotional strategies for renewables; there follows an explanation of the terminology used.

REGULATORY PRICE-DRIVEN STRATEGIES

Generators of RES-E receive financial support in terms of a subsidy per kW of capacity installed, or a payment per kWh produced and sold. The major strategies are:

- **investment-focused strategies**: financial support is given by investment subsidies, soft loans or tax credits (usually per unit of generating capacity); and
- **generation-based strategies**: financial support is a fixed regulated feed-in tariff (FIT) or a fixed premium (in addition to the electricity price) that a governmental institution, utility or supplier is legally obligated to pay for renewable electricity from eligible generators.

The difference between fixed FITs and premiums is as follows: for fixed FITs, the total feed-in price is fixed; for premium systems, the amount to be added to the electricity price is fixed. For the renewable plant owner, the total price received per kWh, in the premium scheme (electricity price plus the premium), is less predictable than under a feed-in tariff, since this depends on a volatile electricity price.

In principle, a mechanism based on a fixed premium/environmental bonus that reflects the external costs of conventional power generation could establish fair trade, fair competition and a level playing field between RES and conventional power sources in a competitive electricity market. From a market

Table III.4.1: Types of RES-E support mechanism

	Direct		Indirect
	Price-driven	Quantity-driven	
Regulatory			
Investment-focused	• Investment incentives • Tax credits • Low interest/Soft loans	• Tendering system for investment grant	• Environmental taxes • Simplification of authorisation procedures
Generation-based	• (Fixed) feed-in tariffs • Fixed premium system	• Tendering system for long-term contracts Tradable Green Certificate system	• Connection charges, balancing costs
Voluntary			
Investment-focused	• Shareholder programmes • Contribution programmes		• Voluntary agreements
Generation-based	• Green tariffs		

Source: Ragwitz et al. (2007)

development perspective, the advantage of such a scheme is that it allows renewables to penetrate the market quickly if their production costs drop below the electricity price plus premium. If the premium is set at the 'right' level (theoretically at a level equal to the external costs of conventional power), it allows renewables to compete with conventional sources without the need for governments to set 'artificial' quotas. Together with taxing conventional power sources in accordance with their environmental impact, well-designed fixed premium systems are theoretically the most effective way of internalising external costs.

In practice, however, basing the mechanism on the environmental benefits of renewables is challenging. Ambitious studies, such as the European Commission's ExternE project, which investigates the external costs of power generation, have been conducted in both Europe and America; these suggest that establishing exact costs is a complex matter. In reality, fixed premiums for wind power and other renewable energy technologies, such as the Spanish model, are based on estimated production costs and are fixed based on the electricity price, rather than on the environmental benefits of RES.

REGULATORY QUANTITY-DRIVEN STRATEGIES

The desired level of RES generation or market penetration – a quota or a Renewable Portfolio Standard – is defined by governments. The most important points are:

- **Tendering or bidding systems**: calls for tender are launched for defined amounts of capacity. Competition between bidders results in contract winners that receive a guaranteed tariff for a specified period of time.
- **Tradable certificate systems**: these systems are better known in Europe as Tradable Green Certificate (TCG) systems and in the US and Japan as Renewable Portfolio Standards (RPSs). In such systems, the generators (producers), wholesalers, distribution companies or retailers (depending on who is involved in the electricity supply chain) are obliged to supply or purchase a certain percentage of electricity from RES. At the date of settlement, they have to submit the required number of certificates to demonstrate compliance. Those involved may obtain certificates:
    - from their own renewable electricity generation;
    - by purchasing renewable electricity and associated certificates from another generator; and/or
    - by purchasing certificates without purchasing the actual power from a generator or broker, that is to say purchasing certificates that have been traded independently of the power itself.

The price of the certificates is determined, in principle, according to the market for these certificates (for example NordPool).

VOLUNTARY APPROACHES

This type of strategy is mainly based on the willingness of consumers to pay premium rates for renewable energy, due to concerns over global warming, for example. There are two main categories:

1. **investment-focused**: the most important are shareholder programmes, donation projects and ethical input; and
2. **generation-based**: green electricity tariffs, with and without labelling.

INDIRECT STRATEGIES

Aside from strategies which directly address the promotion of one (or more) specific renewable electricity technologies, there are other strategies that may have an indirect impact on the dissemination of renewables. The most important are:

- eco-taxes on electricity produced with non-renewable sources;

- taxes/permits on CO_2 emissions; and
- the removal of subsidies previously given to fossil and nuclear generation.

There are two options for the promotion of renewable electricity via energy or environmental taxes:

1. exemption from taxes (such as energy and sulphur taxes); and
2. if there is no exemption for RES, taxes can be (partially or wholly) refunded.

Both measures make RES more competitive in the market and are applicable for both established and new plants.

Indirect strategies also include the institutional promotion of the deployment of RES plants, such as site planning and easy connection to the grid, and the operational conditions of feeding electricity into the system. First, siting and planning requirements can reduce the potential opposition to RES-E plants if they address issues of concern, such as noise and visual or environmental impacts. Laws can be used to, for example, set aside specific locations for development and/or omit areas that are particularly open to environmental damage or injury to birds.

Second, complementary measures also concern the standardisation of economic and technical connection conditions. Interconnection requirements are often unnecessarily onerous and inconsistent and can lead to high transaction costs for project developers, particularly if they need to hire technical and legal experts. Safety requirements are essential, particularly in the case of interconnection in weak parts of the grid. However, unclear criteria on interconnections can potentially lead to higher prices for access to the grid and use of transmission lines, or even unreasonable rejections of transmission access. Therefore, it is recommended that authorities clarify the safety requirements and the rules on the burden of additional expenses.

Finally, rules must be established to govern the responsibility for physical balancing associated with some technologies' variable production, in particular for wind power.

COMPARISON OF PRICE-DRIVEN VERSUS QUANTITY-DRIVEN INSTRUMENTS

In the following section, an assessment of direct promotional strategies is carried out by focusing on the comparison between price-driven (for example FITs, investment incentives and tax credits) and quantity-driven (for example Tradable Green Certificate (TGC)-based quotas and tendering systems) strategies. The different instruments can be described as follows:

- **Feed-in tariffs (FITs) are generation-based, price-driven incentives**. The price per unit of electricity that a utility, supplier or grid operator is legally obliged to pay for electricity from RES-E producers is determined by this system. Thus a federal (or provincial) government regulates the tariff rate. It usually takes the form of either a fixed price to be paid for RES-E production or an additional premium on top of the electricity market price paid to RES-E producers. Besides the level of the tariff, its guaranteed duration represents an important parameter for an appraisal of the actual financial incentive. FITs allow technology-specific promotion, as well as an acknowledgement of future cost reductions by applying dynamic decreasing tariffs.
- **Quota obligations based on Tradable Green Certificates (TGCs) are generation-based, quantity-driven instruments**. The government defines targets for RES-E deployment and requires a particular party in the electricity supply chain (for example the generator, wholesaler or consumer) to fulfil certain obligations. Once defined, a parallel market for renewable energy certificates is established and their price is set following demand and supply conditions (forced by the obligation). Hence for RES-E producers, financial support may arise from selling certificates, in addition to the

revenues from selling electricity on the power market. Technology-specific promotion in TGC systems, is also possible in principle. However, market separation for different technologies would lead to much smaller and less liquid markets. One solution could be to weight certificates from different technologies, but the key dilemma is how to find weights that are correct or at least widely accepted as fair.

- **Tendering systems are quantity-driven mechanisms**. Financial support can either be investment-focused or generation-based. In the first case, a fixed amount of capacity to be installed is announced and contracts are given following a predefined bidding process, which offers winners a set of favourable investment conditions, including investment grants per kW installed. The generation-based tendering systems work in a similar way; but instead of providing up-front support, they offer support in the form of a 'bid price' per kWh for a guaranteed duration.
- **Investment incentives are price-driven instruments** that establish an incentive for the development of RES-E projects as a percentage of total costs, or as a predefined amount of money per kW installed. The level of these incentives is usually technology-specific.
- **Production tax incentives are also price-driven, generation-based mechanisms** that work through payment exemptions from the electricity taxes applied to all producers. Hence this type of instrument differs from premium feed-in tariffs only in terms of the cash flow for RES-E producers; it represents a negative cost instead of additional revenue.

Overview of the Different RES-E Support Schemes in EU-27 Countries

Figure III.4.1 shows the evolution of the different RES-E support instruments from 1997 to 2007 in each of the EU-27 Member States. Some countries already have more than ten years' experience with RES-E support schemes.

Initially, in the old EU-15, only 8 out of the 15 Member States avoided a major policy shift between 1997 and 2005. The current discussion within EU Member States focuses on the comparison between two opposing systems – the FIT system and quota regulation in combination with a TGC market. The latter has recently replaced existing policy instruments in some European countries, such as Belgium, Italy, Sweden, the UK and Poland. Although these new systems were not introduced until after 2002, the announced policy changes caused investment instabilities prior to this date. Other policy instruments, such as tender schemes, are no longer used as the main policy scheme in any European country. However, there are instruments, such as production tax incentives and investment incentives, that are frequently used as supplementary instruments; only Finland and Malta use them as their main support scheme.

Table III.4.2 gives a detailed overview of the main support schemes for wind energy in the EU-27 Member States.

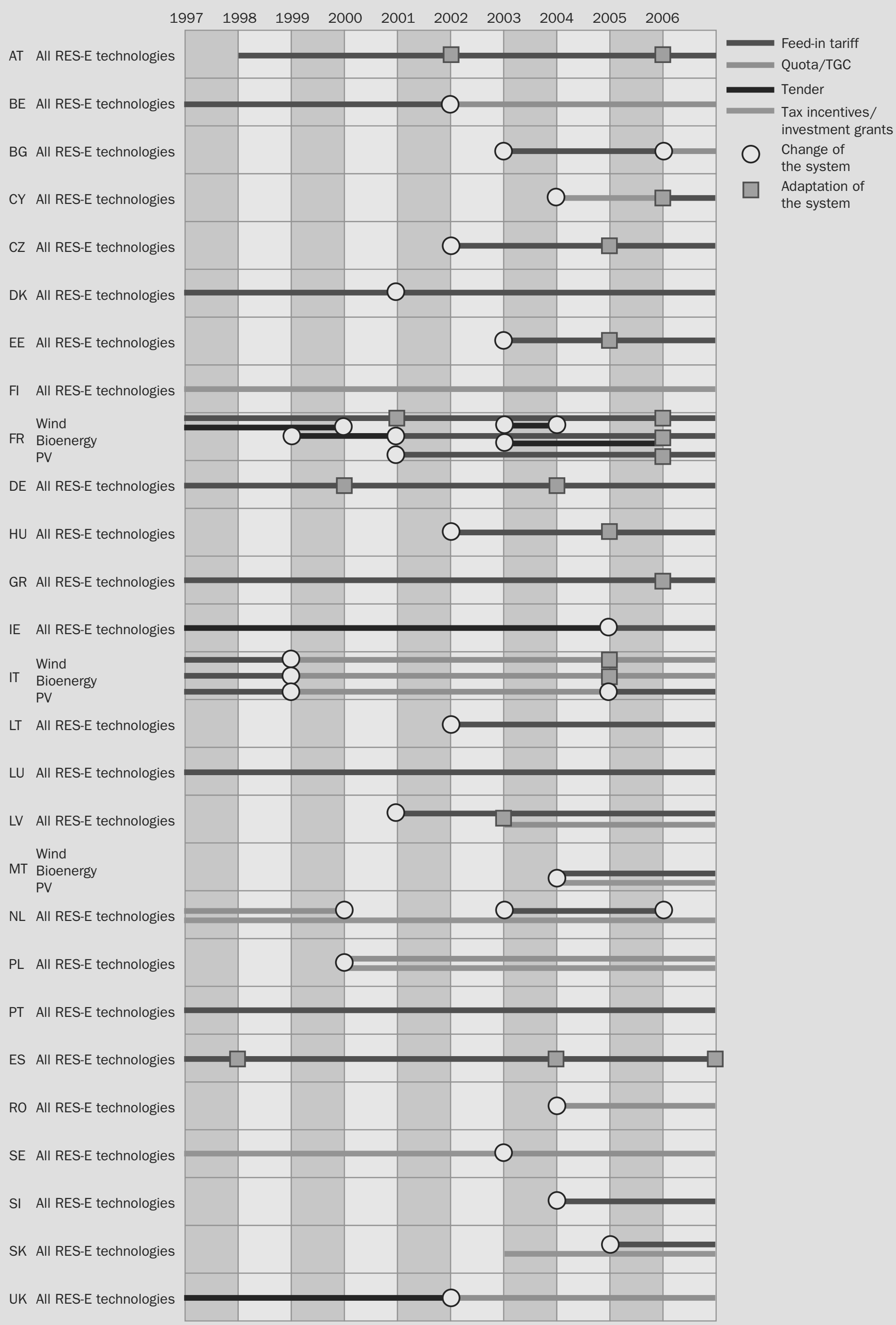
In Table III.4.3, a more detailed overview is provided on implemented RES-E support schemes in the EU-27 Member States in 2007, detailing countries, strategies and the technologies addressed. In the EU-27, FITs serve as the main policy instrument.

For a detailed overview of the EU Member States' support schemes, please refer to Appendix I.

Evaluation of the Different RES-E Support Schemes (Effectiveness and Economic Efficiency)

In reviewing and evaluating the different RES-E support schemes described above, the key question is whether each of these policy instruments has been a success. In order to assess the success of the

Figure III.4.1: Evolution of the main policy support schemes in EU-27 Member States



Source: Ragwitz et al. (2007)

Table III.4.2: Overview of the main RES-E support schemes for wind energy in the EU-27 Member States as implemented in 2007

Country	Main support instrument for wind	Settings of the main support instrument for wind in detail
Austria	FIT	New fixed feed-in tariff valid for new RES-E plants permitted in 2006 and/or 2007: fixed FIT for years 1–9 (€76.5/MWh for 2006 as a starting year; €75.5/MWh for 2007). Years 10 and 11 at 75% and year 12 at 50%.
Belgium	Quota obligation system with TGC, combined with minimum price for wind	Flanders, Wallonia and Brussels have introduced a quota obligation system (based on TGCs). The minimum price for wind onshore (set by the federal government) is €80/MWh in Flanders, €65/MWh in Wallonia and €50/MWh in Brussels. Wind offshore is supported at the federal level, with a minimum price of €90/MWh (the first 216 MW installed at €107/MWh minimum).
Bulgaria	Mandatory purchase price	Mandatory purchase prices (set by the State Energy Regulation Commission): new wind installations after 1 January 2006 (duration 12 years each): (i) effective operation >2250 h/a: €79.8/MWh; (ii) effective operation <2250 h/a: €89.5/MWh.
Cyprus	FIT	Fixed feed-in tariff since 2005: in the first 5 years €92/MWh, based on mean values of wind speeds; in the next 10 years €48–92/MWh according to annual wind operation hours (<1750–2000 h/a: €85–92/MWh; 2000–2550 h/a: €63–85/MWh; 2550–3300 h/a: €48–63/MWh).
Czech Republic	Choice between FIT and Premium Tariff	Fixed feed-in tariff: €88–114/MWh in 2007 (duration: equal to the lifetime); Premium Tariff: €70–96/MWh in 2007 (duration: newly set every year).
Denmark	Market price and premium for wind onshore; tendering system for wind offshore	**Wind onshore**: Market price plus premium of €13/MWh (20 years); additionally, balancing costs are refunded at €3/MWh, leading to a total tariff of approximately €57/MWh. **Wind offshore**: €66–70/MWh (i.e. market price plus a premium of €13/MWh); a tendering system is applied for future offshore wind parks, balancing costs are borne by the owners.
Estonia	FIT	Fixed feed-in tariff for all RES: €52/MWh (from 2003 to present); current support mechanisms will be terminated in 2015.
Finland	Tax exemptions and investment subsidies	Mix of tax exemptions (refund) and investment subsidies: tax refund of €6.9/MWh for wind (€4.2/MWh for other RES-E). Investment subsidies up to 40% for wind (up to 30% for other RES-E).
France	FIT	**Wind onshore**: €82/MWh for 10 years; €28–82/MWh for the following 5 years (depending on the local wind conditions). **Wind offshore**: €130/MWh for 10 years; €30–130/MWh for the following 10 years (depending on the local wind conditions).
Germany	FIT	**Wind onshore (20 years in total)**: €83.6/MWh for at least 5 years; €52.8/MWh for further 15 years (annual reduction of 2% is taken into account). **Wind offshore (20 years in total)**: €91/MWh for at least 12 years; €61.9/MWh for further 8 years (annual reduction of 2% taken into account).
Greece	FIT	**Wind onshore**: €73/MWh (mainland); €84.6/MWh (autonomous islands). **Wind offshore**: €90/MWh (mainland); €90/MWh (autonomous islands); feed-in tariffs guaranteed for 12 years (possible extension up to 20 years).
Hungary	FIT	Fixed feed-in tariff (since 2006): €95/MWh; duration: according to the lifetime of technology.
Ireland	FIT	Fixed feed-in tariff (since 2006); guaranteed for 15 years: Wind >5 MW: €57/MWh; Wind <5 MW: €59/MWh.
Italy	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity producers and importers. Certificates are issued for RES-E capacity during the first 12 years of operation, except biomass, which receives certificates for 100% of electricity production for first 8 years and 60% for next 4 years. In 2005 the average certificate price was €109/MWh.

continued

Table III.4.2: (continued)

Country	Main support instrument for wind	Settings of the main support instrument for wind in detail
Latvia	Main policy support instrument currently under development	Frequent policy changes and short duration of guaranteed feed-in tariffs (phased out in 2003) result in high investment uncertainty. Main policy currently under development.
Lithuania	FIT	Fixed feed-in tariff (since 2002): €63.7/MWh, guaranteed for 10 years.
Luxembourg	FIT	Fixed feed-in tariff: (i) <0.5 MW: €77.6/MWh; (ii) >0.5 MW: max €77.6/MWh (i.e. decreasing for higher capacities); guaranteed for 10 years.
Malta	No support instrument yet	Very little attention to RES-E (including wind) support so far. A low VAT rate is in place.
Netherlands	Premium Tariff (€0/MWh since August 2006)	Premium feed-in tariffs guaranteed for 10 years were in place from July 2003. For each MWh RES-E generated, producers receive a green certificate. The certificate is then delivered to the feed-in tariff administrator to redeem tariff. Government put all premium RES-E support at zero for new installations from August 2006 as it believed target could be met with existing applicants.
Poland	Quota obligation system; TGCs introduced end 2005 plus renewables are exempted from excise tax	Obligation on electricity suppliers with RES-E targets specified from 2005 to 2010. Poland has a RES-E and primary energy target of 7.5% by 2010. RES-E share in 2005 was 2.6% of gross electricity consumption.
Portugal	FIT	Fixed feed-in tariff (average value 2006): €74/MWh, guaranteed for 15 years.
Romania	Quota obligation system with TGCs	Obligation on electricity suppliers with targets specified from 2005 (0.7% RES-E) to 2010 (8.3% RES-E). Minimum and maximum certificate prices are defined annually by Romanian Energy Regulatory Authority. Non-compliant suppliers pay maximum price (i.e. €63/MWh for 2005–2007; €84/MWh for 2008–2012).
Slovakia	FIT	Fixed feed-in tariff (since 2005): €55–72/MWh; FITs for wind are set that way so that a rate of return on the investment is 12 years when drawing a commercial loan.
Slovenia	Choice between FIT and premium tariff	Fixed feed-in tariff: (i) <1 MW: €61/MWh; (ii) >1 MW: €59/MWh. Premium tariff: (i) <1 MW: €27/MWh; (ii) >1 MW: €25/MWh. Fixed feed-in tariff and premium tariff guaranteed for 5 years, then reduced by 5%. After ten years reduced by 10% (compared to original level).
Spain	Choice between FIT and premium tariff	Fixed feed-in tariff: (i) <5 MW: €68.9/MWh; (ii) >5 MW: €68.9/MWh; Premium tariff: (i) <5 MW: €38.3/MWh; (ii) >5 MW: €38.3/MWh. Duration: no limit, but fixed tariffs are reduced after either 15, 20 or 25 years, depending on technology.
Sweden	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity consumers. Obligation level of 51% RES-E defined to 2010. Non-compliance leads to a penalty, which is fixed at 150% of the average certificate price in a year (average certificate price was €69/MWh in 2007).
UK	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity suppliers. Obligation target increases to 2015 (15.4% RES-E; 5.5% in 2005) and guaranteed to stay at least at that level until 2027. Electricity companies which do not comply with the obligation have to pay a buy-out penalty (€65.3/MWh in 2005). Tax exemption for electricity generated from RES is available.

Sources: Auer (2008); Ragwitz et al. (2007)

Table III.4.3: Overview of the main RES-E support schemes in the EU-27 Member States as implemented in 2007

Country	Main electricity support schemes	Comments
Austria	FITs combined with regional investment incentives	Until December 2004, FITs were guaranteed for 13 years. In November 2005 it was announced that, from 2006 onwards, full FITs would be available for 10 years, with 75% available in year 11 and 50% in year 12. New FIT levels are announced annually and support is granted on a first-come, first-served basis. From May 2006 there has been a smaller government budget for RES-E support. At present, a new amendment is tabled, which suggests extending the duration of FIT fuel-independent technologies to 13 years (now 10 years) and fuel-dependent technologies to 15 years (now 10 years).
Belgium	Quota obligation system/ TGC combined with minimum prices for electricity from RES	The federal government has set minimum prices for electricity from RES. Flanders and Wallonia have introduced a quota obligation system (based on TGCs) with the obligation on electricity suppliers. In all three of the regions, including Brussels, a separate market for green certificates has been created. Offshore wind is supported at the federal level.
Bulgaria	Mandatory purchase of renewable electricity by electricity suppliers for minimum prices (essentially FITs) plus tax incentives	The relatively low level of incentives makes the penetration of renewables particularly difficult, since the current commodity prices for electricity are still relatively low. A green certificate system to support renewable electricity developments has been proposed, for implementation in 2012, to replace the mandatory purchase price. Bulgaria recently agreed upon an indicative target for renewable electricity with the European Commission, which is expected to provide a good incentive for further promotion of renewable support schemes.
Cyprus	FITs (since 2006), supported by investment grant scheme for the promotion of RES	An Enhanced Grant Scheme was introduced in January 2006, in the form of government grants worth 30–55% of investment, to provide financial incentives for all renewable energy. FITs with long-term contracts (15 years) were also introduced in 2006.
Czech Republic	FITs (since 2002), supported by investment grants	Relatively high FITs, with a lifetime guarantee of support. Producers can choose fixed FITs or a premium tariff (green bonus). For biomass co-generation, only green bonus applies. FIT levels are announced annually, but are increased by at least 2% each year.
Denmark	Premium FIT for onshore wind, tender scheme for offshore wind and fixed FITs for others	Duration of support varies from 10 to 20 years, depending on the technology and scheme applied. The tariff level is generally rather low compared to the formerly high FITs. A net metering approach is taken for photovoltaics.
Estonia	FIT system	FITs paid for 7–12 years, but not beyond 2015. Single FIT level for all RES-E technologies. Relatively low FITs make new renewable investments very difficult.
Finland	Energy tax exemption combined with investment incentives	Tax refund and investment incentives of up to 40% for wind and up to 30% for electricity generation from other RES.
France	FITs plus tenders for large projects	For power plants <12 MW, FITs are guaranteed for 15 or 20 years (offshore wind, hydro and PV). From July 2005, FIT for wind is reserved for new installations within special wind energy development zones. For power plants >12 MW (except wind) a tendering scheme is in place.
Germany	FITs	FITs are guaranteed for 20 years (Renewable Energy Act) and soft loans are also available.
Greece	FITs combined with investment incentives	FITs are guaranteed for 12 years, with the possibility of extension up to 20 years. Investment incentives up to 40%.
Hungary	FIT (since January 2003, amended 2005), combined with purchase obligation and grants	Fixed FITs recently increased and differentiated by RES-E technology. There is no time limit for support defined by law, so in theory guaranteed for the lifetime of the installation. Plans to develop TGC system; when this comes into effect, the FIT system will cease to exist.
Ireland	FIT scheme replaced tendering scheme in 2006	New premium FITs for biomass, hydropower and wind started in 2006. Tariffs guaranteed to supplier for up to 15 years. Purchase price of electricity from the generator is negotiated between generators and suppliers. However, support may not extend beyond 2024, so guaranteed premium FIT payments should start no later than 2009.

continued

Table III.4.3: (continued)

Country	Main electricity support schemes	Comments
Italy	Quota obligation system with TGCs; fixed FIT for PV	Obligation (based on TGCs) on electricity producers and importers. Certificates are issued for RES-E capacity during the first 12 years of operation, except for biomass, which receives certificates for 100% of electricity production for the first 8 years and 60% for the next 4 years. Separate fixed FIT for PV, differentiated by size, and building integrated. Guaranteed for 20 years. Increases annually in line with retail price index.
Latvia	Main policy under development; quota obligation system (since 2002) without TGCs, combined with FITs (phased out in 2003)	Frequent policy changes and short duration of guaranteed FITs result in high investment uncertainty. Main policy currently under development. Quota system (without TGCs) typically defines small RES-E amounts to be installed. High FIT scheme for wind and small hydropower plants (less than 2 MW) was phased out as from January 2003.
Lithuania	FITs combined with purchase obligation	Relatively high fixed FITs for hydro (<10 MW), wind and biomass, guaranteed for 10 years. Closure of Ignalina nuclear plant, which currently supplies the majority of electricity in Lithuania, will strongly affect electricity prices and thus the competitive position of renewables, as well as renewable support. Good conditions for grid connections. Investment programmes limited to companies registered in Lithuania. Plans exist to introduce a TGC system after 2010.
Luxembourg	FITs	FITs guaranteed for 10 years (20 years for PV). Also investment incentives available.
Malta	Low VAT rate and very low FIT for solar	Very little attention to RES support so far. Very low FIT for PV is a transitional measure.
Netherlands	FITs (tariff zero from August 2006)	Premium FITs guaranteed for 10 years have been in place since July 2003. For each MWh RES-E generated, producers receive a green certificate from the issuing body (CERTIQ). Certificate is then delivered to FIT administrator (ENERQ) to redeem tariff. Government put all premium RES-E support at zero for new installations from August 2006, as it believed target could be met with existing applicants. Premium for biogas (<2 MWe) immediately reinstated. New support policy under development. Fiscal incentives for investments in RES are available. Energy tax exemption for electricity from RES ceased 1 January 2005.
Poland	Quota obligation system; TGCs introduced from end 2005, plus renewables are exempted from the (small) excise tax	Obligation on electricity suppliers with targets specified from 2005 to 2010. Penalties for non-compliance were defined in 2004, but were not properly enforced until end of 2005. It has been indicated that from 2006 onwards the penalty will be enforced.
Portugal	FITs combined with investment incentives	Fixed FITs guaranteed for 15 years. Level dependent on time of electricity generation (peak/off peak), RES-E technology and resource. Is corrected monthly for inflation. Investment incentives up to 40%.
Romania	Quota obligation with TGCs; subsidy fund (since 2004)	Obligation on electricity suppliers, with targets specified from 2005 to 2010. Minimum and maximum certificate prices are defined annually by Romanian Energy Regulatory Authority. Non-compliant suppliers pay maximum price. Romania recently agreed on an indicative target for renewable electricity with the European Commission, which is expected to provide a good incentive for further promotion of renewable support schemes.
Slovak Republic	Programme supporting RES and energy efficiency, including FITs and tax incentives	Fixed FIT for RES-E was introduced in 2005. Prices set so that a rate of return on the investment is 12 years when drawing a commercial loan. Low support, lack of funding and lack of longer-term certainty in the past have made investors very reluctant.

continued

Table III.4.3: (continued)

Country	Main electricity support schemes	Comments
Slovenia	FITs, CO_2 taxation and public funds for environmental investments	Renewable electricity producers choose between fixed FITs and premium FITs. Tariff levels defined annually by Slovenian Government (but have not changed since 2004). Tariff guaranteed for 5 years, then reduced by 5%. After 10 years, reduced by 10% (compared to original level). Relatively stable tariffs combined with long-term guaranteed contracts makes system quite attractive to investors.
Spain	FITs	Electricity producers can choose a fixed FIT or a premium on top of the conventional electricity price. No time limit, but fixed tariffs are reduced after either 15, 20 or 25 years depending on technology. System very transparent. Soft loans, tax incentives and regional investment incentives are available.
Sweden	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity consumers. Obligation level defined to 2010. Non-compliance leads to a penalty, which is fixed at 150% of the average certificate price in a year. Investment incentive and a small environmental bonus available for wind energy.
UK	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity suppliers. Obligation target increases to 2015 and guaranteed to stay at that level (as a minimum) until 2027. Electricity companies that do not comply with the obligation have to pay a buy-out penalty. Buy-out fund is recycled back to suppliers in proportion to the number of TGCs they hold. The UK is currently considering differentiating certificates by RES-E technology. Tax exemption for electricity generated from RES is available (Levy Exemption Certificates, which give exemption from the Climate Change Levy).

Source: Ragwitz et al. (2007)

different policy instruments, the most important criteria are:

- **Effectiveness**: Did the RES-E support programmes lead to a significant increase in deployment of capacities from RES-E in relation to the additional potential? The effectiveness indicator measures the relationship of the new generated electricity within a certain time period to the potential of the technologies.
- **Economic efficiency**: What was the absolute support level compared to the actual generation costs of RES-E generators, and what was the trend in support over time? How is the net support level of RES-E generation consistent with the corresponding effectiveness indicator?

Other important performance criteria are the credibility for investors and the reduction of costs over time. However, effectiveness and economic efficiency are the two most important criteria – these are discussed in detail in the following sections.

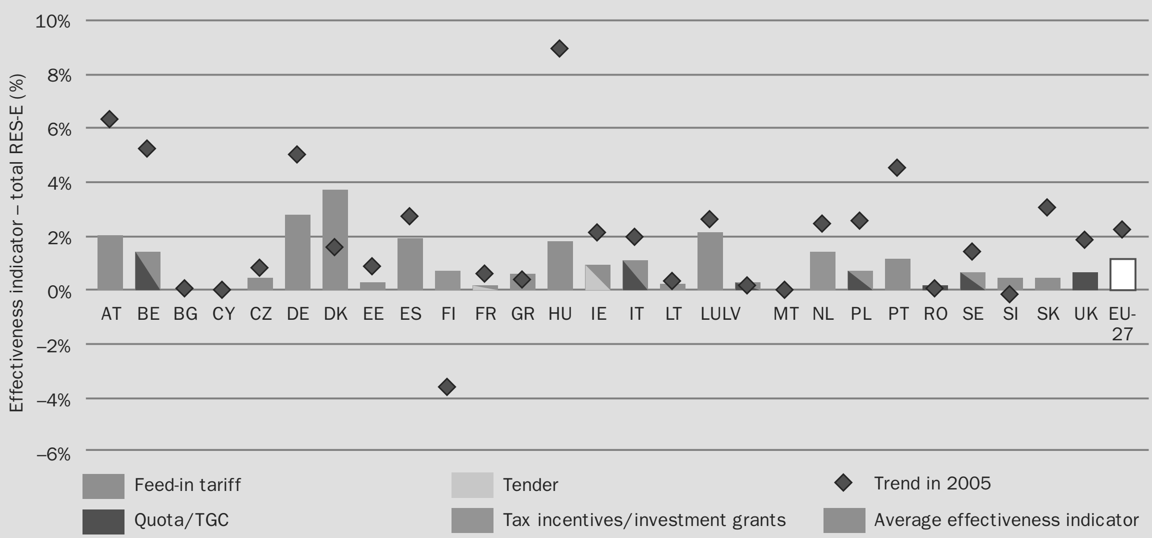
EFFECTIVENESS OF POLICY INSTRUMENTS

When analysing the effectiveness of RES-E support instruments, the quantities installed are of particular interest. In order to be able to compare the performance between the different countries, the figures are related to the size of the population. Here we look at all new RES-E in total, as well as wind and PV in detail.

Figure III.4.2 depicts the effectiveness of total RES-E policy support for the period 1998 to 2005, measured in yearly additional electricity generation in comparison to the remaining additional available potential for each EU-27 Member State. The calculations refer to following principle:

$$E_n^i = \frac{G_n^i - G_{n-1}^i}{ADDPOT_n^i} = \frac{G_n^i - G_{n-1}^i}{POT_{2020}^i - G_{n-1}^i}$$

Figure III.4.2: Policy effectiveness of total RES-E support for 1998–2005 measured in annual additional electricity generation in comparison to the remaining additional available potential for each EU-27 Member State



Source: Eurostat (2007a)

Effectiveness indicator for RES technology i for the year n	Existing electricity generation potential by RES technology i in year n
E_n^i	G_n^i
Additional generation potential of RES technology i in year n until 2020	Total generation potential of RES technology i until 2020
$ADDPOT_n^i$	POT_n^i

It is clearly indicated in Figure III.4.2 that countries with FITs as a support scheme achieved higher effectiveness compared to countries with a quota/TGC system or other incentives. Denmark achieved the highest effectiveness of all the Member States, but it is important to remember that very few new generation plants have been installed in recent years. Conversely, in Germany and Portugal there has been a significant increase in new installations recently. Among the new Member States, Hungary and Poland have implemented the most efficient strategies in order to promote 'new' renewable energy sources.

ECONOMIC EFFICIENCY

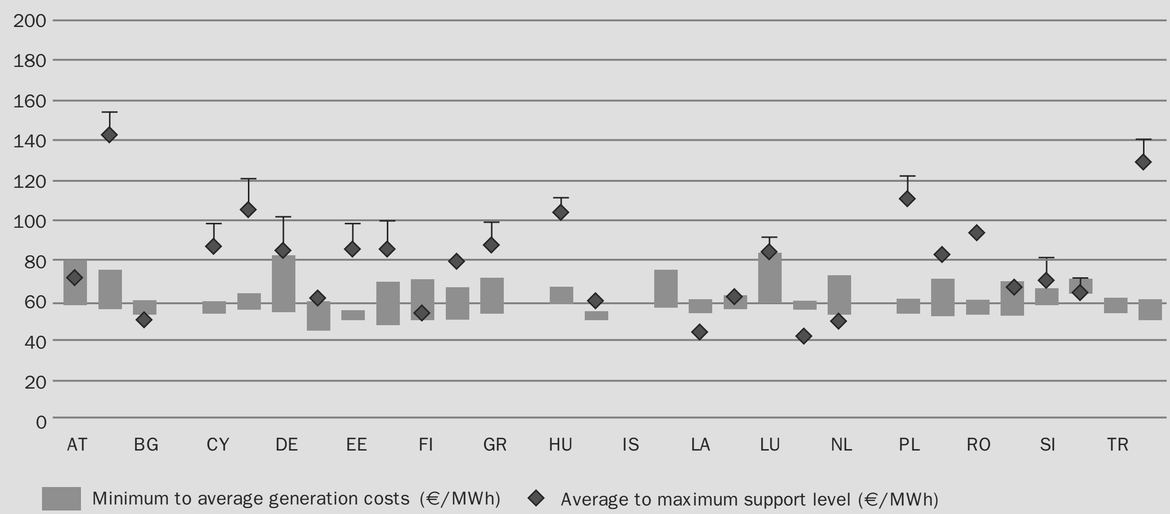
Next we compare the economic efficiency of the support programmes described above. In this context, three aspects are of interest:

1. absolute support levels;
2. total costs to society; and
3. dynamics of the technology.

Here, as an indicator, the support levels are compared specifically for wind power in the EU-27 Member States.

Figure III.4.3 shows that the support level and generation costs are almost equal. Countries with relatively high average generation costs frequently show a higher support level, but a clear deviation from this rule can be found in the three quota systems in Belgium, Italy and the UK, for which the support is presently significantly higher than the generation costs.

Figure III.4.3: Onshore wind: support level ranges (average to maximum support) in EU countries in 2006 (average tariffs are indicative) compared to the long-term marginal generation costs (minimum to average costs)



Note: Support level is normalised to 15 years.

Source: Adapted from Ragwitz et al. (2007)

The reasons for the higher support level, expressed by the current green certificate prices, may differ; but the main reasons are risk premiums, immature TGC markets and inadequate validity times of certificates (Italy and Belgium).

For Finland, the level of support for onshore wind is too low to initiate any steady growth in capacity. In the case of Spain and Germany, the support level indicated in Figure III.4.3 appears to be above the average level of generation costs. However, the potential with fairly low average generation costs has already been exploited in these countries, due to recent market growth. Therefore, a level of support that is moderately higher than average costs seems to be reasonable. In an assessment over time, the potential technology learning effects should also be taken into account in the support scheme.

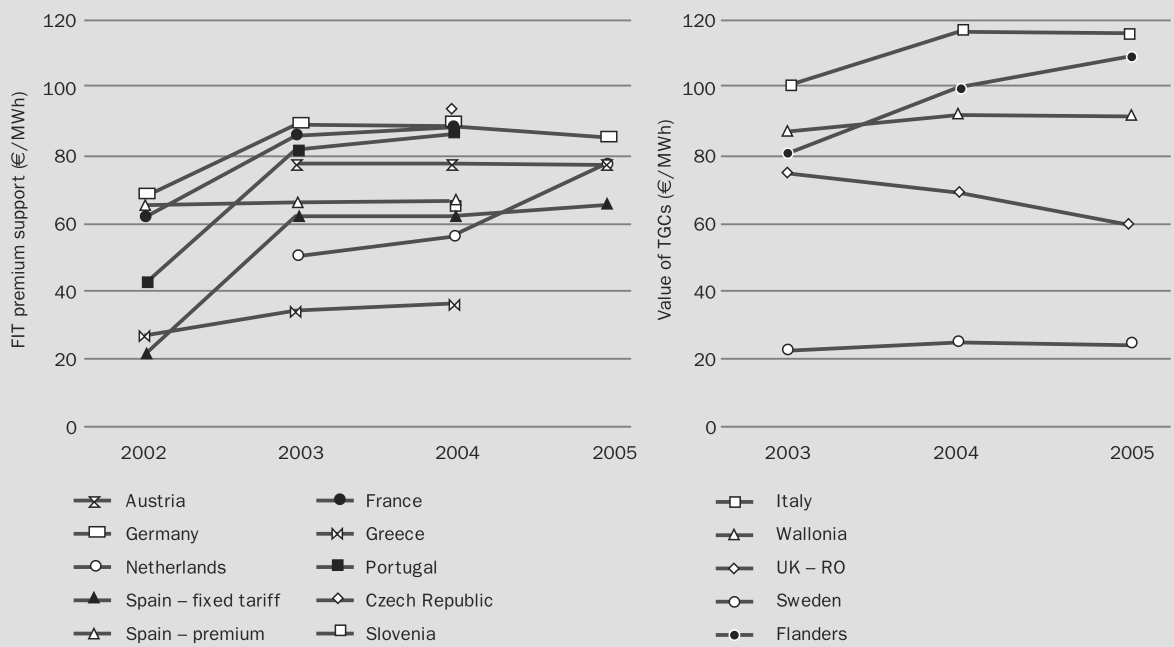
Figure III.4.4 illustrates a comparative overview of the ranges of TGC prices and FITs in selected EU-27 countries. With the exception of Sweden, TGC prices are much higher than those for guaranteed FITs, which also explains the high level of support in these countries, as shown in Figure III.4.4.

Policy Recommendations for the Design Criteria of RES-E Support Instruments

CONSIDERATION OF A DYNAMIC PORTFOLIO OF RES-E SUPPORT SCHEMES

Regardless of whether a national or international support system is concerned, a single instrument is not usually enough to stimulate the long-term growth of RES-E. Since, in general, a broad portfolio of RES technologies should be supported, the mix of instruments selected should be adjusted accordingly. Whereas investment grants are normally suitable for supporting immature technologies, FITs are appropriate for the interim stage of the market introduction of a

Figure III.4.4: Comparison of premium support level: FIT premium support versus value of TGCs



Note: The FIT premium support level consists of FIT minus the national average spot market electricity price.

Source: EEG (2007)

technology. A premium, or a quota obligation based on TGC, is likely to be the most relevant choice when:

- markets and technologies are sufficiently mature;
- the market size is large enough to guarantee competition among the market actors; and
- competition on the conventional power market is guaranteed.

Such a mix of instruments can then be supplemented by tender procedures, which are very efficient, for example, in the case of large-scale projects such as offshore wind.

STRIVING FOR OPTIMAL RES-E INSTRUMENT DESIGN IN TERMS OF EFFECTIVENESS AND EFFICIENCY

Most instruments still have significant potential for improvement, even after the minimum design criteria described above have been met. A few examples of such optimisation options are as follows:

- In a feed-in system, a stepped design can clearly increase the economic efficiency of the instrument, especially in countries where the productivity of a technology varies significantly between different technology bands.
- In quota systems based on TGCs, the technology or band specification that is currently being tested in Italy (based on technology-specific certification periods) and in Belgium (based on technology-specific certificate values) may be a relevant option for increasing both the instrument's effectiveness and its efficiency. However, such technology specification should not be carried out by setting technology-specific quotas and separating the TGC market, as this would negatively influence market liquidity. Furthermore, the risk premium might go down if minimum tariffs were to be introduced in a quota system.

III.5 WIND POWER ON THE SPOT MARKET

Introduction

In a number of countries, wind power has an increasing share of total power production. This applies particularly to countries such as Denmark, Spain and Germany, where the shares of wind in terms of total power supply are currently 21 per cent, 12 per cent and 7 per cent respectively. In these cases, wind power is becoming an important player in the power market, and such high shares can significantly influence prices.

Different power market designs have a significant influence on the integration of wind power. In the following section, short descriptions of the most important market designs within the increasingly liberalised European power industry are presented, along with more detailed descriptions of spot and balancing markets. Finally, the impacts of Danish wind power on the Scandinavian power exchange, NordPool's Elspot, which comprises Denmark, Norway, Sweden and Finland, are discussed in more detail.

Power Markets

As part of the gradual liberalisation of the EU electricity industry, power markets are increasingly organised in a similar way, where a number of closely related services are provided. This applies to a number of liberalised power markets, including those of the Nordic countries, Germany, France and The Netherlands. Common to all these markets is the existence of five types of power market:

- **Bilateral electricity trade or OTC (over the counter) trading:** Trading takes place bilaterally outside the power exchange, and prices and amounts are not made public.
- **The day-ahead market (spot market):** A physical market where prices and amounts are based on supply and demand. Resulting prices and the overall amounts traded are made public. The spot market is a day-ahead market where bidding closes at noon for deliveries from midnight and 24 hours ahead.
- **The intraday market:** Quite a long time period remains between close of bidding on the day-ahead market and the regulating power market (below). The intraday market is therefore introduced as an 'in-between market', where participants in the day-ahead market can trade bilaterally. Usually, the product traded is the one-hour-long power contract. Prices are published and based on supply and demand.
- **The regulating power market (RPM):** A real-time market covering operation within the hour. The main function of the RPM is to provide power regulation to counteract imbalances related to day-ahead operations planned. Transmission system operators (TSOs) alone make up the demand side of this market, and approved participants on the supply side include both electricity producers and consumers.
- **The balancing market:** This market is linked to the RPM and handles participant imbalances recorded during the previous 24-hour period of operation. The TSO alone acts on the supply side to settle imbalances. Participants with imbalances on the spot market are price takers on the RPM/balance market.

The day-ahead and regulating markets are particularly important for the development and integration of wind power in the power systems. The Nordic power exchange, NordPool, is described in more detail in the following section as an example of these power markets.

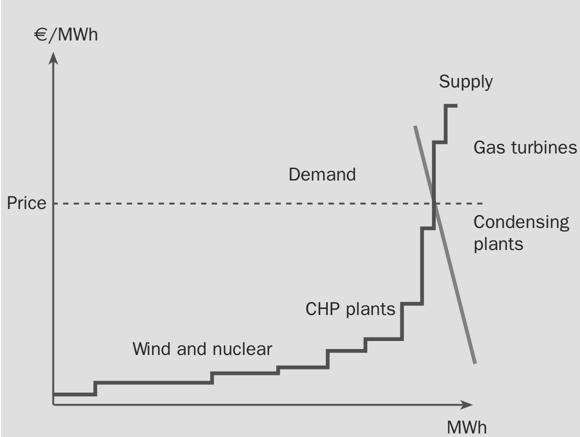
THE NORDIC POWER MARKET: NordPool SPOT MARKET

The NordPool spot market (Elspot) is a day-ahead market, where the price of power is determined by supply and demand. Power producers and consumers submit their bids to the market 12 to 36 hours in advance of delivery, stating the quantities of electricity supplied or demanded and the corresponding price. Then, for each hour, the price that clears the market (balancing supply with demand) is determined on the NordPool power exchange.

In principle, all power producers and consumers can trade on the exchange, but in reality, only big consumers (distribution and trading companies and large industries) and generators act on the market, while the smaller companies form trading cooperatives (as is the case for wind turbines), or engage with larger traders to act on their behalf. Approximately 45 per cent of total electricity production in the Nordic countries is traded on the spot market. The remaining share is sold through long-term, bilateral contracts, but the spot price has a considerable impact on prices agreed in such contracts. In Denmark, the share sold at the spot market is as high as 80 per cent.

Figure III.5.1 shows a typical example of an annual supply and demand curve for the Nordic power system. As shown, the bids from nuclear and wind power enter

Figure III.5.1: Supply and demand curve for the NordPool power exchange



Source: Risø DTU

the supply curve at the lowest level, due to their low marginal costs, followed by combined heat and power plants, while condensing plants are those with the highest marginal costs of power production. Note that hydropower is not identified on the figure, since bids from hydro tend to be strategic and depend on precipitation and the level of water in reservoirs.

In general, the demand for power is highly inelastic (meaning that demand remains almost unchanged in spite of a change in the power price), with mainly Norwegian and Swedish electro-boilers and power-intensive industry contributing to the very limited price elasticity.

If power can flow freely in the Nordic area – that is to say, transmission lines are not congested – then there will only be one market price. But if the required power trade cannot be handled physically, due to transmission constraints, the market is split into a number of sub-markets, defined by the pricing areas. For example, Denmark splits into two pricing areas (Jutland/Funen and Zealand). Thus, if more power is produced in the Jutland/Funen area than consumption and transmission capacity can cover, this area would constitute a sub-market, where supply and demand would balance out at a lower price than in the rest of the NordPool area.

THE NORDIC POWER MARKET: THE REGULATING MARKET

Imbalances in the physical trade on the spot market must be levelled out in order to maintain the balance between production and consumption, and to maintain power grid stability. Totalling the deviations from bid volumes on the spot market yields a net imbalance for that hour in the system as a whole. If the grid is congested, the market breaks up into area markets, and equilibrium must be established in each area. The main tool for correcting such imbalances, which provides the necessary physical trade and accounting in the liberalised Nordic electricity system, is the regulating market.

The regulating power market and the balancing market may be regarded as one entity, where the TSO acts as an important intermediary or facilitator between the supply and demand of regulating power. The TSO is the body responsible for securing the system functioning in a region. Within its region, the TSO controls and manages the grid, and to this end, the combined regulating power and balancing market is an important tool for managing the balance and stability of the grid (Nordel, 2002). The basic principle for settling imbalances is that participants causing or contributing to the imbalance will pay their share of the costs for re-establishing balance. Since September 2002, the settling of imbalances among Nordic countries has been done based on common rules. However, the settling of imbalances within a region differs from country to country. Work is being done in Nordel to analyse the options for harmonising these rules in the Nordic countries.

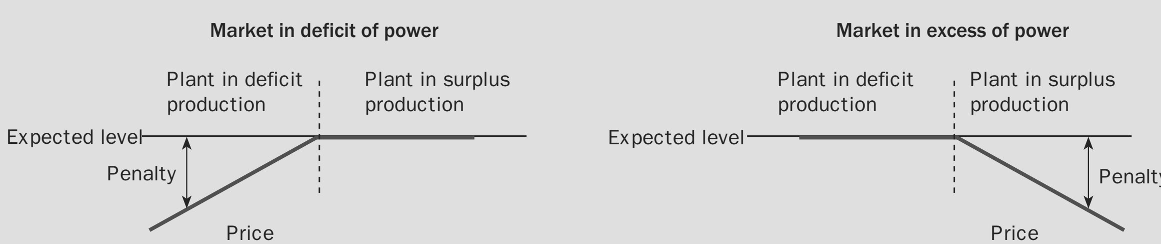
If the vendors' offers or buyers' bids on the spot market are not fulfilled, the regulating market comes into force. This is especially important for wind electricity producers. Producers on the regulating market have to deliver their offers one or two hours before the hour of delivery, and power production must be available within 15 minutes of notice being given. For these reasons, only fast-response power producers will normally be able to deliver regulating power.

It is normally only possible to predict the supply of wind power with a certain degree of accuracy 12–36 hours in advance. Consequently, it may be necessary to pay a premium for the difference between the volume offered to the spot market and the volume delivered. Figure III.5.2 shows how the regulatory market functions in two situations: a general deficit on the market (left part of the figure) and a general surplus on the market (right part of figure).

If the market tends towards a deficit of power, and if power production from wind power plants is lower than offered, other producers will have to adjust regulation (up) in order to maintain the power balance. In this case, the wind producer will be penalised and get a lower price for their electricity production than the spot market price. The further off-track the wind producer is, the higher the expected penalty. The difference between the regulatory curves and the stipulated spot market price in Figure III.5.2 illustrates this. If wind power production is higher than the amount offered, wind power plants effectively help to eliminate market deficit and therefore receive the spot price for the full production without paying a penalty.

If the market tends towards an excess of power, and if power production from the wind power plant is higher than offered, other producers will have to adjust regulation (down) in order to maintain the power balance.

Figure III.5.2: The functioning of the regulatory market



Source: Risø DTU

In this case, the wind producer will be penalised and get a lower price for their electricity production than the spot market price. Again, the further off-track the wind producer, the higher the expected premium. However, if wind power production is lower than the bid, then wind power plants help to eliminate surplus on the market, and therefore receive the spot price for the full amount of production without paying a penalty.

Until the end of 2002, each country participating in the NordPool market had its own regulatory market. In Denmark, balancing was handled by agreements with the largest power producers, supplemented by the possibility of TSOs buying balancing power from abroad if domestic producers were too expensive or unable to produce the required volumes of regulatory power. A common Nordic regulatory market was established at the beginning of 2003, and both Danish areas participate in this market.

In Norway, Sweden and Finland, all suppliers on the regulating market receive the marginal price for power regulation at the specific hour. In Denmark, market suppliers get the price of their bid to the regulation market. If there is no transmission congestion, the regulation price is the same in all areas. If bottlenecks occur in one or more areas, bids from these areas on the regulating market are not taken into account when forming the regulation price for the rest of the system, and the regulation price within the area will differ from the system regulation price.

In Norway, only one regulation price is defined, and this is used both for sale and purchase, at the hour when settling the imbalances of individual participants. This implies that participants helping to eliminate imbalances are rewarded even if they do not fulfil their actual bid. Thus if the market is in deficit of power and a wind turbine produces more than its bid, then the surplus production is paid a regulation premium corresponding to the penalty for those plants in deficit.

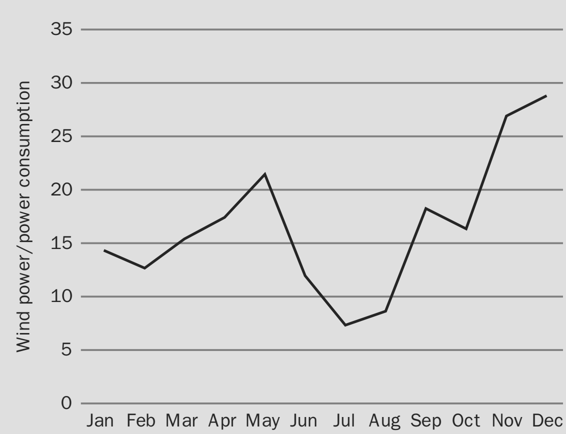
The Impact of Wind Power on the Power Market – Illustrated by the Case of Denmark

Denmark has a total capacity of a little more than 3200 MW of wind power – approximately 2800 MW from land turbines and 400MW offshore. In 2007, around 21 per cent of domestic power consumption was supplied by wind power, which makes Denmark the leading country in terms of wind power penetration (followed by Spain, where the share of wind as a total of electricity consumption is 12 per cent).

Figure III.5.3 shows wind power's average monthly coverage of power consumption in Denmark. Normally, the highest wind-generated production is from January to March. However, as 2006 was a bad wind year in Denmark, this was not the case. The contribution during the summer is normally at a fairly low level.

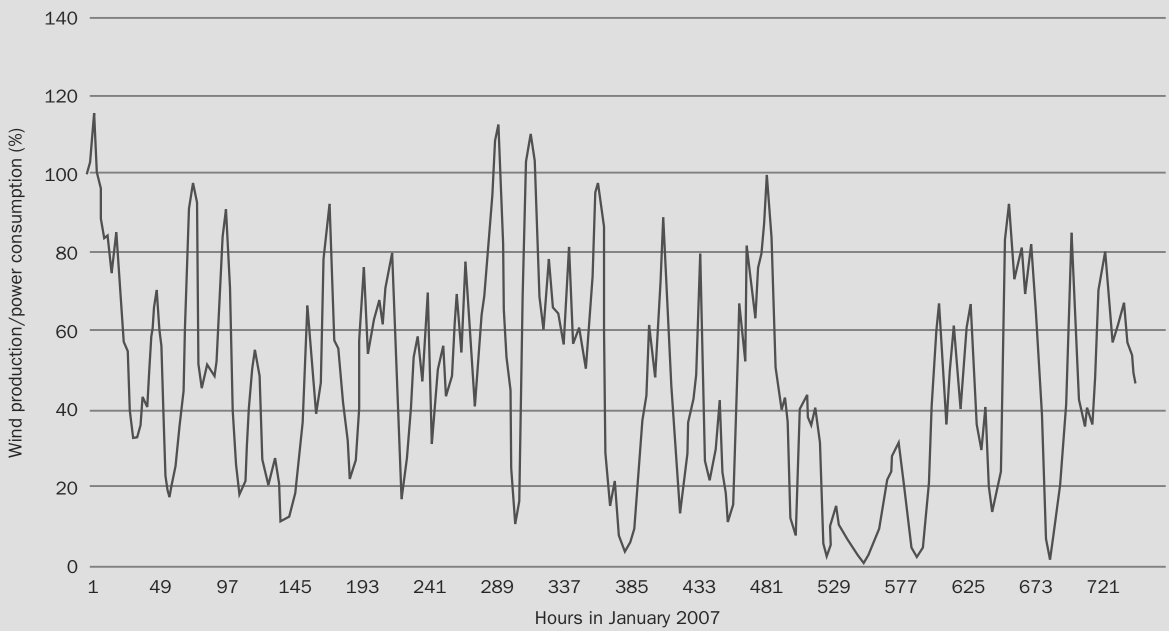
Considerable hourly variations are found in wind power production for Western Denmark, as illustrated in Figure III.5.4. January 2007 was a tremendously

Figure III.5.3: The share of wind power in power consumption calculated as monthly averages for 2006



Source: Risø DTU

Figure III.5.4: Wind power as a percentage of domestic power consumption in January 2007 (hourly basis)



Source: Risø DTU

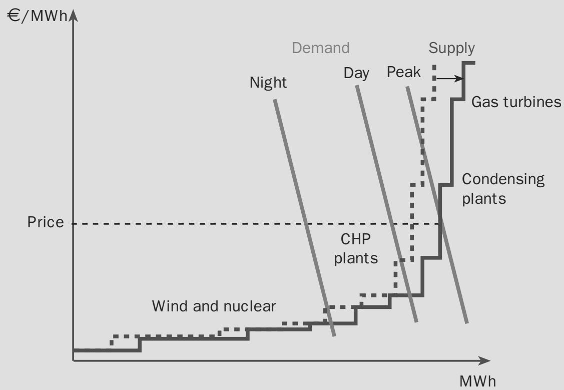
good wind month, with an average supply of 44 per cent of power consumption in Western Denmark, and, as shown, wind-generated power exceeded power consumption on several occasions. Nevertheless, there were also periods with low or no wind in January. In such cases, wind power can significantly influence price determination on the power market. This will be discussed in more detail in the following section.

HOW DOES WIND POWER INFLUENCE THE POWER PRICE AT THE SPOT MARKET?

Wind power is expected to influence prices on the power market in two ways:

1. Wind power normally has a low marginal cost (zero fuel costs) and therefore enters near the bottom of the supply curve. This shifts the supply curve to the right (see Figure III.5.5), resulting in a lower power price, depending on the price elasticity of the power demand. In general, the price of power is expected to be lower during periods of high wind than in periods of low wind.
2. As mentioned above, there may be congestions in power transmission, especially during periods with high wind power generation. Thus, if the available transmission capacity cannot cope with the required power export, the supply area is separated from the rest of the power market and constitutes its own pricing area. With an excess supply of power in this area, conventional power plants have to reduce their production, since it is generally not possible to limit the power production of wind. In most cases, this will lead to a lower power price in this sub-market.

Figure III.5.5: How wind power influences the power spot price at different times of the day



Source: Risø DTU

The way in which wind power influences the power spot price, due to its low marginal cost, is shown in Figure III.5.5. When wind power supply increases, it shifts the power supply curve to the right. At a given demand, this implies a lower spot price on the power market, as shown. However, the impact of wind power depends on the time of day. If there is plenty of wind power at midday, during peak power demand, most of the available generation will be used. This implies that we are at the steep part of the supply curve (see Figure III.5.5) and, consequently, wind power will have a strong impact, reducing the spot power price significantly. But if there is plenty of wind-produced electricity during the night, when power demand is low and most power is produced on base load plants, we are at the flat part of the supply curve and consequently the impact of wind power on the spot price is low.

The congestion problem arises because Denmark, especially the Western Region, has a very high share of wind power, and in cases of high wind power production, transmission lines are often fully utilised.

In Figure III.5.6, this congestion problem is illustrated for January 2007, when the share of wind-generated electricity in relation to total power consumption for West Denmark was more than 100 per cent at certain periods (Figure III.5.6 left part). This means that during these periods, wind power supplied more than all the power consumed in that area. If the prioritised production from small, decentralised CHP plants is added on top of wind power production, there are several periods with a significant excess supply of power, part of which may be exported. However, when transmission lines are fully utilised, there is a congestion problem. In that case, equilibrium between demand and supply needs to be reached within the specific power area, requiring conventional producers to reduce their production, if possible. The consequences for the spot power price are shown in the right graph of Figure III.5.6. By comparing the two graphs, it can be clearly seen that there is a close relationship between wind power in the system and changes in the spot price for this area.

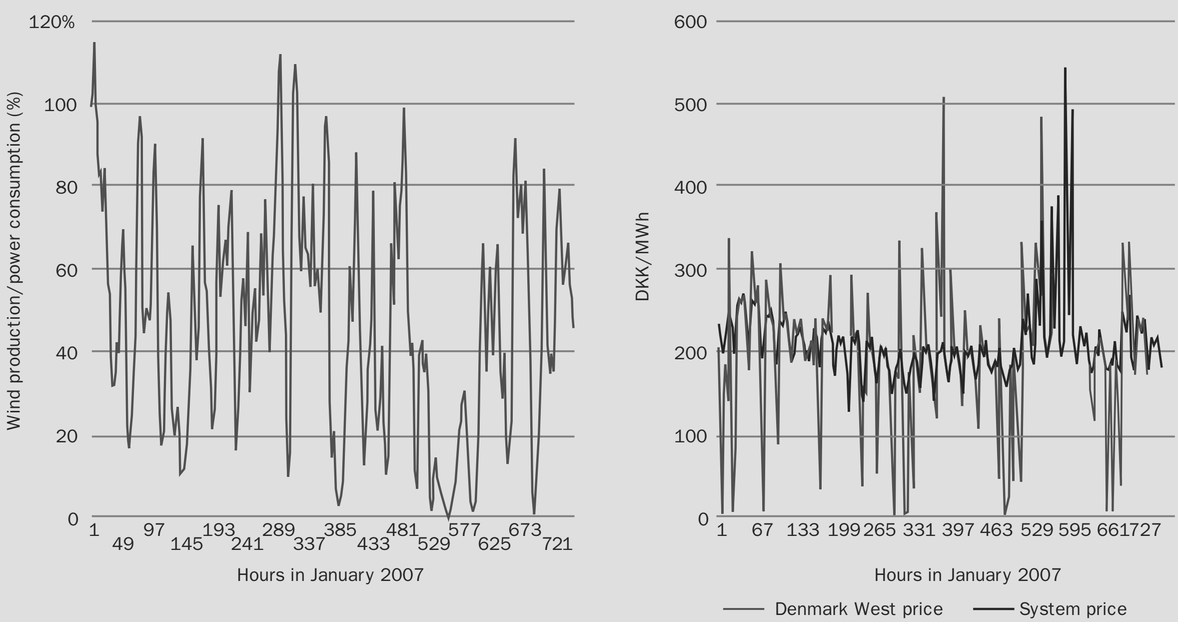
The consequences of the two issues mentioned above for the West Denmark power supply area are discussed below. It should be mentioned that similar studies are available for Germany and Spain, which show almost identical results.

IMPACTS OF WIND POWER ON SPOT PRICES

The analysis here entails the impacts of wind power on power spot prices being quantified using structural analyses. A reference is fixed, corresponding to a situation with zero contribution from wind power in the power system. A number of levels with increasing contributions from wind power are then identified and, relating to the reference, the effect of wind power's power production is calculated. This is illustrated in the left-hand graph in Figure III.5.7, where the shaded area between the two curves approximates the value of wind power in terms of lower spot power prices.

In the right-hand graph in Figure III.5.7, more detail is shown with figures from the West Denmark area. Five levels of wind power production and the corresponding

Figure III.5.6: Left – wind power as percentage of power consumption in Western Denmark; Right – spot prices for the same area and time period



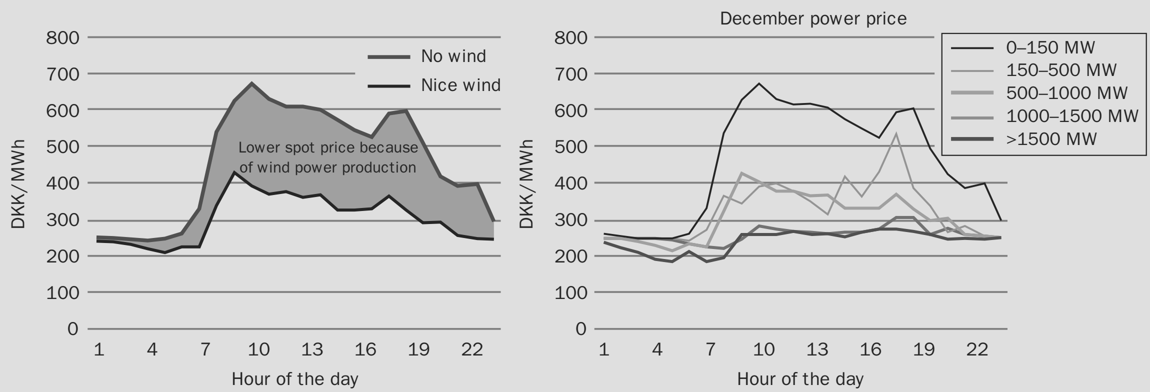
Source: Risø DTU

power prices are depicted for each hour of the day during December 2005. The reference is given by the ‘0–150 MW’ curve, which thus approximates those hours of the month when the wind was not blowing. Therefore, this graph should approximate the prices for an average day in December 2005, in a situation with zero contribution from wind power. The other curves show increasing levels of wind power production: the 150–500 MW curve shows a situation with low wind, increasing to storm in the >1500 MW curve. As shown, the higher the wind power production, the lower the spot power price is in this area. At very high levels of wind power production, the power price is reduced significantly during the day, but only falls slightly during the night. Thus there is a significant impact on the power price, which might increase in the long term if even larger shares of wind power are fed into the system.

Figure III.5.7 relates to December 2005, but similar figures are found for most other periods during 2004 and 2005, especially in autumn and winter, owing to the high wind power production in these periods.

Of course, ‘noise’ in the estimations does exist, implying ‘overlap’ between curves for the single categories of wind power. Thus, a high amount of wind power does not always imply a lower spot price than that with low wind power production, indicating that a significant statistical uncertainty exists. Of course, factors other than wind power production influence prices on the spot market. But the close correlation between wind power and spot prices is clearly verified by a regression analysis carried out using the West Denmark data for 2005, where a significant relationship is found between power prices, wind power production and power consumption.

Figure III.5.7: The impact of wind power on the spot power price in the West Denmark power system in December 2005



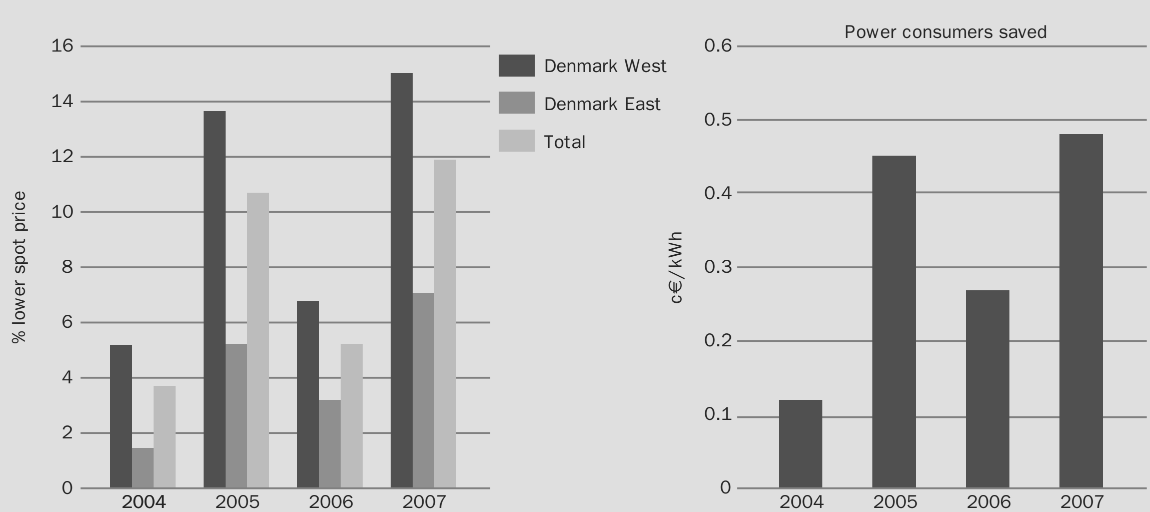
Note: The calculation only shows how the production contribution from wind power influences power prices when the wind is blowing. The analysis cannot be used to answer the question 'What would the power price have been if wind power was not part of the energy system?'.

Source: Risø DTU

When wind power reduces the spot power price, it has a significant influence on the price of power for consumers. When the spot price is lowered, this is beneficial to all power consumers, since the reduction in price applies to all electricity traded – not only to electricity generated by wind power.

Figure III.5.8 shows the amount saved by power consumers in Western and Eastern Denmark due to wind

Figure III.5.8: Annual percentage and absolute savings by power consumers in Western and Eastern Denmark in 2004–2007 due to wind power depressing the spot market electricity price



Source: Risø DTU

power's contribution to the system. Two calculations were performed: one using the lowest level of wind power generation as the reference ('0–150 MW'), in other words assuming that the power price would have followed this level if there was no contribution from wind power in the system, and the other more conservative, utilising a reference of above 500 MW. For each hour, the difference between this reference level and the levels with higher production of wind power is calculated. Summing the calculated amounts for all hours of the year gives the total benefit for power consumers of wind power lowering spot prices of electricity.

Figure III.5.8 shows how much higher the consumer price would have been (excluding transmission tariffs, taxes and VAT) if wind power had not contributed to power production.

In general in 2004–2007, the cost of power to the consumer (excluding transmission and distribution tariffs, taxes, and VAT) would have been approximately 4–12 per cent higher in Denmark if wind power had not contributed to power production. Wind power's strongest impact is estimated to have been for Western Denmark, due to the high penetration of wind power in this area. In 2007, this adds up to approximately 0.5c€/kWh saved by power consumers as a result of wind power lowering electricity prices, compared to the support given to wind power as FITs of approximately 0.7c€/kWh. Thus, although the expenses of wind power are still greater than the financial benefits for power consumers, a significant reduction of net expenses is certainly achieved due to lower spot prices.

Finally, though having a smaller impact, wind power clearly reduces power prices even within the large Nordic power system. Thus although wind power in the Nordic countries is mainly established in Denmark, all Nordic power consumers benefit financially due to the presence of Danish wind power on the market.

III.6 WIND POWER COMPARED TO CONVENTIONAL POWER GENERATION

In this chapter, the cost of conventionally generated power is compared with the cost of wind-generated power. To obtain a comparable picture, calculations for conventional technologies are prepared utilising the Recabs model, which was developed in the IEA Implementing Agreement on Renewable Energy Technology Deployment (IEA, 2008). The cost of conventional electricity production in general is determined by four components:

1. fuel cost;
2. cost of CO_2 emissions (as given by the European Trading System for CO_2, ETS);
3. operation and maintenance (O&M) costs; and
4. capital cost, including planning and site work.

Fuel prices are given by the international markets and, in the reference case, are assumed to develop according to the IEA's *World Energy Outlook 2007* (IEA, 2007c), which rather conservatively assumes a crude oil price of US$63/barrel in 2007, gradually declining to $59/barrel in 2010 (constant terms). Oil prices reached a high of $147/barrel in July 2008. As is normally observed, natural gas prices are assumed to follow the crude oil price (basic assumptions on other fuel prices: coal €1.6/GJ and natural gas €6.05/GJ). As mentioned, the price of CO_2 is determined by the EU ETS market; at present the price of CO_2 is around €25/t.

Here, calculations are carried out for two state-of-the-art conventional plants: a coal-fired power plant and a combined cycle natural gas combined heat and power plant, based on the following assumptions:

- Plants are commercially available for commissioning by 2010.
- Costs are levelised using a 7.5 per cent real discount rate and a 40-year lifetime (national assumptions on plant lifetime might be shorter, but calculations were adjusted to 40 years).
- The load factor is 75 per cent.
- Calculations are carried out in constant 2006-€.

When conventional power is replaced by wind-generated electricity, the costs avoided depend on the degree to which wind power substitutes for each of the four components. It is generally accepted that implementing wind power avoids the full fuel and CO_2 costs, as well as a considerable portion of the O&M costs of the displaced conventional power plant. The level of avoided capital costs depends on the extent to which wind power capacity can displace investments in new conventional power plants, and thus is directly tied to how wind power plants are integrated into the power system.

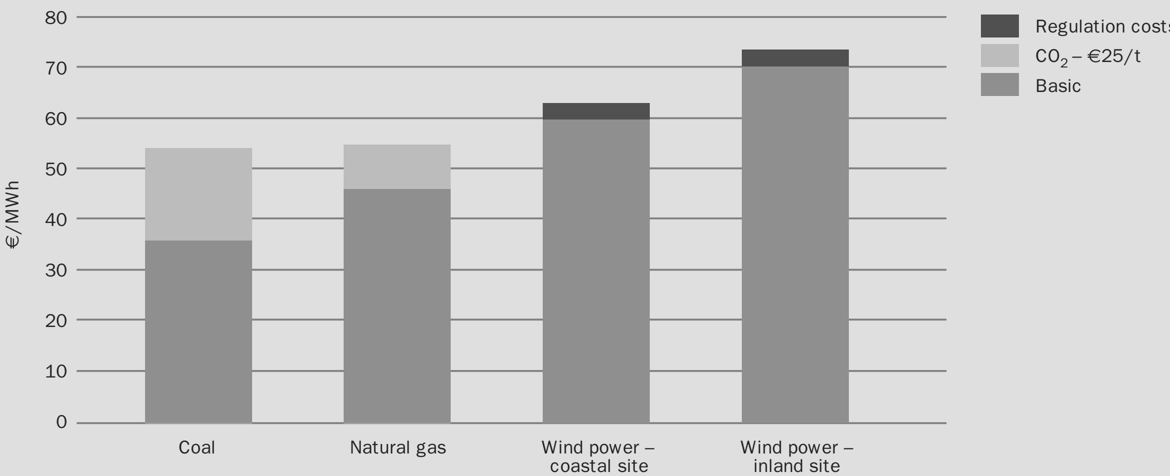
Studies of the Nordic power market, NordPool, show that the cost of integrating variable wind power is, on average, approximately 0.3–0.4c€/kWh of wind power generated at the present level of wind power capacity (mainly Denmark) and with the existing transmission and market conditions. These costs are completely in line with experiences in other countries. Integration costs are expected to increase with higher levels of wind power penetration.

Figure III.6.1 shows the results of the reference case, assuming the two conventional power plants are coming on-stream in 2010. As mentioned, figures for the conventional plants are calculated using the Recabs model, while the costs for wind power are taken from Chapter III.1.

As shown in the reference case, the cost of power generated at conventional power plants is lower than the cost of wind-generated power under the given assumptions of lower fuel prices. Wind-generated power at a European inland site is approximately 33–34 per cent more expensive than natural gas- and coal-generated power.

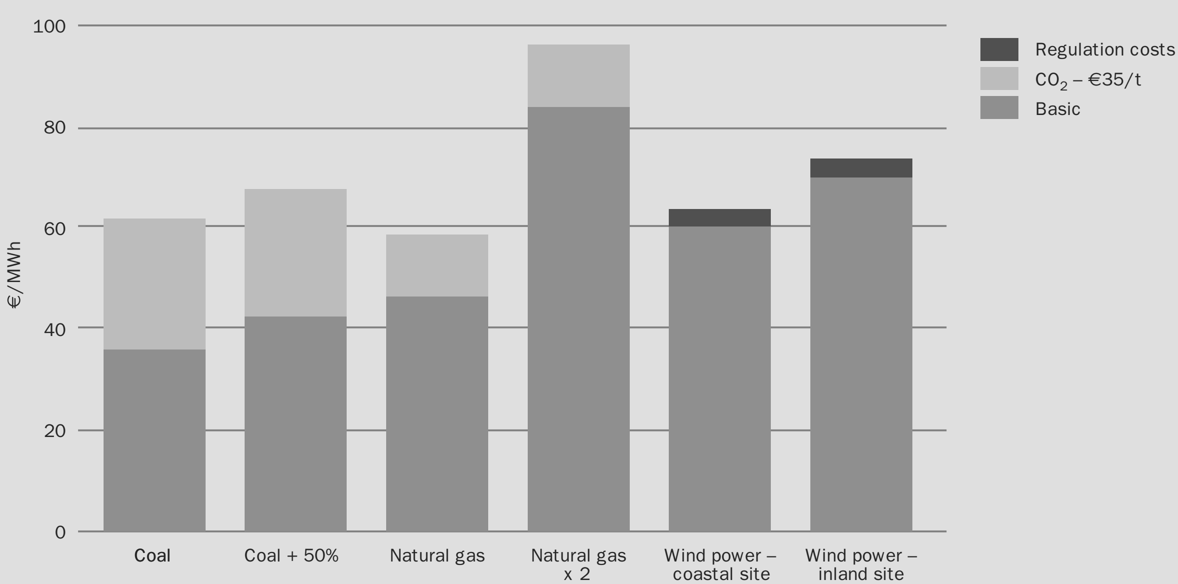
This case is based on the *World Energy Outlook* assumptions on fuel prices, including a crude oil price of $59/barrel in 2010. At present (September 2008), the crude oil price is $120/barrel. Although this oil price is combined with a lower exchange rate for US dollar, the present price of oil is significantly higher

Figure III.6.1: Costs of generated power comparing conventional plants to wind power, 2010 (constant 2006-€)



Source: Risø DTU

Figure III.6.2: Sensitivity analysis of costs of generated power comparing conventional plants to wind power, assuming increasing fossil fuel and CO_2 prices, 2010 (constant 2006-€)



Source: Risø DTU

than the forecast IEA oil price for 2010. Therefore, a sensitivity analysis is carried through and results are shown in Figure III.6.2.

In Figure III.6.2, the natural gas price is assumed to double compared to the reference, equivalent to an oil price of $118/barrel in 2010, the coal price to increase by 50 per cent and the price of CO_2 to increase to €35/t from €25/t in 2008. As shown in Figure III.6.2, the competitiveness of wind-generated power increases significantly: costs at the inland site become lower than generation costs for the natural gas plant and only around 10 per cent more expensive than the coal-fired plant. At coastal sites, wind power produces the cheapest electricity.

Finally, as discussed by Awerbuch (2003a), the uncertainties related to future fossil fuel prices mentioned above imply a considerable risk for future generation costs of conventional plants. Conversely, the costs per kWh generated by wind power are almost constant over the lifetime of the turbine, following its installation. Thus, although wind power might currently be more expensive per kWh, it can account for a significant share in a utilities' portfolio of power plants, since it hedges against unexpected rises in prices of fossil fuels in the future. The consistent nature of wind power costs justifies a relatively higher cost compared to the uncertain risky future costs of conventional power.

III.7 EMPLOYMENT

Employment in the Wind Energy Sector

WIND ENERGY EMPLOYMENT IN EUROPE

Wind energy companies in the EU currently employ around 108,600 people.[6] For the purposes of this chapter, direct jobs relate to employment in wind turbine manufacturing companies and with sub-contractors whose main activity is supplying wind turbine components. Also included are wind energy promoters, utilities selling electricity from wind energy, and major R&D, engineering and specialised wind energy services. Any companies producing components, providing services, or sporadically working in wind-related activities are deemed to provide indirect employment.

The addition of indirect employment affects results significantly. The European Commission, in its EC Impact Assessment on the Renewable Energy Roadmap (EC, 2006), found that 150,000 jobs were linked to wind energy. The European Renewable Energy Council (EREC, 2007) report foresees a workforce of 184,000 people in 2010, but the installed capacity for that year has probably been underestimated. Therefore, the figure for total direct and indirect jobs is estimated at approximately 154,000 jobs.

These two figures of 108,600 direct and 154,000 total jobs can be compared with the results obtained by EWEA in its previous survey for *Wind Energy – The Facts* (EWEA, 2003) of 46,000 and 72,275 workers respectively. The growth experienced between 2003 and 2007 (236 per cent) is consistent with the evolution of the installed capacity in Europe (276 per cent – EWEA, 2008b) during the same period and with the fact that most of the largest wind energy companies are European.

A significant proportion of the direct wind energy employment (around 75 per cent) is in three countries, Denmark, Germany and Spain, whose combined installed capacity adds up to 70 per cent of the total in the EU. Nevertheless, the sector is less concentrated now than it was in 2003, when these three countries accounted for 89 per cent of the employment and 84 per cent of the EU installed capacity. This is due to the opening of manufacturing and operation centres in emerging markets and to the local nature of many wind-related activities, such as promotion, O&M, engineering and legal services.

Germany (BMU, 2006 and 2008) is the country where most wind-related jobs have been created, with around 38,000 directly attributable to wind energy companies[7] and a slightly higher amount from indirect effects. According to the German Federal Ministry of the Environment, in 2007 over 80 per cent of the value chain in the German wind energy sector was exported.

Table III.7.1: Direct employment from wind energy companies in selected European countries

Country	No of direct jobs
Austria	700
Belgium	2000
Bulgaria	100
Czech Republic	100
Denmark	23,500
Finland	800
France	7000
Germany	38,000
Greece	1800
Hungary	100
Ireland	1500
Italy	2500
The Netherlands	2000
Poland	800
Portugal	800
Spain	20,500
Sweden	2000
UK	4000
Rest of EU	400
TOTAL	**108,600**

Sources: Own estimates, based on EWEA (2008a); ADEME (2008); AEE (2007); DWIA (2008); BMU (2008)

In Spain (AEE, 2007), direct employment is 20,500 people. When indirect jobs are taken into account, the figure goes up to 37,730. According to the AEE, 30 per cent of the jobs are in manufacturing companies; 34 per cent in installation, O&M and repair companies, 27 per cent in promotion and engineering companies, and 9 per cent in other branches.

Denmark (DWIA, 2008) has around 23,500 employees in wind turbine and blade manufacturing and major sub-component corporations.[8]

The launch of new wind energy markets has fostered the creation of employment in other EU countries. Factors such as market size, proximity to one of the three traditional leaders, national regulation and labour costs determine the industry structure, but the effect is always positive.

France (2454 MW installed, 888 MW added in 2007 and an estimated figure of 7000 wind energy jobs), for instance, shows a wealth of small developers, consultants, and engineering and legal service companies. All the large wind energy manufacturers and developers and some utilities have opened up a branch in this country. France also counts on several wind turbine and component manufacturers producing in its territory.

In the UK, the importance of offshore wind energy and small-scale wind turbines is reflected by the existence of many job-creating businesses in this area. This country also has some of the most prestigious wind energy engineering and consultancy companies. The British Wind Energy Association is conducting a study of present and future wind energy employment; preliminary results point to the existence of around 4000 to 4500 direct jobs.

Another example is Portugal, where the growth of the market initially relied on imported wind turbines. From 2009 onwards, two new factories will be opened, adding around 2000 new jobs to the 800 that already exist.

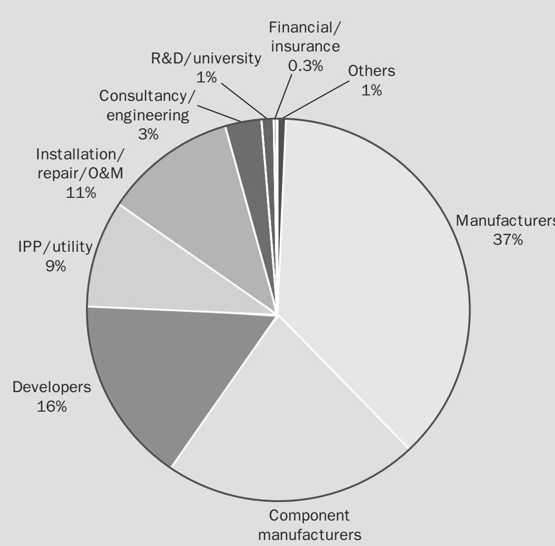
Some other EU Member States, such as Italy, Greece, Belgium, The Netherlands, Ireland and Sweden, are also in the 1500 to 2500 band. The situation in the new Member States is diverse, with Poland in a leading position. Wind energy employment will probably rise significantly in the next three to five years, boosted by a combination of market attractiveness, a highly skilled labour force and lower production costs.

In terms of gender, the survey conducted by EWEA shows that males make up 78 per cent of the workforce. In the EU labour market as a whole, the figure is 55.7 per cent. Such a bias reflects the traditional predominance of men in production chains, construction work and engineering.

By type of company, wind turbine and component manufacturers account for most of the jobs (59 per cent). Within these categories, companies tend to be bigger and thus employ more people.

Wind energy figures can be measured against the statistics provided by Eurostat (2007). The energy sector employs 2.69 million people, accounting for 1.4 per cent of total EU employment. Approximately half this

Figure III.7.1: Direct employment by type of company, according to EWEA survey



Source: EWEA (2008a)

amount is active in the production of electricity, gas, steam and hot water. Employment from the wind energy sector would then make up around 7.3 per cent of that amount; and it should be noted that wind energy currently meets 3.7 per cent of EU electricity demand. Although the lack of specific data for electricity production prevents us from making more accurate comparisons, this shows that wind energy is more labour intensive than the other electricity generating technologies. This conclusion is consistent with earlier research.

Finally, there is a well-documented trend of energy employment decline in Europe, particularly marked in the coal sector. For instance, British coal production and employment have dropped significantly, from 229,000 workers in 1981 to 5500 in 2006. In Germany, it is estimated that jobs in the sector will drop from 265,000 in 1991 to less than 80,000 in 2020. In EU countries, more than 150,000 utility and gas industry jobs disappeared in the second half of the 1990s and it is estimated that another 200,000 jobs will be lost during the first half of the 21st century (UNEP, ILO and ITUC, 2007). The outcomes set out in the previous paragraphs demonstrate that job losses in the European energy sector are independent of renewable energy deployment and that the renewable energy sector is, in fact, helping to mitigate these negative effects in the power sector.

JOB PROFILES OF THE WIND ENERGY INDUSTRY

The lack of any official classification of wind energy companies makes it difficult to categorise wind energy jobs. However, Table III.7.2 summarises the main profiles required by wind energy industries, according to the nature of their core business.

THE SHORTAGE OF WORKERS

In the last two to three years, wind energy companies have repeatedly reported a serious shortage of workers, especially within certain fields. This scarcity coincides with a general expansion of the European economy, where growth rates have been among the fastest since the end of the Second World War. An analysis of Eurostat (2008b) statistics proves that job vacancies have been difficult to cover in all sectors. The rotation of workers is high, both for skilled and non-skilled workers.

In the case of wind energy, the general pressure provoked by strong economic growth is complemented by the extraordinary performance of the sector since the end of the 1990s. In the 2000–2007 period, wind energy installations in the EU increased by 339 per cent (EWEA, 2008b). This has prompted an increase in job offers in all the sub-sectors, especially in manufacturing, maintenance and development activities.

Generally speaking, the shortage is more acute for positions that require a high degree of experience and responsibility:

- From a manufacturer's point of view, two major bottlenecks arise: one relates to engineers dealing with R&D, product design and the manufacturing processes; the other to O&M and site management activities (technical staff).
- In turn, wind energy promoters lack project managers; the professionals responsible for getting the permits in the country where a wind farm is going to be installed. These positions require a combination of specific knowledge of the country and wind energy expertise, which is difficult to gain in a short period of time.
- Other profiles, such as financiers or sales managers, can sometimes be hard to find, but generally this is less of a problem for wind energy companies, possibly because the necessary qualifications are more general.
- The picture for the R&D institutes is not clear: of the two consulted, one reported no problems, while the other complained that it was impossible to hire experienced researchers. It is worth noting that the remuneration offered by R&D centres, especially if

Table III.7.2: Typical wind energy job profiles demanded by different types of industry

Company type	Field of activity	Main job profiles
Wind energy manufacturers	Wind turbine producers, including manufacturers of major sub-components and assembly factories.	• Highly qualified chemical, electrical, mechanical and materials engineers dealing with R&D issues, product design, management and quality control of production process. • Semi-skilled and non-skilled workers for the production chains. • Health and safety experts. • Technical staff for the O&M and repair of wind turbines. • Other supporting staff (including administrative, sales managers, marketing and accounting).
Developers	Manage all the tasks related to the development of wind farms (planning, permits, construction and so on).	• Project managers (engineers and economists) to coordinate the process. • Environmental engineers and other specialists to analyse the environmental impacts of wind farms. • Programmers and meteorologists for wind energy forecasts and prediction models. • Lawyers and economists to deal with the legal and financial aspects of project development. • Other supporting staff (including administrative, sales managers, marketing and accounting).
Construction, repair and O&M	Construction of the wind farm, regular inspection and repair activities.[9]	• Technical staff for the O&M and repair of wind turbines. • Electrical and civil engineers for the coordination of construction works. • Health and safety experts. • Specialists in the transport of heavy goods. • Electricians. • Technical staff specialised in wind turbine installation, including activities in cranes, fitters and nacelles. • Semi-skilled and non-skilled workers for the construction process. • Other supporting staff (including administrative, sales managers and accounting).
Independent power producers, utilities	Operation of the wind farm and sale of the electricity produced.	• Electrical, environmental and civil engineers for the management of plants. • Technical staff for the O&M of plants, if this task is not sub-contracted. • Health and safety experts. • Financiers, sales and marketing staff to deal with the sale of electricity. • Other supporting staff (including administrative and accounting).
Consultancies, legal entities, engineering, financial institutions, insurers, R&D centres and others	Diverse specialised activities linked to the wind energy business.	• Programmers and meteorologists for the analysis of wind regimes and output forecasts. • Engineers specialised in aerodynamics, computational fluid dynamics and other R&D areas. • Environmental engineers. • Energy policy experts. • Experts in social surveys, training and communication. • Financiers and economists. • Lawyers specialised in energy and environmental matters. • Marketing personnel and event organisers.

they are governmental or university-related, is below the levels offered by private companies.

The quality of the university system does not seem to be at the root of the problem, although recently graduated students often need an additional specialisation that is given by the wind company itself. The general view is that the number of engineers graduating from European universities on an annual basis does not meet the needs of modern economies, which rely heavily on manufacturing and technological sectors.

In contrast, there seems to be a gap in the secondary level of education, where the range and quality of courses dealing with wind-related activities (mainly O&M, health and safety, logistics, and site management) are inadequate. Policies aimed at improving the educational programmes at pre-university level – dissemination campaigns, measures to encourage worker mobility and vocational training for the unemployed – can help overcome the bottleneck, and at the same time ease the transition of staff moving from declining sectors.

Employment Prediction and Methodology

METHODOLOGICAL APPROACHES TO EMPLOYMENT QUANTIFICATION

The quantification of wind energy employment is a difficult task for several reasons. First, it encompasses many company profiles, such as equipment manufacturing, electricity generation, consulting services, finance and insurance, which belong to different economic sectors. Second, we cannot rely on any existing statistics to estimate wind energy figures, as they do not distinguish between electricity and equipment manufacturing branches. And finally, the structure of the sector changes rapidly and historical data cannot be easily updated to reflect the current situation.

For these reasons, measurement initiatives must rely on a number of methodologies, which can largely be grouped under two headings:

1. data collection based on surveys and complemented by other written evidence; and
2. data collection based on estimated relationships between sectors, vectors of activity and input/output tables.

Surveys

Surveys are the best way to collect information on direct employment, especially when additional aspects – gender issues, employment profiles, length of contracts and other qualitative information – need to be incorporated. Surveys have significant limitations, notably the correct identification of the units that need to be studied and the low percentage of responses (see, for example, Rubio and Varas, 1999; Schuman and Stanley, 1996; Weisberg et al., 1996). When these problems arise, results need to be extrapolated and completed by other means.

Estimated Relationships

Estimated relationships, including input/output tables, can be used to estimate both direct and indirect employment impacts. These models require some initial information, collected by means of a questionnaire and/or expert interviews, but then work on the basis of technical coefficients (Leontief, 1986; Kulisic et al., 2007). The advantages of estimated models are based on the fact that they reflect net economic changes in the sector that is being studied, other related economic sectors and the whole of the economic system. These models also constitute the basis for the formulation of forecasts. The disadvantages relate to the cost of carrying out such studies and the need to obtain an appropriate model. In addition, they do not provide any details at sub-sector level and do not capture gender-related, qualification and shortage issues.

In the last six or seven years, coinciding with the boom of the wind energy sector, several studies have been conducted on the related employment repercussions. A list of the most relevant works can be found in Appendix J. A careful revision of their methodology shows that many of them are, in reality, meta-analyses (that is to say, a critical re-examination and comparison of earlier works), while research based on questionnaires and/or input/output tables is less common. Denmark, Germany and Spain, being the three world leaders in wind energy production and installation, have produced solid studies (AEE, 2007; DWIA, 2008; Lehr et al., 2008; BMU, 2008), but employment in the other EU markets remains largely unknown. In particular, there is a lack of information on some key features affecting the wind energy labour market, such as the profiles that are currently in demand, shortages and gender issues. These issues can best be dealt with through ad hoc questionnaires sent to wind energy companies.

EWEA SURVEY ON DIRECT EMPLOYMENT

As a response to the gaps mentioned above, EWEA has sought to quantify the number of people directly employed by the wind energy sector in Europe by means of a questionnaire. As explained in the previous section on wind energy employment in Europe (page 251), direct jobs relate to employment within wind turbine manufacturing companies and sub-contractors whose main activity is the supply of wind turbine components. Also taken into account are wind energy promoters, utilities selling electricity from wind energy, and major R&D, engineering and specialised wind energy services. Any other company producing components, providing services, or sporadically working in wind-related activities is deemed as providing indirect employment.

The analysts have attempted to minimise the main disadvantages linked to this type of methodology. Consequently, the questionnaire was drafted after careful analysis of previous research in this field, notably the questionnaires that had been used in the German, Danish and Spanish studies, and following a discussion with the researchers responsible for these. A draft was sent to a reduced number of respondents, who then commented on any difficulties in understanding the questions and using the Excel spreadsheet, the length of the questionnaire, and some other aspects. The document was modified accordingly.

The final version of the questionnaire was dispatched by email on 19 February 2008 to around 1100 organisations in 30 countries (the 27 EU Member States plus Croatia, Norway and Turkey). It reached all EWEA members and the members of the EU-27 national wind energy associations. The questionnaire was also distributed among participants of the last two European Wind Energy Conferences (EWEC 2006 and 2007). These included:

- wind turbine and component manufacturers;
- developers;
- independent power producers and utilities;
- installation, repair and O&M companies;
- consultancies;
- engineering and legal services;
- R&D centres;
- laboratories and universities;
- financial institutions and insurers;
- wind energy agencies and associations; and
- other interest groups directly involved in wind energy matters.

The document was translated into five EU languages (English, French, German, Spanish and Portuguese), and a number of national wind energy associations decided to write the introductory letter in their own language. A reminder was sent out on 11 March, followed up by telephone calls during April, May, June, July and August.

The questionnaire consisted of 11 questions, divided into three blocks:

1. The first four questions collected information on the profile of the company, its field of activity and the year in which it started operating in the wind energy sector.
2. The next three questions aimed to obtain relevant employment figures. The questionnaire requested both the total number of employees and the number of employees in the wind energy sector, and gave some indication about how to calculate the second figure when a worker was not devoted to wind-related activities full time. The figures were divided up by country, since some companies are transnational, and by sex. It would have been interesting to classify this data by age and level of qualification, but the draft sent to a sample of respondents showed us that this level of detail would be very difficult to obtain and that it would have had a negative impact on the number of replies.
3. The final four questions addressed the issue of labour force scarcity in the wind energy sector, and aimed to obtain information on the profiles that are in short supply and the prospects of wind energy companies in terms of future employment levels and profiles.

Questions 9 and 10 were more speculative, since it is difficult to quantify the exact employment demands in the next five years, but they gave an order of magnitude that could then be compared with the quantitative approaches of input/output tables used by other researchers.

The questionnaire was complemented by in-depth interviews with a selection of stakeholders that suitably reflected the main wind energy sub-sectors and EU countries. The interviews were carried out by phone, by email or face-to-face. They were aimed at verifying the data obtained from the questionnaires and at addressing some of the topics that could not be dealt with, notably a more thorough explanation of the job profiles demanded by the industry and the scarcity problem.

By the end of August 2008, 324 valid questionnaires had been received, implying a response rate of around 30 per cent. When looking at the responses, it is clear that it was mostly the largest turbine and component manufacturers, as well as the major utilities, that answered the questionnaire. The replies therefore do not provide an accurate representation of the industry as a whole.

The figures are good for this type of survey, but supplementary sources need to be used to fill in the gaps and validate results. This has been done in several ways:

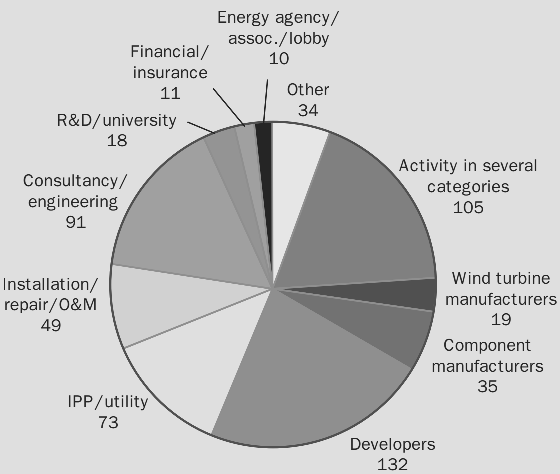
- The use of thematic surveys and input/output analysis carried out in Denmark, France, Germany and Spain. The last two countries base their numbers on questionnaires very similar to the ones used by EWEA, an exhaustive analysis of the governmental registers for tax-related purposes, and the application of national input/output tables and other technical coefficients to estimate the indirect effects. The Danish Wind Energy Association collects information about employment from all its members on an annual basis and then predicts indirect and induced jobs through technical coefficients and multipliers. The French Environment and Energy Management Agency (ADEME) bases its estimates on net production/employment ratios (imports have been disregarded).
- The review of the annual reports/websites of the main wind energy companies, notably the large wind energy manufacturers, component manufacturers, wind energy developers and utilities. As these

Table III.7.3: EWEA survey results[10]

Country	No of direct jobs
Austria	270
Belgium	1161
Bulgaria	91
Cyprus	1
Czech Republic	52
Denmark	9875
Estonia	5
Finland	194
France	2076
Germany	17,246
Greece	812
Hungary	11
Ireland	870
Italy	1048
Latvia	6
Lithuania	6
The Netherlands	824
Poland	312
Portugal	425
Romania	27
Slovakia	22
Slovenia	4
Spain	10,986
Sweden	1234
UK	2753
Rest of Europe	70
TOTAL	**50,380**

Source: EWEA (2008a)

Figure III.7.2: Number of questionnaires received by type of company



Source: EWEA (2008a)

companies are active in the stock market, they publish some information on their activities and structure that can be used to estimate wind energy figures.

- The registers and the expertise gained by the national wind energy associations. France, the UK and Portugal are currently carrying out thematic studies covering, among other things, employment issues. Their preliminary conclusions have been incorporated into this publication. In other cases, experts from the national associations and governments have been contacted.

Additionally, EWEA is engaged in an in-depth examination of the factors that are behind the repeatedly reported shortage of workers in the wind energy sector and the profiles that are particularly difficult to find. This has been done through in-depth interviews (conducted face-to-face, by email and by phone) with the human resources managers of a selection of wind energy companies from different branches and geographical areas. The results were compared with those of the answers to questions 7–10 of the general questionnaire.

Part III Notes

1 'Ex-works' means that site work, foundation and grid connection costs are not included. Ex-works costs include the turbine as provided by the manufacturer, which includes the turbine, blades, tower and transport to the site.

2 In Spain land rental is counted as an O&M cost.

3 The number of observations was generally between 25 and 60.

4 See, for instance, Neij (1997), Neij et al. (2003) or Milborrow (2003).

5 This is in line with observed costs in other countries.

6 For more information on wind energy employment, see EWEA (2008c).

7 The 2006 BMU study found that 43 per cent of gross wind energy jobs (63,900) were direct; the rest, which also included O&M, were indirect. In 2008, the BMU published new data (84,300 jobs), but this does not distinguish between direct and indirect jobs. For the purposes of this publication, we have made the split based on the assumption that the earlier ratio still pertains (43 per cent direct and 57 per cent indirect).

8 Of those, 13,000 come from pure wind turbine and blade manufacturing companies. The remaining 4000 are attributed to major sub-suppliers. Most of these produce for more than one sector. In this publication, such companies are included within the category of 'direct employment' when at least 50 per cent of their turnover comes from sales to wind turbine manufacturers or operators. In addition, the questionnaire that was used as the basis for obtaining the statistics asked about 'jobs that can be attributed to wind-related activities', thus eliminating staff that are devoted to other activities.

9 The Windskill Project (www.windskill.eu/) funded by the European Commission offers a good summary of the profiles that are required in this area.

10 In a few cases, the questionnaires were filled in by the researchers themselves. This occurred when the figures were communicated through a phone call or by email, or when the information needed was available in an annual report or some other publicly available company document.